BALANCED PLANNING FOR GROWTH

Resource and Market Planning Program

RAMPP - 2

EXECUTIVE SUMMARY

JUNE, 1992

PACIFICORP

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EXECUTIVE SUMMARY

Planning how to meet customers' future energy needs is a little like planning a long-distance auto trip. You want to be sure of two things: First, that you have or can get enough fuel, and second, that you can afford to pay for it.

This second report on PacifiCorp's Resource and Market Planning Program (RAMPP) describes how the Company is making sure it will have adequate resources to meet future energy needs at a price customers can afford. RAMPP is the Company's response to least cost planning, also referred to as integrated resource planning.

BALANCED
PLANNING
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NEW DIRECTIONS IN POWER PLANNING

Electricity resource planning was once a fairly simple task. Planners essentially drew two lines: One a forecast of power demand and the other a projection of power supplies. The point where the two lines crossed showed when more resources would be needed, and power plants were planned and built accordingly.

Today the goal of resource planning is still the same: To make sure utilities have the power supplies they need to economically meet customers' future needs. But the process of resource planning has changed. It has become much more complex. More future possibilities are considered; more resource options are assessed.

For example, this RAMPP-2 report is based not on a single forecast of power demand — but on 26 possible futures. It looks at the variables that affect both energy supply and demand, and examines ways in which the Company could respond to unexpected changes in its resource system, in loads, and in the cost and availability of future resources.

There are two main reasons for the increased complexity in resource planning: Changes in technology have made more resource options available, and changes in society have led to more extensive analysis and more public involvement in energy decisions.

THE PUBLIC TAKES A FRONT SEAT

Citizens and regulators want to assure that utilities will select resource options that are both environmentally and economically sound.

Consumers today are highly concerned about how electricity is produced and used. They have stepped up their involvement in energy decisions, and are particularly concerned about the environmental impacts of electricity generation and transmission.

This strong public interest in energy decisions is one of the reasons more and more regulatory commissions are requiring utilities to prepare least cost plans with substantial public involvement.

Members of the public have been extensively involved in the entire RAMPP-2 process. The RAMPP-2 Advisory Group included representatives from public agencies, public interest groups, and customer groups. The Advisory Group held 11 all-day meetings to discuss the work in progress as RAMPP-2 was developed and offer comments, suggestions and concerns for PacifiCorp to consider and incorporate into the plan. For example, the Advisory Group helped the Company define a wide range of potential futures to examine in its analysis. In addition, subgroups of the Advisory group met to discuss Demand Side Resources, Forecasting, Resource Cost Effectiveness, and Environmental Costs.

A draft copy of the report was distributed to the Advisory group for their comments. Most of the comments requested additional information in the report. As a result, the report provides better documentation of the planning process.

WHAT'S A RAMPP?

PacifiCorp's Resource and Market Planning Program (RAMPP) describes the decision-making framework the Company will use to manage the future balance between power supply and demand.

RAMPP is also PacifiCorp's official response to regulatory requirements for a least cost, or integrated resource, plan. A number of regulatory commissions require utilities to prepare plans that show how the utility will meet future energy needs at the lowest cost to both the company and its customers, consistent with the long-term public interest.

In PacifiCorp's service area, Utah and Montana will soon be issuing guidelines for the preparation of least cost plans. The Oregon and Washington regulatory commissions already require utilities in those states to prepare and submit every two years a plan that:

- Examines a range of forecasts for the energy needs of its customers;
- Considers all feasible alternatives for meeting those needs;
- Assesses the costs of various alternative resources;
- Describes a long-range plan and a shorter term action plan for balancing supply and demand; and
- Has been prepared with substantial public involvement.

RAMPP meets and exceeds these requirements. It goes beyond strict least cost planning, and considers both resource and market conditions for making resource decisions.

PacifiCorp's integrated system provides service in seven states. However, the Company plans and operates as one system. Therefore, the Company does not prepare a separate plan for each state Commission. Planning is done for the entire system.

RAMPP-2 details PacifiCorp's most current planning information. It describes the assumptions, strategies and principles that will guide future supply and demand decisions. As RAMPP-3 is prepared, that process, and the underlying assumptions and strategies, will be updated using current information.

RAMPP-2 does not lock the Company into a rigid resource plan for the next 20 years. Rather, it describes a process to be used in making future decisions.

By emphasizing a process and a planning framework rather than focusing on a single, rigid plan, the Company retains the flexibility it needs to respond to changing conditions.

WHAT WE BELIEVE IN

Through its resource and market planning, PacifiCorp must strike a balance between customers' anticipated needs and the resources available. In deciding which resources to employ when, PacifiCorp considers not only the specific characteristics of each resource, but also how various combinations of resources would affect the system and the Company's ability to meet customer needs.

PacifiCorp is guided in its resource and market planning by eight overall principles:

Minimizing Cost and Retail Price Impact

Reliability

Efficiency

Environmental Responsibility

Dynamic Balance

Flexibility

Diversity

Innovation

Minimizing Cost and Retail Price Impact

The Company's top priority is meeting future power needs while keeping costs and retail prices as low as possible to remain competitive in the energy marketplace.

Reliability

All resource choices should be evaluated according to whether they help the Company provide reliable service to customers.

Efficiency

This includes enhancing the efficient operation of the Company's existing system, identifying beneficial arrangements with other resource providers, and helping customers use energy more efficiently.

Environmental Responsibility

The Company will continue to improve its business operations to mitigate impacts on natural resources and the environment, and will continue to integrate into its resource planning a consideration of environmental impacts.

Dynamic Balance

The desired balance is an economically efficient margin of resources over loads.

Flexibility

A variety of resource options will be employed as needed to respond to changing circumstances.

Diversity

The Company will maintain a broad variety of resource options to hedge the risks associated with an uncertain future.

Innovation

PacifiCorp is willing to take calculated risks and try new ideas to better meet customer and shareholder needs. The Utah Power/Pacific Power merger is one example of a creative approach to resource management.

PREPARING FOR AN UNCERTAIN FUTURE

The central dilemma in resource planning is: How can the Company plan today to cost effectively meet customers' energy needs tomorrow, when future conditions are unknown? What actions must the Company take in the short run to meet customers' energy needs in the long run?

RAMPP-2 approached that dilemma by looking at possible ways in which the future might evolve, and how the Company could respond in each case. The report considers 26 possible futures, drawn from four forecasts that depict varying levels of load growth based on economic and demographic variables, four scenarios of circumstances that could affect either the cost or availability of resources or push load growth even higher than the level indicated in the high forecast, and 18 sensitivities from special conditions which would affect resource planning.

Four Forecasts

The four load forecasts indicate load growth that is:

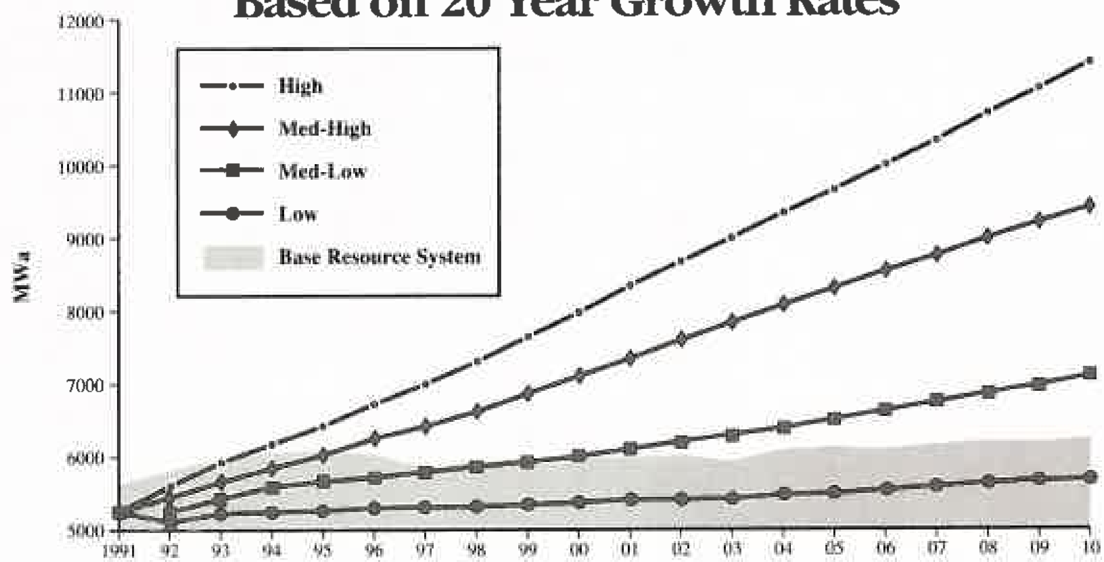
- **High**
- **Medium High**
- **Medium Low**
- **Low**

The four forecasts cover about 90 percent of the possibilities for future load levels, and assume no major changes in the existing institutions and policies that affect power supplies. Table 1 shows the level of load growth associated with each forecast, and provides other information about how each forecast level would affect the system. Figure 2 charts the four levels of load growth compared to PacifiCorp's existing resource system.

Table 1 — Key Forecast Information

Forecast	Energy Growth Rate	Total System MWa at 2011	Total MWa Added	Total System MW at 2011	Total MW Added
Low	0.5	5,595	520	7,241	654
Med-Low	1.7	7,040	1,912	9,194	2,462
Med-High	3.1	9,453	4,030	12,405	5,350
High	4.0	11,460	5,190	15,120	7,808

Figure 2 — Firm Energy 1991-2010 Based on 20 Year Growth Rates



Four Scenarios

The scenarios introduce the possibility of a major change not captured by the forecasts. The four scenarios analyzed in RAMPP-2 were:

- **Electrification** — A major breakthrough in the cost-effectiveness and environmental benefits of using electricity in certain sectors could boost usage higher than the levels indicated by the high forecast.
- **Loss of Resources** — Concerns over fish protection could cause various regulatory or legislative initiatives. New regulations or laws could cause the Company to lose some flexibility in how it uses some of its hydro resources, and how available purchased hydro would be.
- **High Gas Prices** — Natural gas prices could turn out to be higher than assumed in the base forecasts. In the high gas prices case the gas price begins higher and in the later years, escalates faster than in the base case.
- **CO_2 Tax** — Major national and international commitments to reduce carbon dioxide emissions could result in a tax. This scenario assumes enactment of a federal law that would tax CO_2 emissions at $30 per ton.

Eighteen Sensitivities

Sensitivities enabled other future uncertainties to be included in planning. The sensitivities can be grouped into the following categories:

- **Environmental**—Four levels of external environmental costs are developed. Each level is added to the existing resource costs to develop a separate environmental resource plan. A fifth sensitivity uses the high gas prices with environmental costs.

- **Renewable Resources** — One sensitivity assumes renewable resources cost 20 percent less than they currently do. Another restricts resource choices to only acquire renewables.

- **Demand Side Acquisition**—To test the implications of demand side acquisitions which turn out differently than the Company's base plans, one sensitivity assumes acquisitions are 30 percent higher, and another assumes acquisitions are 30 percent lower.

- **Plant Performance** — One sensitivity assumes that the Company's thermal plants operate less than in the base cases, and one assumes that water levels for the hydro plants are higher than in the base cases.

- **Load Uncertainty** — This is the greatest uncertainty facing resource planners. The Company includes eight sensitivities which changes the level of load growth in the middle of the planning period, to mimic the manner in which planners must respond to uneven load growth from one year to the next.

PORTFOLIO OF RESOURCES

After all these future possibilities have been determined, RAMPP-2 tests whether PacifiCorp's portfolio of resources would be adequate and flexible enough to meet the resource needs associated with each case.

The resource portfolio includes a broad range of alternatives that fall into three categories:

Existing System

Resources that are already on-line, as well as their enhancements and efficiency improvements. These include the Company's thermal plants, hydro resources, power contracts, and system effeciencies. The report also discusses various influences on the system that need to be considered in resource planning, such as the transmission network, relicensing of hydro resources, and the flexibility added by wholesale purchases and sales.

Demand Side Alternatives

Energy efficiency programs designed to acquire resources by helping customers use energy more efficiently. Many of PacifiCorp's programs use a new financing mechanism developed by the Company called the Energy Service charge (ESc). Through this mechanism, the Company finances a customer's up front costs for efficiency improvements; the customer then repays the Company out of his or her energy savings through an Energy Service charge on the monthly bill.

Supply Side Alternatives

New generation sources include traditional as well as new technologies. They are evaluated on several characteristics, including costs, emissions, dispatchability, risks, and others.

Portfolio of Resources

Existing System

- Thermal plants
- Hydro plants
- Purchased power
- Efficiencies

Demand Side Resources

- Residential new construction
- Residential weatherization
- Appliance retrofit
- Commercial new construction
- Commercial retrofit
- Industrial

Supply Side Resources

- Wind
- Geothermal
- Solar
- Cogeneration
- Gas-fired simple cycle combustion turbines
- Gas-fired combined cycle combustion turbines
- Coal-fired plants

RESULTS

Applying the resource portfolio to each of the possible futures (forecasts, scenarios and sensitivities) produced an illustrative plan (resource plan) for each future.

The illustrative plans demonstrate how the Company can flexibly and economically meet customers' energy and capacity needs given a broad range of future possibilities.

Figure 3 shows the year-by-year additions that would occur under medium-high load growth. Figure 4 shows the resource mix that would be used by the year 2001 to meet the needs of customers under each of the four forecasts. Figure 5 shows the resource mix that would be used by the year 2010.

Figure 3 — Illustrative Plan Medium-High Forecast

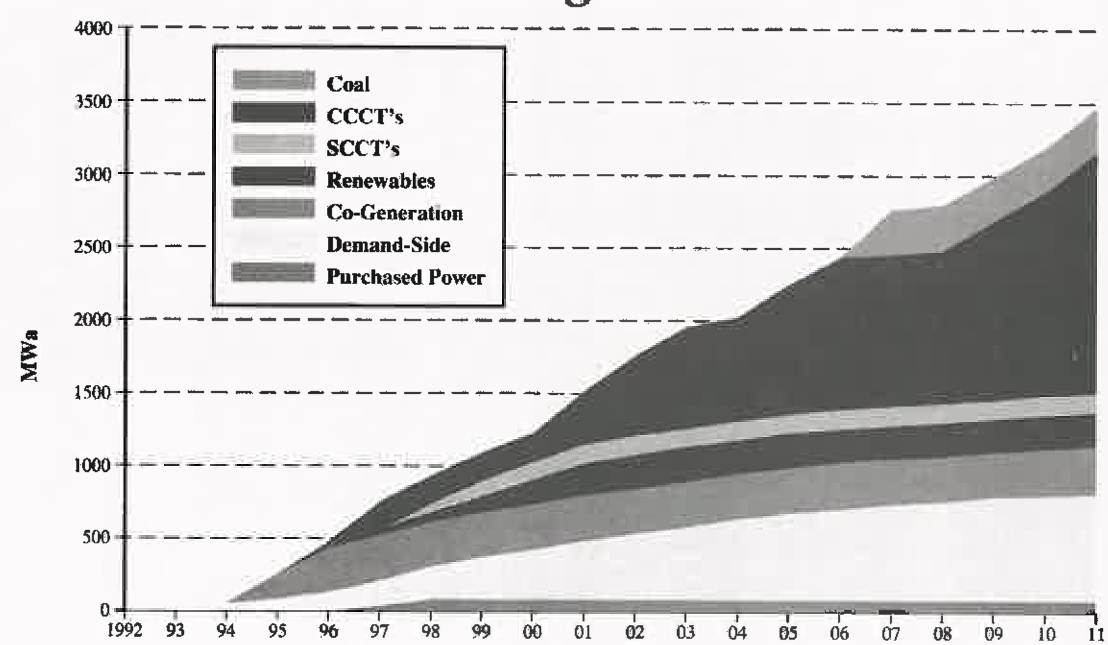
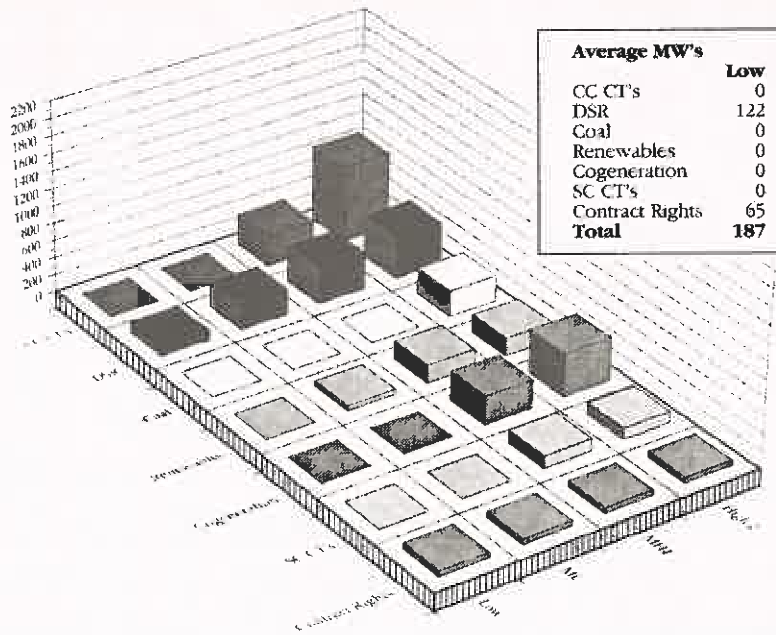
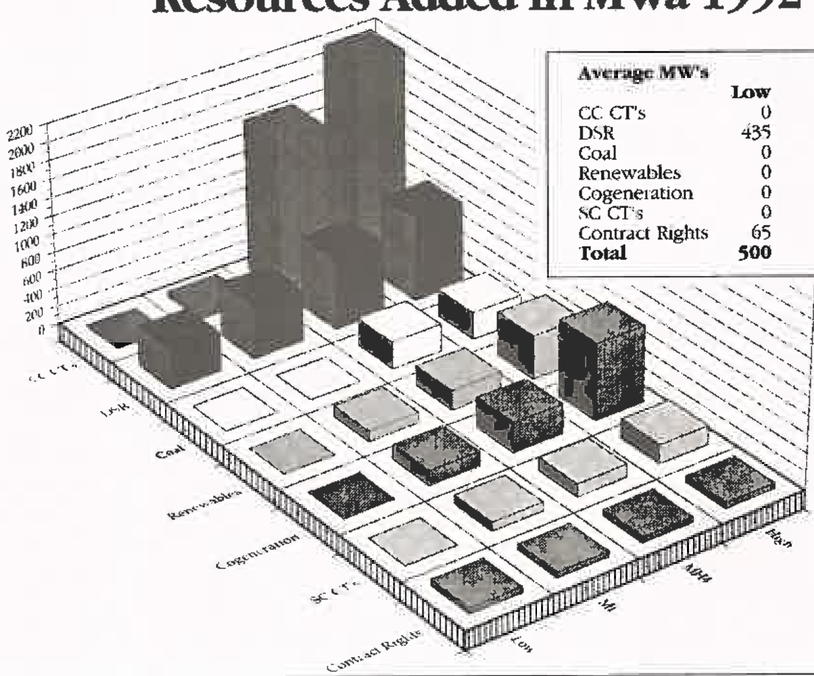


Figure 4 — 4 Forecasts
Resources Added in MWa 1992-2001



Average MW's	Low	ML	MH	High
CC CT's	0	0	350	875
DSR	122	287	418	485
Coal	0	0	0	300
Renewables	0	60	208	208
Cogeneration	0	0	330	500
SC CT's	0	0	142	130
Contract Rights	65	65	65	65
Total	**187**	**412**	**1513**	**2563**

Figure 5 — 4 Forecasts
Resources Added in MWa 1992-2011



Average MW's	Low	ML	MH	High
CC CT's	0	64	1663	2713
DSR	435	588	781	910
Coal	0	0	300	300
Renewables	0	120	218	481
Cogeneration	0	160	330	840
SC CT's	0	95	142	208
Contract Rights	65	65	65	65
Total	**500**	**1092**	**3499**	**5517**

The illustrative plans provide four overall conclusions:

PacifiCorp can serve a growing electricity load and still keep its prices stable.

Unless the growth in electricity load is very high, the Company can add resources as needed without requiring price increases greater than the level of inflation. Managed growth continues to be a primary goal for PacifiCorp. The Company believes that carefully planned and well-managed growth results in more efficient service and prices for customers and an opportunity for shareholders to earn a reasonable return on their investment.

The Company's merger-related pricing commitments of "no price increases" through the end of 1992 will be met, marking five years of price stability and, in some cases, price reductions. The Company's current strategic goals call for holding retail prices to a level that, on average, does not increase as fast as the rate of inflation. To keep future prices competitive, PacifiCorp will pursue the most cost-effective resources from its portfolio, including merger and acquisition possibilities.

Environmental factors have become increasingly important in the Company's resource planning.

PacifiCorp's current strategic plan includes for the first time a specific environmental goal, which guided the development of RAMPP-2. That goal calls for the Company to:

> **Continue to improve the management of our business operations as they affect natural resources and the environment. Seek new ways to expand Company programs that benefit the environment, while balancing the interests of customers and shareholders.**

To achieve the goal, PacifiCorp will:

- Pursue staged development of renewable resources, including quick implementation of pilot projects for wind power, geothermal production and participation in the Solar Two demonstration project;
- Accelerate its programs for acquiring demand side resources (through increasing the energy efficiency of the Company's customers); and
- Pursue strategies for CO_2 offsets (activities that could help mitigate the Company's CO_2 emissions).

Although load growth is uncertain, it is manageable.

The Company faces a number of uncertainties that will affect its future resource decisions. Chief among those uncertainties is how fast electricity loads will actually grow.

The Company can adjust its resource acquisitions to cost-effectively meet changing levels of load growth. The Company also has broad access to power markets which enables it to efficiently balance supply and demand. The power markets can be used to meet temporary or longer-term shortages, and to sell any temporary surpluses. The revenues from these sales are credited back to retail customers.

PacifiCorp's strategy is to develop and maintain flexible options and a diverse portfolio of resources to be able to adjust resource acquisitions and maintain a reasonable balance. PacifiCorp has an adequate portfolio of resources that gives the Company the flexibility it needs to adjust resource acquisitions and maintain a reasonable balance between supply and demand.

Although the Company faces many other uncertainties, they too are manageable.

Other uncertainties facing the Company include fuel prices, environmental policies and regulations, the results of demand-side resource programs, and the performance of existing resources. Through RAMPP-2, the Company has developed ways to hedge its risks in each of these areas.

Fuel price uncertainty is reduced by the Company's long term coal supplies and the abundance of low-sulfur coal reserves close to the Company's existing generating facilities. Higher gas prices could cause the Company to turn to more renewables and earlier coal.

In the environmental arena, the Company has conducted extensive analyses to assess internal and external environmental costs, and to prepare for the impact those costs might have on resource choices. The illustrative plans indicate that significant gains in reducing emissions per kilowatt hour can be achieved under most load growth conditions.

The acquisition level of demand-side resources is uncertain. It is dependent on load growth and the need for new resources. However, if the Company acquires more or less demand-side resources than anticipated, the price impact on customers would be small, as long as the demand-side resources are acquired cost-effectively. The Company's diverse portfolio and access to markets allow the Company to acquire power needed to meet system needs if demand-side acquisitions do not occur as quickly as planned, and the Company can delay other commitments if demand-side acquisitions occur more quickly than planned.

The Company is reducing the uncertainty associated with current plant performance by continuing its efforts to maintain and increase plant efficiency.

Future requirements will be driven by both capacity needs (the amount of electricity the system can provide to meet the highest level of aggregate customer demand at any given time) and energy needs (the number of kilowatt hours needed to serve customers). The relative balance between capacity and energy needs is another uncertainty facing the Company. The Company's strategy to quickly site SCCTs (to provide peaking), with sufficient land to be able to convert them later to CCCTs (to provide energy) can mitigate the potential costs of this uncertainty.

PacifiCorp is currently in dynamic balance — i.e., its level of supply is comfortably close to the level of energy needs. The Company is committed to maintaining that balance, despite the uncertainties of load growth, resource costs and availability, and other external factors.

The Company's strategy includes three approaches:

- **Acquire "low-regret" resources**. These are resources that are beneficial regardless of the level of load growth, such as some demand-side resources and combustion turbines (particularly simple cycle units in the short term);
- **Emphasize resource diversity.** Including demand-side resources, the lowest-cost renewables, and gas-fired resources in its new resource mix improves the diversity of the Company's system.
- **Assure flexibility.** Acquire resources that have short lead times or can be optioned or made adjustable in terms of timing.

OTHER FINDINGS

The illustrative plans show how PacifiCorp would implement its strategy to acquire the lowest cost resources first, and postpone the acquisition of high-cost resources as long as possible. The plans also indicate the following general patterns for each resource category:

Demand-Side Resources

Because the real levelized cost of a substantial amount of demand-side resources is less than the real levelized cost of the supply-side resources, all of the plans call for acquiring the full amount of cost effective DSR available.

Renewable Resources

All of the resource plans include an initial level of renewable projects, largely because of the Company's new environmental goal.

The initial renewable projects and anticipated additions over the planning horizon are an appropriate amount unless gas prices increase significantly, the cost of renewables declines significantly, or a more specific national policy develops regarding appropriate actions to reduce CO_2 emissions. In those exceptional cases, more renewable resources would be needed than initially called for.

Renewable resources can be added to PacifiCorp's resource base in small increments with relatively short lead times using a variety of fuels.

The Company is putting a strong emphasis on making sure its renewable resources are cost effective, in order to minimize price impacts on customers. The long-run success of these efforts will depend on whether the benefits from renewable resources justify their costs.

Peaking Resources

The illustrative plans reflect the Company's recognition that peaking as well as energy needs must be considered in making resource decisions. RAMPP-1 focused mainly on energy needs. RAMPP-2 also considers the contribution of each resource to capacity or peaking needs

Simple cycle combustion turbines (SCCTs) are well suited to meeting peaking requirements (i.e., to provide the maximum amount of electricity needed to serve customers at any given time).

The amount of SCCTs the Company will eventually need will depend on the level of load growth, and on the other resources that are added to the system. Some resource choices (for example renewables) can require more peaking capability. Other resource choices (for example combined cycle combustion turbines) require less peaking capability, because they provide capacity which can be assured to be available when the system needs it.

The resource plans consistently call for adding SCCTs to the system in the mid-1990s, suggesting that the Company should immediately pursue siting several hundred megawatts of SCCTs.

In addition, the Company plans to investigate pumped storage as a peaking option.

Cogeneration Resources

Cogeneration is included in all of the resource plans except the plan for low load growth. In all other cases, from 160 MWa to 840 MWa of cogeneration would be added by 2011, and, in most cases, the amount of cogeneration included in the plan is 330 MWa by 2011. Many of the resource plans call for beginning to acquire cogeneration in 1995. Therefore, it is timely for the Company to be pursuing cogeneration agreements with appropriate customers.

Gas-Fired Resources

The future price of gas will be critical in determining the actual timing and amount of gas-fired resources (including cogeneration, simple cycle combustion turbines and combined cycle combustion turbines) that are added to the system.

Higher gas prices can have a dramatic effect on the cost competitiveness of gas-fired resources. There is also uncertainty over the availability of adequate transportation to move the gas from production fields in Canada, Wyoming or New Mexico to the site of the gas-fired resource. If the Company is faced with higher-than-expected gas prices, it will be forced to rely more on renewable resources and turn sooner to coal resources.

Coal Resources

Most of the resource plans call for construction of a new coal plant by the year 2011. The earliest date in any of the forecast plans for bringing a new coal plant on line is 2001. With a lead time of seven years, a decision would not have to be made until 1994 at the earliest, and most likely later.

A construction decision will depend on the rate of load growth that occurs, the costs of alternative resources, and environmental considerations. By the time a decision is needed, more information will be available on all of these factors. Preliminary siting work can shorten the lead time and provide the Company with greater flexibility.

WHERE DO WE GO FROM HERE?

The development of RAMPP-2 resulted in a new action plan for PacifiCorp for 1992 and 1993. That action plan calls for the Company to:

In Demand-Side Activities and Renewables

- Continue to increase the amount of demand-side resources with current programs. Achieve 27 average megawatts of savings by 1994, and work over the next two years to accelerate the ramping up of demand-side programs so 170 MWa are achieved by 1996.
- Determine actions needed in 1992 and 1993 to have 125 megawatts of wind capacity (40 MW effective capacity) operating by 1996-97, and pursue those actions.
- Sign confidentiality agreements for one or more potential sites to analyze the feasibility of getting 50 MW of geothermal capacity on line by 1998.
- Determine the cost and performance of utility-scale solar energy resources through participation in the Solar II demonstration project.

In Peaking Resources

- Initiate siting, permitting and procurement for up to 450 MW of simple cycle combustion turbines.
- Implement the decision to acquire 150 MW of peaking resources in Arizona Public Service Company's area.
- Identify at least one potential pumped storage site and determine the feasibility and cost effectiveness of the technology.

In Cogeneration

- Sign intent agreements and pursue contract negotiations with industrial customers to have up to 300 MWa of cogeneration on line by 1997.

In Efficiency Improvements

- Identify where transmission upgrades could enhance resources and proceed where such upgrades are cost effective.

- Continue to implement system efficiency improvements as identified in RAMPP-1 and included in the existing system for RAMPP-2.

In Getting Ready for RAMPP-3

- Explore new or expanded modeling solutions for RAMPP-3 to more definitively address capacity and transmission limitations.

RAMPP-3 work will begin immediately so that a new 20-year resource plan can be completed, along with a new action plan for 1994 and 1995.

HOW TO GET A COPY OF THE REPORT

If you would like a copy of the 170-page RAMPP-2 Report, *Balanced Planning for Growth,* you may call (503) 464-5620. An additional 700 pages in four appendices are also available. They are: Forecasts, Demand Side Resources, Supply Side Resources, and Results. You may also request any or all of the appendices.

BALANCED PLANNING FOR GROWTH

Resource and Market Planning Program
RAMPP - 2

Ken Powell

May 14, 1992

PACIFICORP

PacifiCorp RAMPP-2 Report

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TABLES

BACKGROUND

This report summarizes PacifiCorp's second Resource and Market Planning Program (RAMPP-2). It is intended to serve two key purposes:

1) To describe the framework PacifiCorp will use in managing the balance between power supply and demand, RAMPP provides a long-range plan to guide the Company in evaluating resource and market decisions; and

2) To comply with regulatory commission requirements for integrated resource planning.

The Company's Resource and Market Planning Program is broader in scope and purpose than "least cost planning." Integrated resource planning considers both resource and market conditions in developing guidelines for evaluating resource alternatives in the future. Planning does not require premature decision-making, but it can provide general parameters to help guide ongoing decisions.

This document details PacifiCorp's most current planning information. It describes the assumptions, strategies and principles that will guide future supply and demand decisions. RAMPP-2 evaluates alternative resource strategies under a variety of future conditions. By using a process rather than following a specific plan, the Company retains the flexibility it needs to respond to changing conditions.

This chapter provides a brief overview of the near-term actions the Company will take, based on the RAMPP-2 planning framework and results. The chapter also describes the general context for RAMPP-2, including major developments since RAMPP-1; the Company's goals, commitments, and planning principles; LCP requirements; and the public process.

ENVIRONMENTAL GOAL AND ACTION PLAN

The Company's strategic plan for 1992 includes, for the first time, a specific environmental goal. It calls for the company to:

> "Continue to improve the management of our business operations as they affect natural resources and the environment. Seek new ways to expand Company programs that benefit the environment, while balancing the interests of customers and shareholders."

This environmental goal has guided the RAMPP-2 process, and its impact can be seen in the resulting action plan. The new goal includes challenging, measurable targets for energy efficiency programs and cost-effective renewable resources. RAMPP-1 considered external costs in its analyses; RAMPP-2 has been guided by a stronger emphasis on actions that benefit the environment. This direct link between the Company's strategic plan and the development of the integrated resource plan can be seen in an accelerated demand side resource DSR program and pilot renewable projects.

The goal calls for the Company to:

- Help customers achieve annual energy efficiency savings of 170 MWa by the end of 1996, compared to the RAMPP-1 medium forecast target of 91 MWa by the end of 1996. The 170 MWa enables the Company to achieve savings consistent with its proportional share of the Northwest Power Planning Council's regional targets.

- Begin staged development of renewable resources -- targeting 50 megawatts by 1996, and 200 average megawatts by 2001 if cost-effective. These targets can be compared to the RAMPP-1 action plan, which only called for review of the adequacy of information on potential renewable resources, and potential development after the year 2000.

- Determine the cost and performance of utility-scale solar energy resources through participation in the Solar II demonstration project.

- Investigate and test strategies to offset future increases in carbon dioxide emissions.

- Work cooperatively to formulate innovative regulatory measures to avoid regulatory impediments to the Company's pursuit of accelerated energy efficiency and renewable resources and air quality improvements.

RAMPP-2 resulted in a new action plan for PacifiCorp for 1992 and 1993. These actions position the Company to have the flexibility needed to meet the range of possible future resource requirements throughout the 1990s.

In the areas of DSR activities and renewable resources (wind, geothermal, and solar), the Company plans to take early action. The action plan aims to achieve 27 MWa of demand side savings by the end of 1993, and take the necessary actions in the next two years to accelerate its DSR programs to achieve by 1996 the 170 MWa targeted in the environmental goal. The ramp-up rates for DSR savings are 56 MWa by 1994, 100 MWa by 1995, and 170 MWa by 1996.

In the area of wind power, the Company will determine and pursue the actions needed in 1992 and 1993 to have 125 MW of wind capacity (40 MW effective capacity) operating by 1996-97. For geothermal, PacifiCorp will analyze the feasibility of bringing 50 MW of geothermal capacity on line by 1998. As for solar activities, the Company will participate in the Solar II demonstration project.

In the area of peaking resources (meeting customers' needs for maximum power whenever it is needed), PacifiCorp will initiate siting, permitting, and procurement for up to 450 MW of simple-cycle combustion turbines; acquire 150 MW of peaking resources in Arizona Public Service Company's area; and explore possibilities for pumped storage.

The Company will sign intent agreements and pursue contract negotiations with industrial customers to bring up to 300 MWa of cogeneration on line by 1997.

In the area of efficiency improvements, the Company will identify where transmission upgrades could enhance resources and proceed where such upgrades are cost-effective. It will also continue to implement cost effective system efficiency improvements.

In sum, PacifiCorp has identified a broad portfolio of resource options which it can bring on-line to provide electric service to customers at competitive prices. Due to strong economic growth in the late 1980s, the Company expects it will need more resources than indicated in its first least cost plan.

KEY PRINCIPLES REFLECTED IN RAMPP

PacifiCorp uses eight key principles to manage power supply and demand. These same principles are used in the evaluation of new resource alternatives. Balanced planning results when resource plans are developed and evaluated using all of the eight principles.

1. **Minimizing cost and retail price impact**
2. **Reliable service**
3. **Efficiency**
4. **Environmental responsibility**
5. **Flexibility**
6. **Diversity**
7. **Dynamic balance**
8. **Innovation**

Minimizing cost and retail price impact is the first principle of least cost planning. It is also consistent with the Company's strategic goal to keep prices to customers as low as possible.

Reliable service is the primary goal of the Company's customer service. Electricity is less a commodity than a service; it provides heat, light, industrial processes, etc.

Efficiency is of paramount importance to the Company's resource planning. It is critical for stabilizing or reducing electricity prices. Efficiency efforts include efficient operation of the Company's existing system, an efficient fit with other resource providers, and greater efficiency in the way customers use electricity. Efficiency improvements have helped the Company obtain substantially more power from the existing system. The Company also has put a renewed emphasis on efficient transmission and distribution. And it has pursued arrangements with other utilities to capture joint system efficiencies.

The Company is committed to helping customers use energy more efficiently and cost-effectively. During a time of sufficient resources, the Company has been focusing on building capability and capturing lost opportunities.

In 1990, the Company began demonstrating the energy service charge concept -- a unique way for participating customers to fund energy efficiency measures. The energy service charge is designed so the customer who directly benefits from the efficiency measures pays most of the cost, rather than the Company spreading the cost among all customers. The Company funds the measures up front, and customers repay the Company from their energy savings in the form of a separate charge on their monthly bill.

Environmental responsibility means the Company continues to improve the management of its business operations as they affect natural resources and the environment. The new environmental goal is the most recent evidence of the Company's commitment to preserving the natural environment to assure the long-term health and economic vitality of the communities and regions served by the Company. This has also been demonstrated by PacifiCorp's national award-winning resource management programs, its wildlife protection activities, its program of internal environmental audits, its pioneering investments in plant emissions controls and cooling systems, and its efforts to achieve a balanced solution for the preservation of Pacific Northwest salmon. The Company also integrates into its resource planning a consideration of environmental impacts.

Flexibility means the Company wants to be able to employ a diversity of different resource options as needed to respond to changing circumstances. Flexibility is the ability to change course without major impacts. The Company maintains flexibility by using the RAMPP process to guide resource and market decisions as conditions change and opportunities arise, and by including resource options that are available in small amounts, have short lead times, and low capital cost. Although some resource actions, such as construction of a power plant, can require more than 10 years' lead time, most decisions do not need to be made at the outset of a 20-year-plan. The Company maintains more flexibility by delaying commitments as long as possible.

A number of examples illustrate how the Company seeks to maintain this flexibility. The Company attempts to negotiate arrangements which specifically preserve and enhance its future ability to respond to uncertain future conditions. One example is the way in which PacifiCorp negotiated its option to purchase power from Bonneville under the Entitlement Agreement. PacifiCorp was the only utility among those negotiating with BPA that included in its contract a right to delay exercising the contract until 1997.

Another example is the way PacifiCorp preserved its option to repower the Gadsby plant. By keeping Gadsby, the Company was able to bring on a relatively inexpensive resource with the capability to meet peak loads very cost-effectively. Recently, the Company spent a nominal amount to refurbish Gadsby 3 so that it was ready to generate power, and signed a short-term fuel contract for natural gas. In addition, the Company is prepared to activate Units 1 and 2 as needed. To be able to use natural gas in the Gadsby units 1 and 2 in the future, the Company has investigated the acquisition and transportation of natural gas.

A third example comes from PacifiCorp's recent transactions with Arizona Public Service. The Company negotiated the right to purchase 125 MWa of energy each year for the life of the contract. Under that arrangement, APS is required to offer up to 125 MWa, but the Company has the option to either purchase it or not, at a price that is fixed by the contract and escalates over time.

Diversity means the Company does not want to "put all its eggs in one basket"; that is, rely totally on one or two resource technologies or options. Diversity is one way of hedging risk to the Company and its customers. The Company recognizes the uncertainties associated with the costs of various resources and fuels, and wants to maintain all resource options that may be needed in the future.

PacifiCorp also tries to identify opportunities to achieve diversity in its merger and acquisition activity. The merger with Utah Power & Light is the prime example of taking advantage of system diversities, not only in loads but also in resources and geography. The merger created approximately 340 MW of new resources available to the merged company through seasonal diversities. Another example is the Arizona Public Service Company arrangement. PacifiCorp acquired the Cholla-4 coal-fired unit and will resell during the summer a significant amount of power to APS. The arrangement is like a seasonal exchange: it maximizes the benefits of diversity between the two companies.

Dynamic balance refers to the economically efficient balance between loads and resources. No utility system is static; loads are varying constantly, resource capability also varies, and the Company must provide for an uncertain future. In the short term, the balance between loads and resources can be affected by variations in temperature, rainfall, and forced outages at the Company's generating facilities. Longer term variations in the balance between loads and resources can be affected by economic conditions, environmental concerns, technological changes, competition, fuel prices and changes in regulation and in the utility industry.

Between the two extremes of power surplus and deficit is a large gray area, where the criteria which are used to judge resource adequacy are more economic, strategic and subjective. A substantial surplus may leave some generating resources idle or under-used and impose unnecessary fixed costs. At the other extreme, a utility with insufficient resources risks system disruptions, deteriorating customer service and the need to purchase at the mercy of the marketplace to fill immediate needs.

One way the Company maintains a dynamic balance between loads and resources is through the wholesale market. Both sales and purchases can be arranged for as short a time as one hour or through contractual arrangements for as long as several years. Long term wholesale sales, ranging from one year and longer, are useful in providing economic benefits to retail customers while mitigating the risk of future uncertainties of both resource price and availability.

PacifiCorp believes that the current regional and western United States surplus energy situation will be relatively short-lived. When the energy surplus starts to dwindle, any utility with a modest surplus will be in a stronger position to negotiate for acquiring additional resources for the future. If, instead, a utility is in critical need of new resources, its negotiating position will be weak, and it will likely be forced to pay more for future resources. Maintaining a 2-3 year surplus can help PacifiCorp negotiate for future resources from a position of strength.

Innovation in resource management is central to PacifiCorp's style and approach. The Utah/Pacific merger provides an excellent example: Through this creative approach to managing power supply costs, the Company acquired approximately 340 megawatts of additional resources, due to seasonal diversity between the two power systems. The Company pursues flexible wholesale transactions which provide benefits to customers. The Company has been innovative in its recent work to derive more from the existing system through operating efficiencies and improved maintenance practices. Other innovations include investment in Solar II, an experimental project to test the viability of solar with storage, and the encouragement of ground source heat pumps for our customers. The Company carefully tracks new technology developments which could benefit customers.

CHANGES SINCE RAMPP-1

RAMPP-1 was completed during 1989, the first year of operation for the system that was created by the Pacific Power - Utah Power merger. RAMPP-2 is based on two additional years of experience operating the merged system, and a better understanding of the unique planning requirements for the merged system. The focus in RAMPP-1 was on meeting energy needs: that is, providing the kilowatt hours (kWhs) needed by the Company. The RAMPP-2 planning effort has paid closer attention to emerging capacity needs as well. Since RAMPP-1 was published, PacifiCorp has also developed a greater understanding of the diversity of DSR programs that are suitable for a more diverse customer base. For example, the commercial and industrial DSR supply curves were completely re-estimated based on new computer simulations for RAMPP-2. The simulations were extended to estimate capacity savings for a variety of building types and climate zones, including those found in the Utah service areas.

Other key developments since RAMPP-1 include:

- **PacifiCorp established an environmental strategic goal.** Its influence on the RAMPP-2 process is discussed above.

- **Growth in electricity demand has been on the high side of the RAMPP-1 forecast range.** The RAMPP-1 report predicted a range of 0.5 percent annual average load growth over the next 20 years at the low end, 1.6 percent in the medium case, and 2.6 percent in the high case. Since that plan was published, actual electricity usage increased at a rate of 2.8 percent in 1990 and 1.2 percent in 1991, for an average of 2.0 percent. This is between the medium-high and high forecasts from RAMPP-1. The growth in winter and summer peaks over this same period was more erratic, but the general trend for growth in peak demand is consistent with energy growth in the RAMPP-1 high range.

- **PacifiCorp completed a series of multi-faceted agreements for resource acquisitions.** One was with Arizona Public Service Company (APS) for wholesale power sales, seasonal exchanges, transmission rights, and generation use and planning. The Company acquired 350 MW of generation resources from the transaction, with a partially offsetting power sale to APS. The APS agreements added to PacifiCorp's resource base, captured seasonal diversity efficiencies, and extended the length of time within which the Company will have sufficient existing resources to meet customer needs. In a separate transaction, PacifiCorp acquired 243 MW of the Colorado-Ute Electric Association generating plant. Under the agreement among PacifiCorp, Public Service Company of Colorado and Tri-State Generation and Transmission Association, the Company purchased a share of the facilities of the bankrupt Colorado-Ute, and acquired related transmission rights. PacifiCorp also entered into a 176 MW long-term system power sale to Public Service of Colorado and a seasonal exchange with Tri-State Generation & Transmission. Like the APS agreements, the Colorado-Ute transaction provides the Company with additional resources to meet customer needs.

- **Congress amended the Clean Air Act.** The impact of the Act's emission limits on PacifiCorp will be small compared to the impact on many Midwestern and Eastern utilities that burn high sulfur coal without emission control technology. PacifiCorp's generating plants burn low sulfur coal and most already have sulfur dioxide emission controls. The Company has sufficient SO2 emissions allowances to operate its system effectively and continue to grow as needed. PacifiCorp has already made major construction expenditures at many of its plants to reduce SO2 emissions. Some additional control actions may be necessary. Since the Act does not mandate the use of a particular emission reduction technology, PacifiCorp will have the flexibility to select the most cost-effective methods for reducing emissions.

All of these recent developments have been included in the preparation of RAMPP-2.

COMPANY GOALS AND COMMITMENTS

PacifiCorp serves 1.2 million retail customers in seven states: Oregon, Washington, Utah, California, Idaho, Wyoming and Montana. Its electric utility operations approximately doubled in size through the 1989 merger of Pacific Power and Utah Power. This transaction was the largest successful electric utility merger in 50 years. The merger was a dramatic demonstration of the company's commitment to:

- Grow in ways that benefit both customers and shareholders;
- Pursue opportunities to capture the efficiencies available through regional diversities;
- Stabilize prices; and
- Explore new ideas to make the Company more competitive.

Managed growth continues to be a priority for PacifiCorp. The Company believes that carefully planned and well-managed growth results in more efficient service and prices for customers and an opportunity for shareholders to earn a reasonable return on their investment. The goal also reflects the Company's recognition that electric energy services play an important role in improving the economic vitality of the communities in PacifiCorp's service areas.

The goal of managed growth is fundamental to PacifiCorp's strategic, business and financial plans. The Company has set earnings growth goals because, as an investor-owned corporation, it must meet the reasonable expectations of its investors to successfully acquire financing in the competitive capital markets. It has also established goals for customer service, continuous productivity improvements, and the environment.

RAMPP-2 strengthens the link between the company's financial planning and resource planning. PacifiCorp has targeted increases in earnings per share of an average of 4 percent per year through 1996 as part of its strategic goal for growth. The Company's strategic goals are established yearly and are part of a dynamic evaluation and interchange among management regarding Company, region, and national economics, environmental public policy and other significant trends.

What are the power supply implications of a strategy with a strong financial growth objective? The Company's strategy relies on no single source of growth. Rather, expanded offerings of energy services, economic growth in the communities served by the Company, low cost acquisitions, and competitive wholesale activities all contribute to meeting the growth goal. Each of these areas has implications for the supply/demand balance of the Company, but none of them leads inexorably to a major new construction program for central station generation. The Company has identified a variety of resource alternatives available at reasonable costs to manage supply and demand. These can be employed to manage an efficient balance between supply and demand and to manage price stability. To illustrate: From 1985 through 1991, the Company added about 1,200 average megawatts of energy to its resource base. Almost 500 MWa of that came from Blundell, Cholla, Colstrip, and Gadsby. Purchased power accounted for 170 MWa, and thermal efficiencies and improvements accounted for about 500 MWa.

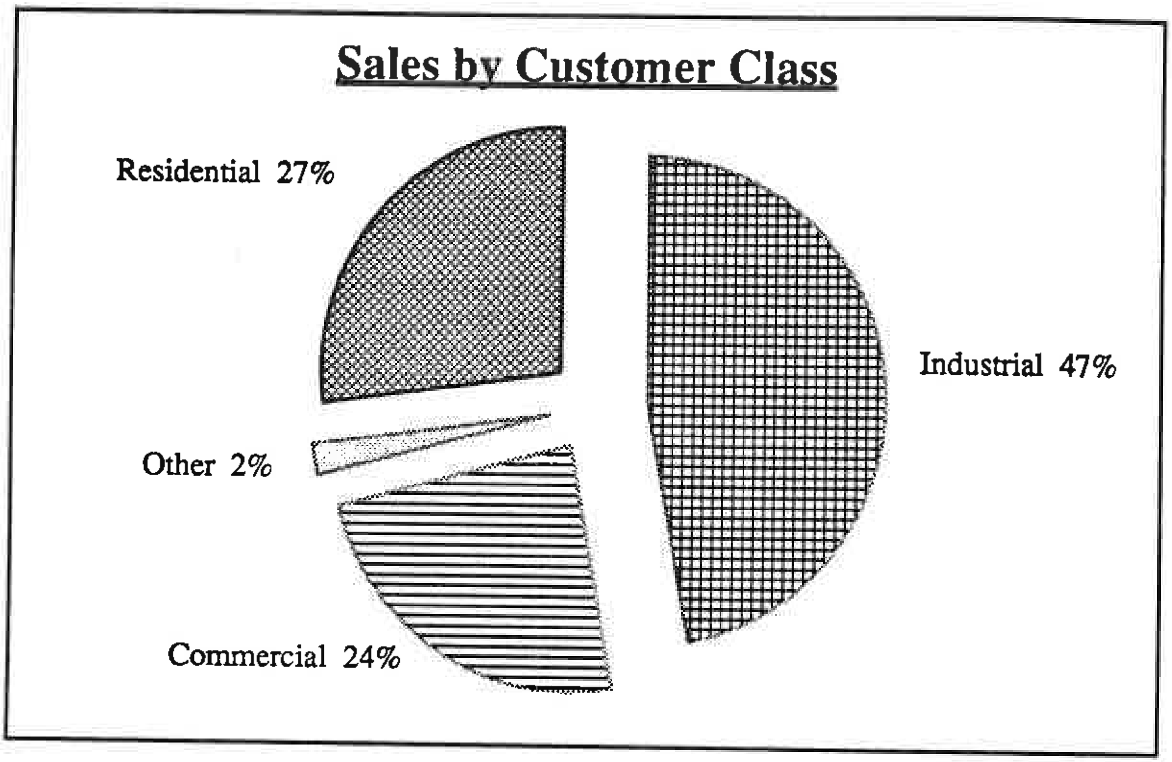
The Company believes the primary planning issue is not <u>when</u> the regional power surplus will end, but <u>how</u> PacifiCorp will manage supply and demand by deploying the most efficient demand side and generating alternatives.

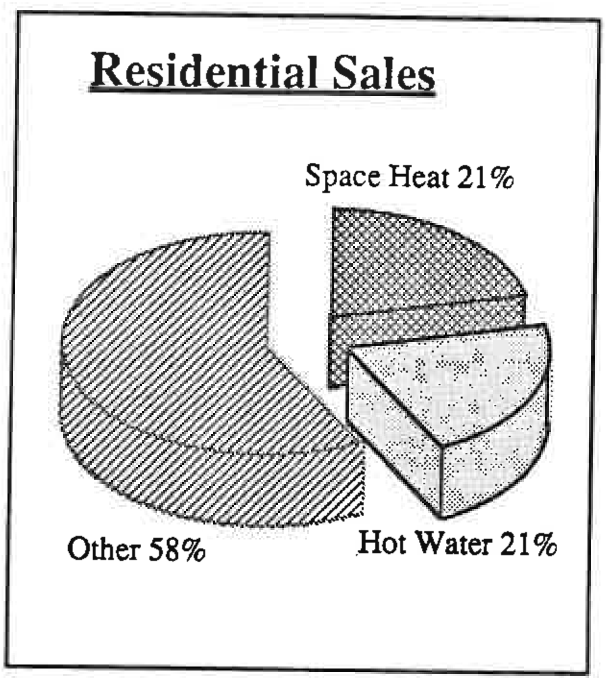
The mission of PacifiCorp is "to satisfy the electric energy services wants and needs of customers with electricity, energy efficiency and other products and services that add value to electric energy." Customer service is the consistent theme through all of the company's energy services activities. In some cases, "meeting customer needs" means improving customer productivity with additional energy efficient applications; in other cases, it means improving customer energy efficiency. All of PacifiCorp's' energy services activities emphasize the efficient use of electricity.

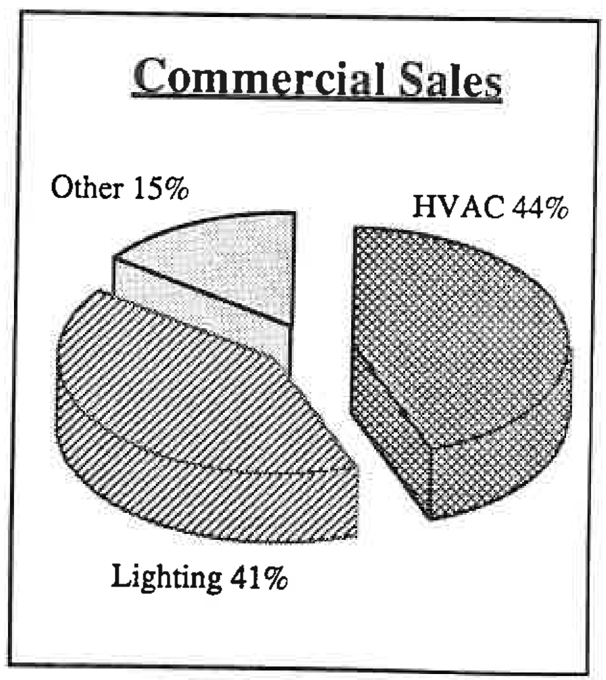
The company's management objective is to be a competitive, low-cost provider of a range of energy services. Several years ago, PacifiCorp made a commitment to customers and regulators to stabilize its prices through efficiencies captured both internally and through merger and acquisition activity. The Company has not only kept that commitment, which extends through 1992, but since May of 1987 all jurisdictions have seen either no price increases or price reductions.

An overview of PacifiCorp retail sales is illustrated in graph 1-1. The company's largest concentration of sales is in the industrial sector at 47 percent, followed by residential (27 percent), commercial (24 percent), and other (2 percent). The residential and commercial sectors are further divided by major end uses. The industrial sector is composed of a large number of end uses which do not lend themselves to a few categories. Residential primary end uses are space heat and water heat. Commercial primary end uses are lighting and HVAC (heating, ventilating, and air conditioning).

PacifiCorp RAMPP 2
Sales Overview by Class and End Use
Graph 1-1







LCP REQUIREMENTS

This report, together with the supporting technical documentation, is intended to comply with regulatory commission requirements for least cost planning. Montana and Utah are developing guidelines, and the Oregon and Washington regulatory commissions have already required that utilities prepare and submit a plan every two years that:

- Examines a range of forecasts for electricity demand;
- Considers all feasible alternatives for balancing resource supply with electricity demand;
- Assesses supply and demand alternatives in a consistent manner;
- Assesses possible external cost impacts as part of its evaluation of resource alternatives;
- Describes a credible long-range plan for balancing supply and demand and related uncertainties, and a short-range set of actions consistent with that long-range plan; and
- Has been prepared with substantial public involvement.

Overall, the commissions support least cost planning as a way to help utilities: 1) conduct their planning in an open manner with public involvement, and 2) inform the commissions on the process and principles the utility is following before it proposes specific actions.

PacifiCorp's understanding of the Commissions' goal is to meet customer needs at the lowest cost to the utility and its customers, and consistent with the long-run public interest. Whether this means minimizing revenue requirement or minimizing prices need not be a conflict. The Company's decision rules are based on acquiring first the lowest cost resources. And, for most resources, revenue requirement and price impacts are in the same direction. The exception to this comes with the acquisition of DSRs. The level of DSRs in the Company's plan is consistent with achievable ramp-up rates for cost-effective DSRs when additional resources are needed.

PUBLIC PROCESS

The RAMPP-2 Advisory Group (RAG) was an active participant in the development of this, the Company's second least cost plan. Representatives attended from public agencies and private groups.

Eleven all-day meetings were held with the RAG group. Before each meeting, a mailing was sent to all participants for their review prior to presentation at the meetings. The meetings then provided an opportunity for the participants to contribute their comments and concerns about the work in progress. Through this process, issues were raised and discussed as the plan was developed, and the group's input could be incorporated into the plan.

Subgroups of the RAG group also met to more fully discuss specific topics. Those groups addressed:

Demand Side Resources (3 meetings)
Forecasting (2 meetings)
Resource Cost Effectiveness (1 meeting)
External Costs (2 meetings)

The RAMPP process within the Company involves several departments. The primary ones are Integrated Resource Planning, Power Planning, Demand Side Planning, Forecasting, Financial Planning, Pricing & Regulatory Affairs, Economic Regulation, and Government Affairs. Regular internal task force meetings are held to discuss work progress, issues, and agenda items for the RAG meetings. Frequent discussions occur with other personnel in the Company when additional information or decisions are required which affect those areas, such as distribution or transmission engineering, coal contracts, or wholesale contracts. When issues develop that require officer-level input, a presentation is made to the Management Council, or a smaller meeting is held with a few officers whose areas have some responsibility for the RAMPP process.

ORGANIZATION OF THE REPORT

This document is organized according to the sequence for preparing RAMPP-2. It first identifies futures, then a portfolio of resources. It then describes the illustrative plans that were developed, summarizes the implications for major issues, and provides an action plan.

Chapter 2: Futures identifies the three types of futures used in RAMPP-2: forecasts, scenarios, and sensitivities. Forecasts define the range of possible future levels of growth in electricity consumption growth ("load levels"), based on various economic and demographic assumptions. Scenarios assume possible future occurrences that could have a major impact on the cost or availability of resources. Sensitivities are other factors that should be investigated for their potential impact on resource decisions. Included are environmental costs, other resource uncertainties, and other load growth uncertainties.

Chapter 3: Portfolio identifies the mix of resource alternatives available to the Company. Included are three categories of resources: existing system, demand side resources, and supply side resources. The Company evaluates each resource based on the eight principles described above.

Chapter 4: Illustrative plans have been developed for each of the identified futures. They illustrate how the Company would manage an efficient balance of resources to meet customers' future electric needs cost-effectively for each possible future. The plans are developed by balancing cost with the other seven principles discussed above. A key purpose of the illustrative plans is to test the flexibility and workability of RAMPP under varying conditions.

Chapter 5: Major Issues discusses key issues affecting the company's resource planning, including growth and price stability, uncertainty, environmental costs, renewable resources, and peak versus energy planning.

Chapter 6: Action Plan identifies the specific actions the Company has determined it must take in 1992 and 1993 to minimize future risks, and be ready for likely levels of load growth.

Chapter 7: Question and Answer provides a forum for a brief discussion of technical issues not developed elsewhere in the report.

Chapter 8: Conclusion summarizes the report and draws major conclusions.

Chapter 9: Glossary defines the various terms, acronyms, and titles used throughout the report and its tables.

Technical Appendix is provided as four separate documents: Forecasts, Demand Side Resources, Supply Side Resources, and Results.

POTENTIAL FUTURES

It's been said that the only thing constant in life is change. Along with that change comes uncertainty. The forecasts, scenarios, and sensitivities described in this chapter have been developed to help PacifiCorp prepare for an uncertain future.

The **forecasts** bound reasonable levels of future electricity consumption. They consider a number of economic and demographic possibilities, and the anticipated level of load growth. Four forecasts are developed to bound a reasonable range of possible electricity need.

The **scenarios** generally address possible changes that would affect the costs or availability resources which will be used to meet load growth. Four scenarios are provided.

The **sensitivities** address other uncertainties not considered in the forecasts and scenarios. Five sensitivities address external costs, six examine resource uncertainty beyond the scenarios, and seven examine the consequences of load growth uncertainty beyond the forecasts.

Taken together, the forecasts, scenarios, and sensitivities encompass 26 possible portraits of the future. They are intended to represent the range of futures for which the Company should prepare. By planning for this range of possibilities, the Company can minimize the risks posed by uncertainty.

POSSIBLE FUTURES: FORECASTS

In resource planning, the first question to be addressed is, "How much power will customers need in the future?" This section describes the methodology used to develop four load forecasts of customers' future electricity needs.

The RAMPP-2 process began with forecasts for every year from 1991 to 2011 based on 1990 actual data. Then, at the beginning of 1992, most of the 1991 actual data were available to revise the estimate for 1991. Forecasts are made for each of nine zones served by the Company: Oregon, California, Utah, Washington and Montana as well two zones each in Idaho and Wyoming. Idaho and Wyoming each have one geographic area served by Utah Power and another area served by Pacific Power.

The forecasting process can be thought of as a model that uses information "inputs" and produces forecast "outputs." A range of values for certain variables are put into the forecasting model to produce a range of forecasts. Events that have occurred since the forecasts were prepared may tend to skew the probabilities one direction or another. For example, load growth in the Northwest may be lower than forecast because of anticipated actions resulting from the Endangered Species Act. Other events may cause load growth to be higher. The range of forecasts used for RAMPP-2 is large enough to accommodate changes in load levels that might result from these recent events.

The information used for the forecast model includes economic and demographic variables (such as employment, population and income for that particular jurisdiction). The model also anticipates the electricity needed to run electrical equipment in that zone, based on historical information and other data. The output of the process is the company's range of electricity sales forecasts for each zone.

Four forecasts are made for each zone:

- High
- Medium high
- Medium low
- Low

For economy of presentation, the medium high load growth forecast will be referred to as MH, and the medium low load growth forecast will be referred to as ML. To develop the "high" forecast for a given zone, the high economic, demographic and other input factors are used. Similarly, the MH forecast uses medium high economic and demographic assumptions, and so on. The system wide forecast for each level (high, MH, ML and low) is the sum of the nine zone forecasts. For example, the "high" electricity sales forecast for all of PacifiCorp equals the sum of the "high" forecasts for all nine zones.

Unlimited combinations of economic and demographic conditions exist that make any of the forecasts between the MH and ML energy forecast very likely. Forecasts between the MH and high range, or between the ML and low range are less likely. A dramatic change in economic, demographic, or consumer choices and behaviors would be needed to produce a forecast that is above the high or below the low energy forecast.

Electricity price is an important component of the forecasting model. Electricity prices are assumed to increase slightly more than the rate of inflation in the high forecast case, and to increase less than the rate of inflation in the low forecast case. The MH and ML forecasts assume price increases at about the level of inflation. Price elasticity was not used to reduce the high forecast and increase the low forecast. That would have reduced the range of futures for planning. The Company believes that it is important to test the portfolio over a wider range of load growth.

Once the system wide forecasts for electricity sales have been determined, the Company considers system losses (i.e., the efficiency of getting electricity from the point of generation to the customer) before calculating how much energy must be generated to meet peak levels of electricity need. Historic load factors are used to develop the forecasts of peak usage for winter and summer.

The forecast methodology resulted in four forecasts with 20-year growth rates for energy of 0.5 percent in the low case, 1.7 percent in the ML case, 3.1 percent in the MH case, and 4.0 percent in the high case. The peak forecasts result in very similar growth rates for the four forecasts. The growth is forecast to be slightly higher in the early years than in the later years, and to be slightly higher for the Utah Division than for the Pacific Division.

Table 2-1 shows key information from the forecasts for energy, winter peak, and summer peak. For each of these three measures, it indicates the system level at the end of the planning period in 2011, the total added to the system, and the annual average additions. In the low case, 520 MWa are added over the 20 years, and the winter and summer peaks grow by 654 and 661 MW, respectively. In the MH case the system grows by 4030 MWa to 9453 MWa by 2011. In the high case, the system more than doubles. 5910 MWa are added over the 20 years, and the winter and summer peaks increase by 7808 and 7478 MW, respectively.

For each of the four forecasts, annual sales by customer class and state, and monthly peak and energy forecasts by state, are contained in the Load Forecast Technical Appendix. The methods used to develop these forecasts are summarized below and described in greater detail in the Technical Appendix.

Input: The Variables

Economic and demographic assumptions are two key factors in determining the forecasts. Absent other changes, usage of electricity usually increases as economic activity increases in the region. However, that parallel relationship can be distorted by changes in the price of electricity, the price and availability of competing fuels, changes in the nature of economic activity, the level of conservation and the rate at which buildings and energy-using appliances are replaced. All of these variables are factored into the forecasts.

The Company uses national economic and demographic assumptions from Data Resources (DRI), a national research Company. DRI provides three possible forecasts for the national economy (optimistic, current trend and pessimistic). Differing assumptions about regional economic growth are combined with these national assumptions to produce each of the four forecasts.

The third major factor in forecasting future electricity sales is anticipated consumer use: "What electrical appliances will customers want and how will they use them?" The Company predicts the level of use for each of its four customer segments: residential, commercial, industrial and "other."

Each customer segment uses electricity in specific ways; i.e., each has particular end uses for electricity. For example, residential customers use electricity primarily for space heating and water heating. Commercial customers mainly use electricity for lighting and HVAC. Industrial customers use it for processing.

To predict the overall level of future electricity use for any one customer segment, the Company looks at how the customers in that sector use electricity and how much electricity they use. Future usage depends on:

1) How many customers are currently equipped for each end use (the saturation level);

2) How many additional customers will be equipped for that end use in the future (the penetration level);

3) How much electricity is currently consumed (level of use) for that activity; and

4) How electricity consumption for that activity will change in the future.

PacifiCorp - RAMPP 2

Key Forecast Information

Table 2-1

Forecast	Energy Growth Rate	Total System MWa at 2011	Total Energy MWa Added	Annual Ave. Energy MWa Added	Total System Winter Peak at 2011	Total Winter Peak MW Added	Annual Ave. Winter Peak MW Added	Total System Summer Peak at 2011	Total Summer Peak MW Added	Annual Ave. Summer Peak MW Added
Low	0.5	5,595	520	26	7,241	654	33	6,801	661	33
Med-Low	1.7	7,040	1,912	96	9,194	2,463	123	8,642	2,365	118
Med-High	3.1	9,453	4,030	202	12,405	5,350	268	11,770	5,181	259
High	4.0	11,460	5,910	296	15,120	7,808	390	14,315	7,478	374

Residential Load

In the residential sector, the Company predicts the anticipated consumer usage for 14 end uses of electricity: space heat, water heat, electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs, well pumps and residual uses. Air conditioning can be central, window or evaporative (swamp cooler).

For each end use, the Company looks first at saturation levels (the number of customers equipped for that end use) and how those saturation levels may change with demographic and economic changes. The saturation level for each end use is estimated based on Company survey information. Then the Company determines the penetration level: given the economic and demographic future assumptions, how many new households are expected to adopt that end use in the future? In addition, how many houses which currently have that end use are being demolished? Historic information is used to estimate the demolition rate. Some appliances may be replaced several times before a home is demolished. The shorter lifetime of various appliances compared to the lifetime of a home is considered in determining the number of customers who use electricity for each end use.

The numbers of new and existing customers using electricity for a certain purpose are added together to determine the total number of customers for that end use.

The Company then looks at level of use. The projected level of kWh consumption for space and water heating in existing homes is based on historical information. The projections of kWhs needed for appliances are estimated based on historical data and accepted institutional, industry and engineering standards.

Two additional factors are considered in the projections of usage for space heating:

1) Availability of wood heat. In some parts of PacifiCorp's service territory (predominantly the Pacific Northwest), significant numbers of customers have both electric and wood heating equipment. The displacement of electric space heat by wood space heat is considered in projecting future consumption levels.

2) Model conservation or energy standards. If a state has enacted energy standards, or is expected to enact standards such as Oregon's Model Conservation Standards, the projected space heat usage for that state is adjusted. For states that have not enacted model conservation standards, the present energy standards are assumed.

The forecasting model assumes that most appliances will become more energy efficient over time, because of known changes in technology and government standards.

The model also includes an estimate of the level of conservation that might occur for each end use. The forecast of how much energy residential customers will need in the future considers how much conservation they will be performing on their own initiative. This level of other DSR acquisitions is different for each load forecast level.

The end result of all these calculations is the projected level of electricity usage expected from residential customers. This is the "residential forecast" used in developing the total system load forecast.

Commercial Load

Commercial usage is projected for each of 12 categories of commercial customers served by PacifiCorp. Those categories are: Communications/Utilities/Transportation; Food Stores; Retail Stores; Restaurants; Wholesale Trade; Lodging; Schools; Hospitals; Other Health Services; Offices; Services; and miscellaneous. Growth in employment reflects economic health and is the major determinant of how much commercial energy use increases. Changes in employment drive changes in square footage, which is a major driver of commercial energy requirements.

The Company forecasts, on a kWh usage per square foot basis, the level of usage for seven end uses: space heating, water heating, space cooling, ventilation, cooking, lighting and miscellaneous uses. Saturation and level of use are calculated for each end use; these numbers are then factored together to predict future usage for each commercial end use.

The saturation levels and usage per square foot for each of the commercial end uses have been estimated using data from commercial surveys, commercial customer consumption data, and engineering estimates. Usage per square foot for existing buildings is based on 1990 levels. Usage per square foot for new buildings has been estimated using engineering models and assuming current practices.

As with the residential sector, the forecasted usage for the commercial sector considers how much conservation commercial customers will be performing on their own initiative.

The result of these calculations is a forecast of the kWhs needed to serve commercial customers. That commercial forecast is used in developing the total system load forecast.

Industrial Load

PacifiCorp's industrial customers represent a large number of firms and industries. They are a heterogeneous mix of customers representing industries with widely divergent electricity consumption characteristics per unit of output. Accordingly, the industrial customer segment has been broken into 14 relatively homogeneous categories: Coal Mining; Oil & Natural Gas Exploration, Pumping, and Transportation; Non-Metallic Mineral Mining; Food Processing; Lumber and Wood Products; Paper and Allied Products; Chemicals and Allied Products; Petroleum Refining; Stone, Clay & Glass; Primary Metals; Electric Machinery; Transportation Equipment; a general manufacturing category; and other mining. The forecast for a given industrial segment is not broken down into end uses because industrial customers in each segment tend to use electricity in the same way, although individual plant processes may vary.

Since employment is a measure of general economic health, it is used as the foundation for the industrial energy forecasts. Historical relationships between industrial consumption and employment for each industrial category are reviewed for efficiency changes and then used to estimate electrical needs in the future.

As with the residential and commercial sectors, the forecasted usage for the industrial sector includes an estimate of the level of conservation that might occur. The forecast of how much energy industrial customers will need in the future considers how much conservation those customers will be performing on their own initiative.

These calculations produce a forecast of the kWhs needed to serve industrial customers. That forecast is the level of industrial load used in developing the total system load forecast.

Electricity usage for other smaller categories of customers (such as irrigation, highway lighting, street and area lighting, etc.) are forecast in a way similar to the industrial customers.

Output: The Forecasts

The low, ML, MH, and high load growth projections for the system are shown on the following pages.

The most probable future growth lies between the ML and MH forecasts. However, by broadening the range of forecasts to include higher and lower possibilities, the Company is able to achieve a 90 percent confidence level in its projections -- i.e., there is only a one in ten chance that the future electricity consumption will lie outside the bounds of the high and low forecasts.

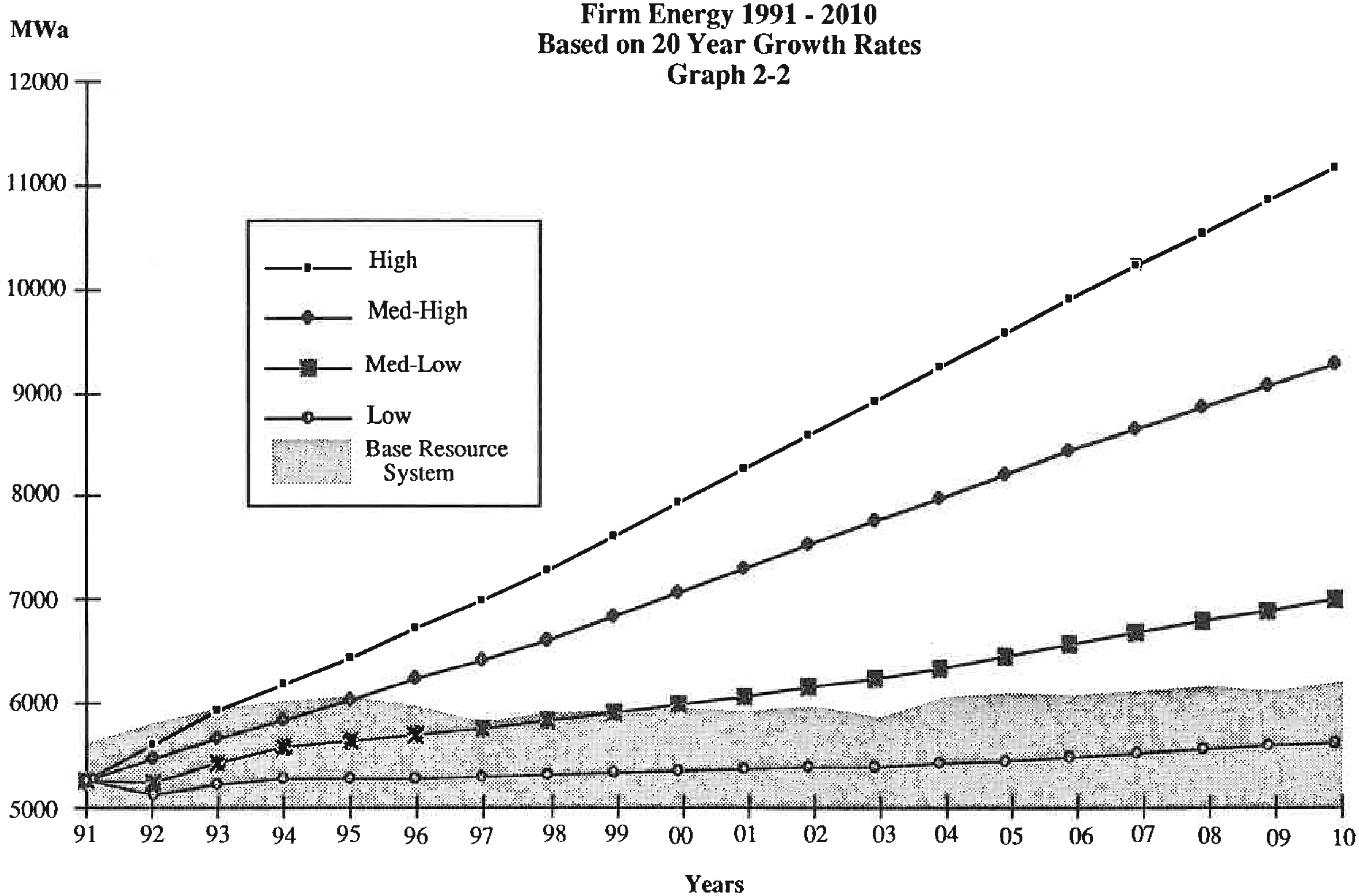
For each of the four categories (high, MH, ML and low), three pieces of information are forecast:

- Annual energy sales (how many kWhs the Company is expected to sell;
- Winter peak sales (the highest level of demand that would be needed during the winter months); and
- Summer peak sales (the highest level of demand that would be needed during the summer months).

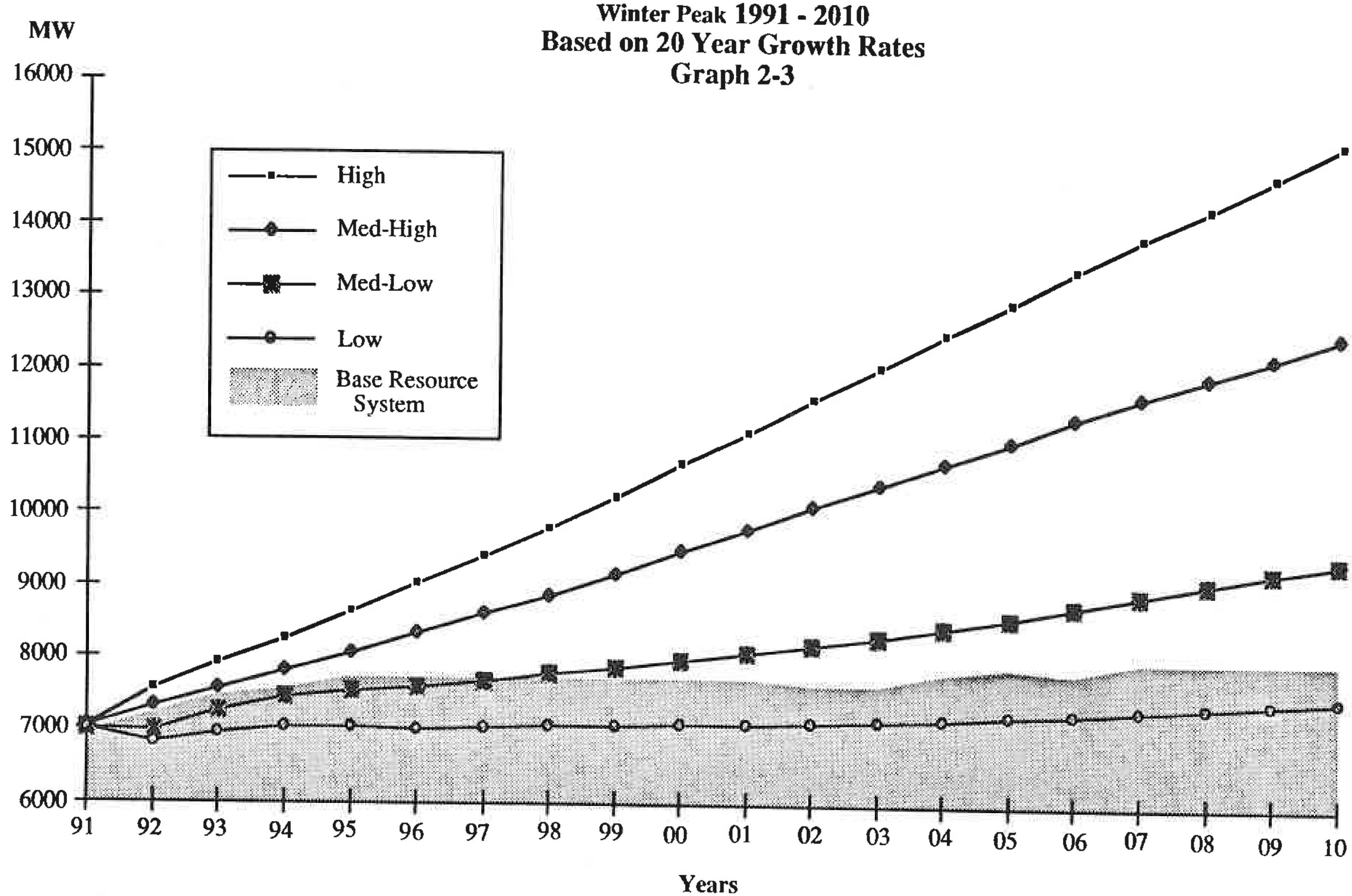
The annual forecasts are adjusted for system losses. Then, historic load factors are used to develop monthly peak forecasts. The historic load factors are based on three years of the merged Company coincidental peak data (the load for each state at the time the system peak occurs). Presently, the information needed to develop coincident load factors is available only at the state level. The Company is working to develop the information needed to calculate load factors for each class within each state. The load factors will be updated each year as more data becomes available, including the impact of future DSR programs.

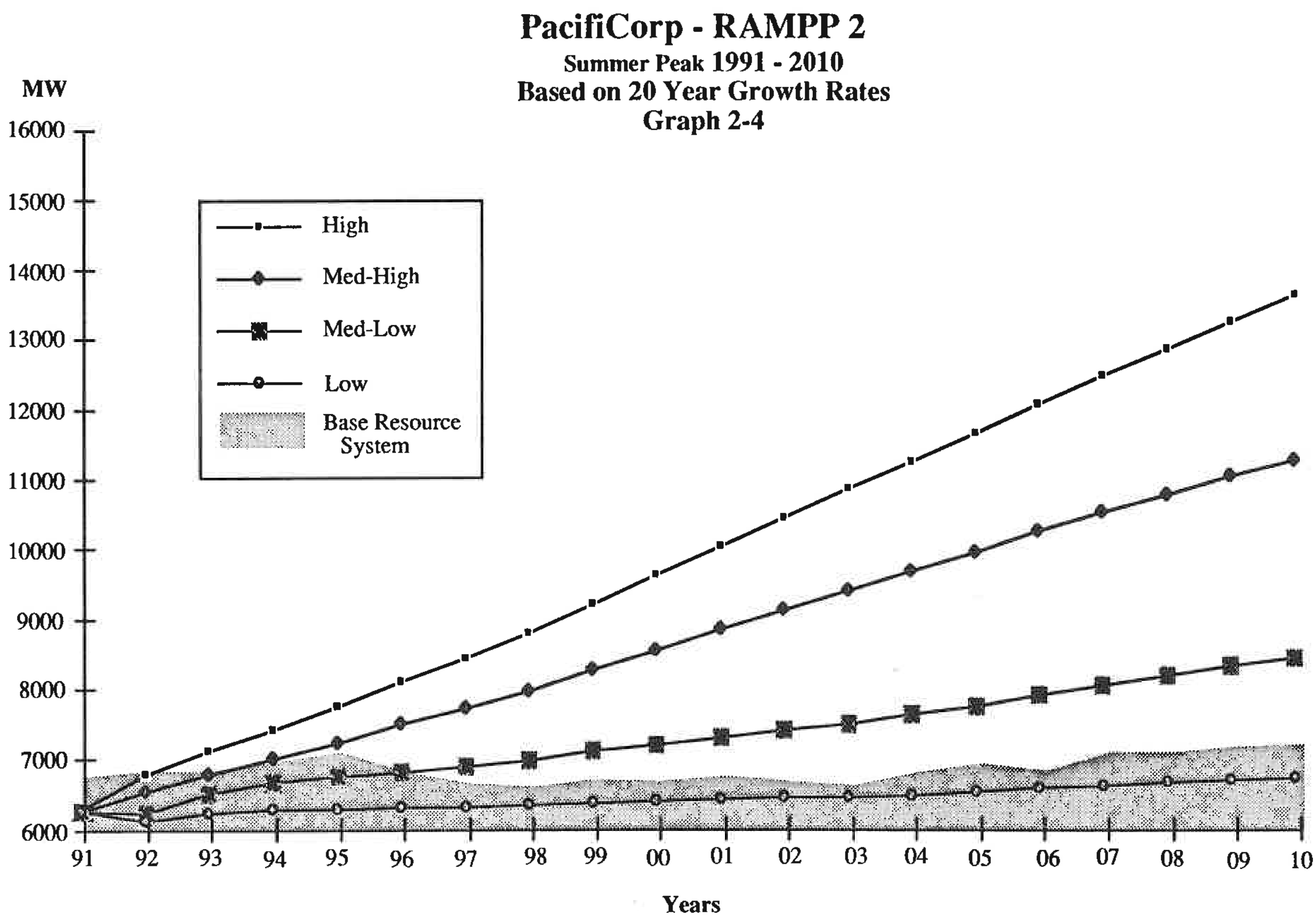
Graph 2-2 shows the four 20-year forecasts for energy. Graph 2-3 shows the results for winter peak, and Graph 2-4 shows the results for summer peak. Each one indicates the degree to which the forecast differs from the Company's existing system. In this context, the base resource system includes the system as it exists today, and known changes to it during the 20-year planning horizon.

PacifiCorp - RAMPP 2
Firm Energy 1991 - 2010
Based on 20 Year Growth Rates
Graph 2-2



PacifiCorp - RAMPP 2
Winter Peak 1991 - 2010
Based on 20 Year Growth Rates
Graph 2-3




PacifiCorp - RAMPP 2
Summer Peak 1991 - 2010
Based on 20 Year Growth Rates
Graph 2-4
MW
16000
15000
14000
13000
12000
11000
10000
9000
8000
7000
6000
High
Med-High
Med-Low
Low
Base Resource System
91
92
93
94
95
96
97
98
99
00
01
02
03
04
05
06
07
08
09
10
Years

POSSIBLE FUTURES: SCENARIOS

Although the forecasts cover about 90 percent of the possibilities for future load levels, they assume no major changes in the existing institutions and policies that affect power supplies. The scenarios are intended to help the Company plan its resource management in the event of a situation not encompassed by the range of the four forecasts.

The scenarios allow the Company to test the flexibility and adaptability of the resource portfolio. The implied question is: "If this major external event were to occur, would the Company's resource portfolio provide enough options and flexibility for PacifiCorp to respond with cost effective solutions?" The scenario analyses indicate the different type and timing of resource decisions under different conditions. The key is not whether the Company could respond, but how it would respond to minimize costs to the Company and price impacts on customers.

With the help of its RAMPP Advisory Group, the Company evaluated a long list of possible trends and events that would have a major effect on electricity supply and demand. Those trends and events were eventually narrowed to four major possibilities. This narrowed list was discussed with the RAG group, and modified. The final list of four scenarios was broadly supported by the group. The type of event modeled in one scenario could easily occur simultaneously with the type of event modeled in another scenario. However, in the interest of limiting the total number of futures, each with its own resource plan, the total was limited to four scenarios.

The first scenario -- electrification -- alters the level of load growth above the forecast for the high case. The other three scenarios use the MH forecast of loads, and alter either the existing system or the portfolio of resources available to meet future needs. To stay within a range of the most likely futures, the load growth level to use for the other three scenarios was narrowed to either the ML or the MH. The MH forecast was selected because the ML requires so few additional resources that the scenarios would cause very few resource changes, and the results would not be very useful. The four scenarios selected for analysis were:

1) Electrification.
2) Loss of resources.
3) High gas prices.
4) CO_2 tax.

Electrification

The Electrification scenario affects the level of load growth, but does not change resource costs or availability from those used in developing resource plans for the four forecasts. It assumes that major breakthroughs in the cost effectiveness and environmental benefits of using electricity in certain sectors could boost usage higher than the levels indicated by the high forecast. For example, some studies have suggested that increased use of electricity for some purposes can reduce emissions of air pollutants and CO_2. Higher electricity consumption might also result because electricity can increase energy efficiency or productivity in many applications.

Electrification could include changes in any of the following areas:

- Increased use of electricity in the industrial sector;
- Increased use of electric vehicles (EVs) in the residential and commercial sectors;
- Increased electricity use in the residential sector in the Northwest because of environmental regulations on wood stoves;
- Indoor air quality concerns leading to more ventilation equipment; and
- A growing percentage of new energy customers using high efficiency electric heat and air conditioning rather than other fuels.

What might cause the electrification scenario to come about?

Industrial customers could adopt more electrotechnology to increase productivity and efficiency. The Company's customer service philosophy promotes electrotechnologies that offer such benefits to the customer. Some industrial customers might turn to electrification as a way to reduce pollution. Increased use in the industrial sector could add as much as two million megawatt hours to the company's load levels within five years, and five million megawatt hours by the end of the 20-year planning horizon.

Increased use of electric vehicles (EVs) could result from legal mandates to reduce pollution in high traffic areas and lessen American dependence on foreign oil. The total life cycle operating and capital costs for EVs are now only about four percent higher than the comparable costs of traditional gasoline powered vehicles. The Electric Power Research Institute (EPRI) estimates there will be seven million on American roads by 2005, with about two million electric service vans in use. EPRI estimates that each will use about as much electricity as one new residential customer -- an average of 30 kWh per day or 10 MWh per year per vehicle. In PacifiCorp's service area, most would likely be in the Salt Lake City area because that is the largest urban center served by the Company.

The major market for electric vehicles is California, where legislation has been passed requiring 10 percent of all cars sold in the state by the year 2000 to be non-polluting. If the market there grows significantly, electric utilities in California would need to acquire additional power to meet the need. Some of that power could come from the wholesale market, creating increased wholesale sales opportunities for PacifiCorp.

Environmental restrictions on wood stoves could result from concerns about air quality. Wood stoves are used primarily in the Northwest. Such restrictions would prompt many wood stove users who also have electric heat to rely primarily on their electric heating equipment instead.

Higher efficiency standards and tighter building codes will lead to a greater need for air-to-air heat exchangers and other high efficiency ventilation equipment. At the same time, higher efficiency houses would reduce the amounts of electricity used for heating. These changes could make some gas line extensions uneconomic. Natural gas suppliers might decide that it is not cost effective to extend gas lines to these highly efficient structures, which would mean more new customers turning to electric heat.

Loss of Resources

Various regulatory or legislative changes could cause the Company to lose some of its resources. For example, the Company could lose access to, or flexibility in the operation of regional and Company owned hydroelectric facilities, due to concerns over the viability of certain fish populations.

The loss of resources scenario assumes fish concerns would affect both capacity and energy. For capacity, the assumptions were changed regarding PacifiCorp's contract with BPA for purchase of peaking capacity. The purchase is currently scheduled to be at 1100 MW in 1992, to increase by 100 MW per year until it reaches 1400 MW, and then to remain at that level throughout the planning horizon. The loss of resources scenario assumes the BPA capacity contract would be limited to 1100 MW throughout the planning horizon.

For energy, the assumption was changed regarding the size of the energy margin needed for prudent operations. If the Company were forced to rely less on its hydro resources for load shaping, more of its thermal resources would have energy available that could not be shaped, and would therefore be less usable. Therefore, the amount of energy capability above that required to serve loads would need to be increased. Most of the runs included a planning margin of a minimum of 150 MWa above the load forecast. That minimum margin was increased to 300 MWa for the loss of resources scenario.

High Gas Prices

This scenario is based on the assumption that natural gas prices are higher than in the other cases. In the base cases, gas prices begin at $1.65/mmbtu, escalate through 2011 at DRI's forecasted rate (9.94 percent nominal, 4.61 percent real), and at the rate of inflation (0 percent real) after 2011. Under a higher gas price assumption, prices would begin at $1.95/mmbtu, escalate through 2001 at DRI's forecasted rate, and continue to escalate through 2045 (the last year for the lifetime of any added resource) at 8.63 percent nominal, 3.36 percent real.

A large portion of future cost effective resources for the Company will be gas fired, for both peaking (SCCTs) and energy (CCCTs and cogeneration). Their cost competitiveness with other resource alternatives will depend on gas prices. Therefore, it is prudent to anticipate higher gas prices, and anticipate the resource changes that would need to be made to accommodate higher gas prices.

CO2 Tax

This scenario was developed to address the future risk of a CO2 tax on fossil fuels, which would arise from the current concerns about global warming. It assumes that a major national and international commitment is made to reduce carbon dioxide emissions. Various tax levels were discussed by the RAG group. A consensus was that $30/ton is an amount that is frequently discussed, and is large enough to make a difference in resource priorities. Therefore, this scenario assumes that a federal law is passed which taxes CO2 emissions at a rate of $30 per ton. This scenario increases the fuel cost of the new resource alternatives that rely on fossil fuels by $30/ton of CO2 emissions beginning in 1996, and escalates the tax each year thereafter at the rate of inflation. The added costs for coal generated power would likely cause some shifting in the priorities among the new resource options in the company's portfolio.

POSSIBLE FUTURES: SENSITIVITIES

Eighteen sensitivities were examined to investigate the potential impact on resource planning of other uncertainties, beyond those included in the scenarios.

Environmental Sensitivities

A group of four futures were examined which add external costs to the costs of resources available to the Company. Externalities are the impacts one activity (electric power generation) would have on other activities (primarily the environment and human health) that are not priced in the marketplace. PacifiCorp understands the growing concern among policy makers and the general public that the effects of environmental externalities need to be recognized in resource planning.

PacifiCorp, with the aid of its RAMPP Advisory Group, developed a range of costs for identified pollutants to be applied in sensitivity cases. Although the Company recognizes that these costs may have some impact on resource priorities, it does not believe any one of these cost levels is the appropriate one to use in resource planning. They are used in the analyses to provide illustrative information to the Commissions. Four cost levels were used, as follows:

	Level 1	Level 2	Level 3	Level 4
SO2	$1000/ton	$2000/ton	$2000/ton	$2000/ton
NOx	$ 100/ton	$4000/ton	$4000/ton	$4000/ton
TSP	$ 200/ton	$3000/ton	$3000/ton	$3000/ton
CO2	$ 5/ton	$ 0/ton	$ 10/ton	$ 30/ton

Four sensitivity cases were developed, each one using one of the four external cost levels. An additional sensitivity combined external cost uncertainty with gas price uncertainty, and assumes external costs at level three with the higher gas price assumptions used in the high gas price scenario. All five sensitivities used the MH forecast for projected load growth, and the same portfolio of resources as for the forecasts.

Other Uncertainties

The Company also examined a number of other uncertainties related to resource performance and cost. These used the MH forecast for projected load growth. Two sensitivities address renewable resources. One assumes that all renewable resources cost 20 percent less than they do in the other cases, and one restricts resource selections by removing coal and gas-fired resources (except for cogeneration and solar with gas back-up) from the portfolio. Two address the uncertainties associated with acquiring DSRs. One assumes that DSR acquisition is 30 percent higher, and another assumes it is 30 percent lower than the level assumed in the MH forecast plan. Two address resource uncertainty.

One assumes the Company's thermal power plants operate 10 percent less than they currently do. That sensitivity is intended to model the circumstance in which, for whatever reasons, the Company might be unable to keep its coal plants running at their current high operating availability. Another sensitivity assumes the Company uses average water conditions in its planning rather than critical water conditions, as in the other cases.

Load Growth Uncertainty

Load growth uncertainty is perhaps the most difficult uncertainty in resource planning. Introducing unexpected changes in load growth is one way to test the flexibility of different resource strategies. The Company tested load growth uncertainty with seven sensitivities. The first five assume that for the first seven years of the planning horizon, the Company expected one level of load growth, but experienced a different, actual level. After seven years, planning began assuming the actual level of load growth. In reality, the Company would respond sooner than seven years if actual load growth was different than expected. However, if a shorter time frame had been used for this analysis, the results would not have been as informative. The last two sensitivities assume load growth increases for a short time and then returns to a lower level. The cases tested were as follows:

1) ML load growth expected, low growth occurs;

2) ML growth expected, MH growth occurs;

3) MH growth expected, ML growth occurs;

4) MH growth expected, high growth occurs;

5) High growth expected, MH growth occurs;

6) MH growth expected, high growth occurs from 1992 through 1998, then MH occurs from 1999 through 2005 (while the Company expects continued high growth), then MH occurs as expected from 2006 through 2011;

7) MH growth is expected, but high growth occurs from 1992 through 1996; then MH growth occurs from 1997 through 2011, as expected.

All of these potential futures provide a wide range of uncertainties, and allow various resource strategies to be tested. The next chapter describes the portfolio of resources which can be used to meet the resource needs of the potential futures.

PORTFOLIO

PacifiCorp may choose from a number of alternatives to meet future electricity needs. These alternatives are grouped into three categories: the existing system, demand side resources (e.g., conservation or energy efficiency) and supply side resources (e.g., wind, combustion turbines, etc.).

In evaluating the fit of a particular resource, PacifiCorp considers the eight principles described in the first chapter as well as other characteristics:

Cost and Retail Price Impact: Resources should help the Company minimize costs and keep customer prices as low as possible.

Reliable Service: Resources which improve the Company's ability to provide reliable service to its customers are more valuable.

Efficiency: Resources should provide opportunities to increase either system or customer efficiency.

Environmental Responsibility: The benefits of minimal environmental impact are weighed with other considerations.

Flexibility: Resources are more valuable if they can be acquired in small increments, have short lead times, lead times that can be adjusted, and low capital investment.

Diversity: A resource plan should contain a variety of resources, which includes a variety of fuels.

Dynamic Balance: An economically efficient balance of resources over need reduces risk and allows the Company to effectively respond to uncertainties. It is wise to acquire resources in increments that keep the level of resources close to a dynamic balance.

Innovation: Taking advantage of new opportunities and encouraging new technologies are two ways in which innovation is demonstrated in the portfolio.

Dispatchability: Resources which can be dispatched when needed to meet the Company's capacity needs should balance baseload resources. The more control the Company has over dispatch of a resource, the greater the value that particular resource has for the system. The value of such control for any one resource depends on numerous elements, including but not limited to the resource location, size, operating and maintenance costs and how quickly it can respond to changing load levels.

Fit: Each resource is evaluated on how well it enhances the value of the existing system.

Lost Opportunity: Some alternatives can only be acquired cost effectively within a specific time, after which they become much more expensive or unavailable. For example, it is more cost effective to build energy efficiency into a new home than to retrofit that home to the same efficiency at a later time. In addition, some opportunities for cost effective purchases or acquisitions may be available only within a limited time frame.

This long list of considerations illustrates the difficulty in modeling resource planning. Many of these considerations are not yet successfully modeled, and judgment must be used in developing resource plans.

To be able to compare diverse resources, a life-cycle cost approach is used. The cost of each resource per unit of energy provided is expressed in mills (tenths of a cent) per kilowatt hour on a real levelized cost basis. The cost to the system after new resources have been added is also examined. The actual costs which PacifiCorp would incur in acquiring a certain resource are highly site specific and may be more or less than the estimates used in the resource planning model.

Integrated resource planning compares demand side resources (DSRs) and supply side resources on a consistent basis. However, there are differences in how these two types of resources are acquired. For supply side resources, the utility pays all the costs, such as capital investment, fuel, and operation and maintenance expenses. The sum of these expenses is referred to as the total utility cost. However, for DSRs, the customer may pay some of the costs. For example, it might cost an extra $3000 to build an energy efficient house. Of that amount, the utility may pay a $2000 incentive, leaving the homeowner to pay the rest. The homeowner will be willing to do this because of the future energy savings. The sum of both what the utility pays and what the customer pays equals the total resource cost (TRC) for a DSR alternative. In some cases, there are non-energy benefits such as operational savings, or maintenance costs associated with the conservation measures. The net present value of these costs or benefits are included in the TRC. The TRC is used as one criteria to evaluate the relative merits of one resource plan compared to another.

EXISTING POWER SYSTEM

To quantify future resource requirements, the Company first determines how much electricity it could produce from its existing power system. In this report, the term "existing power system" refers to those PacifiCorp resources that are already on line, as well as known changes for the planning horizon. Tables 3-1, 3-2, and 3-3 show the components of the existing system, and expected changes to it over the 20-year planning horizon for energy, winter peak, and summer peak, respectively. Some known changes increase the power available from the existing system. Examples are current wholesale sale contracts which expire, resources from qualifying facilities (QFs) which will come on line, and system efficiencies which will be in place. Other known changes decrease the power available from the system (e.g., the expiration of current wholesale purchase contracts).

PacifiCorp - RAMPP 2

The Existing System
Table 3-1
Energy (MWa)

This table shows year by year changes in the resources contained in the existing system such as thermal upgrades and system efficiencies.

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Thermal Plants																				
Carbon	165	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167
Centralia	587	587	589	593	595	595	595	595	595	595	595	595	595	595	595	595	595	595	595	595
Cholla	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263
Colstrip	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
Craig	112	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
Dave Johnston	687	687	687	687	687	687	687	689	691	691	691	691	691	691	691	691	691	691	691	691
Hayden	53	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Hunter	919	927	960	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985
Huntington	745	770	782	782	782	782	782	782	782	782	782	782	782	782	782	782	782	782	782	782
Jim Bridger	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273
Naughton	613	613	614	616	616	616	616	616	616	616	616	616	616	616	616	616	616	616	616	616
Wyodak	248	248	248	248	248	254	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Blundell	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Gadsby	66	88	154	154	156	157	157	157	157	157	157	157	157	157	157	157	157	157	157	157
Trojan	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Little Mountain	10	10	10	10	10	10	11	13	13	13	13	13	13	13	13	13	13	13	13	13
Total Thermal	5909	6020	6136	6166	6170	6177	6184	6189	6191	6191	6191	6191	6191	6191	6191	6191	6191	6191	6191	6191
Annual Maintenance	275	333	273	310	270	332	278	347	273	313	272	333	278	347	274	313	272	333	279	347
Net Thermal	5634	5687	5863	5856	5899	5845	5906	5841	5917	5878	5919	5858	5913	5844	5917	5878	5919	5858	5912	5844
Hydro																				
Mid Columbia	199	199	199	199	199	199	199	199	199	199	199	199	199	199	135	135	135	135	56	56
Pacific System	392	393	393	393	392	393	393	393	392	393	393	393	392	393	393	393	392	393	393	393
Utah System	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Total Hydro	637	637	637	637	637	637	637	637	637	637	637	637	637	637	573	573	573	573	494	494
Purchased Power	329	326	345	344	209	183	207	194	186	176	172	159	153	152	153	150	142	142	146	147
Q.F. Contracts	80	97	116	116	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
Efficiencies																				
Transmission	2	4	5	5	6	6	7	8	8	9	9	10	11	11	12	12	13	14	14	15
Distribution	2	6	10	15	19	24	28	33	38	42	47	49	51	53	55	57	59	59	59	59
Hydro	0	0	0	3	6	8	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Total Efficiencies	4	10	15	23	30	38	45	50	56	61	67	69	71	74	76	79	82	82	83	84
Total Resources	6683	6757	6975	6976	6891	6818	6910	6838	6911	6868	6909	6838	6889	6822	6834	6796	6831	6770	6750	6683

PacifiCorp - RAMPP 2

The Existing System
Table 3-2
Winter Peak (MW)

This table shows year by year changes in the resources contained in the existing system such as thermal upgrades, system efficiencies, and BPA peak purchase increase.

Thermal Plants	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Carbon	173	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178
Centralia	622	622	622	627	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631
Cholla	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Colstrip	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144
Craig	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
Dave Johnston	750	750	750	750	750	750	750	750	755	755	755	755	755	755	755	755	755	755	755	755
Hayden	0	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Hunter	1004	1004	1020	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075
Huntington	805	831	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859
Jim Bridger	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387
Naughton	700	700	700	704	704	704	704	704	704	704	704	704	704	704	704	704	704	704	704	704
Wyodak	256	256	256	256	256	256	268	268	268	268	268	268	268	268	268	268	268	268	268	268
Blundell	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Gadsby	97	97	228	228	228	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232
Trojan	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Little Mountain	13	13	13	13	13	13	13	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Thermal	6350	6624	6799	6862	6866	6870	6882	6887	6892	6892	6892	6892	6892	6892	6892	6892	6892	6892	6892	6892
Hydro																				
Mid Columbia	420	420	420	420	420	420	420	420	420	420	420	420	420	420	286	286	286	286	118	118
Pacific System Hydro	854	854	854	854	854	854	854	854	854	854	854	854	854	854	854	854	854	854	854	854
Utah System Hydro	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Total Hydro	1304	1304	1304	1304	1304	1304	1304	1304	1304	1304	1304	1304	1304	1304	1170	1170	1170	1170	1002	1002
Purchased Power	630	609	546	535	359	218	430	420	371	347	340	332	290	290	290	303	253	253	253	269
BPA Peak Purchase	1100	1200	1300	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
Q.F. Contracts	73	73	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118
Efficiencies																				
Transmission	2	4	7	9	11	12	14	16	18	20	21	23	25	27	29	30	32	34	36	38
Distribution	4	17	31	44	58	71	85	99	113	127	141	144	148	151	155	159	163	163	163	163
Hydro	0	0	0	12	78	83	87	87	87	87	87	87	87	87	87	87	87	87	87	87
Total Efficiencies	6	21	38	65	146	166	186	201	217	233	249	254	259	265	270	276	281	283	285	287
Total Resources	9463	9831	10105	10284	10193	10076	10320	10330	10302	10294	10303	10300	10263	10269	10140	10158	10114	10116	9950	9967
Reserve Requirement	1230	1267	1284	1284	1284	1303	1323	1343	1363	1383	1404	1425	1446	1468	1490	1513	1535	1558	1582	1605
Available Resources	8233	8564	8821	9000	8909	8773	8997	8987	8939	8911	8899	8875	8817	8801	8650	8645	8579	8558	8368	8362

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The Existing System
Table 3-3
Summer Peak (MW)

This table shows year by year changes in the resources contained in the existing system such as thermal upgrades, system efficiencies, BPA peak purchase increase.

Thermal Plants	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Carbon	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178
Centralia	622	622	627	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631
Cholla	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Colstrip	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144
Craig	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
Dave Johnston	750	750	750	750	750	750	750	755	755	755	755	755	755	755	755	755	755	755	755	755
Hayden	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Hunter	1004	1020	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075
Huntington	831	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859	859
Jim Bridger	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387	1387
Naughton	700	700	704	704	704	704	704	704	704	704	704	704	704	704	704	704	704	704	704	704
Wyodak	256	256	256	256	256	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268
Blundell	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Gadsby	97	97	228	228	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232
Trojan	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Little Mountain	13	13	13	13	13	13	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Thermal	6624	6668	6862	6866	6870	6882	6887	6892	6892	6892	6892	6892	6892	6892	6892	6892	6892	6892	6892	6892
Hydro																				
Mid Columbia	420	420	420	420	420	420	420	420	420	420	420	420	420	420	286	286	286	286	118	118
Pacific System	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820
Utah System	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Total Hydro	1290	1290	1290	1290	1290	1290	1290	1290	1290	1290	1290	1290	1290	1290	1156	1156	1156	1156	988	988
Purchased Power	690	522	511	500	245	93	33	-11	-17	-41	-50	-92	-97	-97	-84	-34	-34	-34	-18	-18
BPA Peak Purchase	1100	1200	1300	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
Q.F. Contracts	73	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118
Efficiencies																				
Transmission	2	4	7	9	11	12	14	16	18	20	21	23	25	27	29	30	32	34	36	38
Distribution	4	17	31	44	58	71	85	99	113	127	141	144	148	151	155	159	163	163	163	163
Hydro	0	0	0	12	78	83	87	87	87	87	87	87	87	87	87	87	87	87	87	87
Total Efficiencies	6	21	38	65	146	166	186	201	217	233	249	254	259	265	270	276	281	283	285	287
Total Resources	9783	9820	10119	10240	10070	9950	9914	9891	9900	9893	9900	9862	9863	9868	9752	9807	9813	9815	9665	9667
Reserve Requirement	1230	1267	1284	1284	1284	1303	1323	1343	1363	1383	1404	1425	1446	1468	1490	1513	1535	1558	1582	1605
Available Resources	8553	8553	8835	8956	8786	8647	8591	8548	8537	8510	8496	8437	8417	8400	8262	8294	8278	8257	8083	8062

The net energy resources in the existing system are at the same level at the end of the planning period as they are at the beginning, although there are year-to-year changes, and individual components change. The amount of energy available from the thermal plants will increase from 5634 MWa in 1992 to 5844 MWa in 2011. The hydro system will contribute less power, due to decreases in the Company's rights to power from the mid-Columbia resources. Existing purchased power contracts will expire over the period. QF contracts will increase slightly, as known resources come on line. Efficiencies will increase, reducing the need for other new resources.

The resources available to meet the winter peak (Table 3-2) increase over time. The system can provide 8233 MW of available resources (after subtracting the reserve requirement) for the 1992 winter peak, which grows to 8362 MW by 2011. Different components increase or decrease over the 20 years. The thermal system increases from 6350 to 6892 due to system efficiencies. The hydro system decreases due to a reduction in the Company's rights to the mid-Columbia output. Purchased power decreases. The Bonneville Power Administration (BPA) peaking contract ramps up early and then remains at 1400 MW. QF contracts increase slightly, and other system efficiencies of about 280 MW are planned.

The resources available to meet the summer peak (Table 3-3) decrease over time. Most of the components increase: thermal plants, BPA peaking contract, QF contracts, and system efficiencies. However, the decreases in hydro and purchased power are larger. Summer capacity from available resources decreases from 8553 MW in 1992 to 8062 in 2011. Both winter and summer capacity available from the existing system increase from 1992 through 1995, and then decrease.

PacifiCorp recognizes that emerging issues (such as implementation of the 1990 Clean Air Act and growing concern about the viability of fish populations) could have an effect on how much electricity the Company's existing system will be able to produce in the future. The Company did not include in its modeling any major changes in its base thermal or hydro capabilities. Those uncertainties are addressed in the scenarios and other sensitivities.

Characteristics of the System

PacifiCorp's existing system will continue to be the primary source of power supply for meeting customers' future needs. Current energy requirements are met by about 82 percent coal generation, 7 percent company-owned hydro, and 11 percent from power purchases. About 65 percent of the Company's capacity comes from from company-owned thermal generating plants, 10 percent from hydro generation, and 25 percent from power purchases (largely hydro-based). The Company's peaking resources are used by the system in all months of the year, and the energy-return requirements of the peaking contract with BPA means that the cost difference between on-peak and off-peak is relatively small.

RAMPP-2 considers power that will be exchanged and acquired under agreements with Arizona Public Service and Colorado-Ute Electric Association to be part of the existing system. Those agreements are described later in this section.

Additions to the Existing System since RAMPP-1

From 1989 through 1991, PacifiCorp gained additional resources through various efficiency improvements on the thermal, hydro, and transmission and distribution systems. Thermal plant capacity upgrades achieved 76 MW of capacity, availability improvements added 58 MWa, and changing maintenance practices added 200 MWa. On the hydro system, 2.2 MW were added through increasing the efficiency of equipment. On the transmission and distribution system, 1.2 MWa was added through efficiency improvements, including conservation voltage reduction.

In addition, the system added Cholla 4 at 350 MW and Gadsby 3 at 97 MW. Craig and Hayden add 243 MW, Gadsby 1 and 2 will add 131 MW, and APS combustion turbines (CTs) will add 150 MW. All of these are assumed as additions to the existing system during the planning horizon.

Thermal and Hydro Power

The company's mix of thermal and hydro power contrasts with the Pacific Northwest's regional resource system, which is dominated by hydroelectric generation. Almost all of PacifiCorp's coal-fired generation is produced at plants located adjacent to coal mines. These coal plants have low operating costs. Therefore, they are used as baseload plants, i.e., they are run fairly continuously at high output levels. Hydro resources are used to respond to daily, weekly and seasonal fluctuations in load. The Company can conduct maintenance on its thermal plants when hydroelectric power is more available.

By the end of the 20-year planning horizon, a few of the company's hydro and thermal generating units will be 35 or more years old. PacifiCorp plans to extend the life of existing generating plants as long possible, unless new or improved technology demonstrates that extending the life of existing plants is not cost effective. The company's current maintenance activities and improvements are aimed at cost effectively extending the operating life of its plants. Major components will be replaced over time if the replacement is cost effective. Additionally, heat rate improvements will continue to be one of the Company's primary goals.

Power Contracts

Since RAMPP-1, PacifiCorp acquired existing generating facilities from two western utilities. It has completed a generating unit acquisition from Arizona Public Service Company (APS) and a related set of power transactions. It has acquired certain generating assets of the Colorado-Ute Electric Association, and made related agreements with Public Service of Colorado and Tri-State Generation and Transmission Cooperative.

Arizona Public Service

In September 1990, PacifiCorp and APS entered into a series of contracts to help their systems operate more efficiently and take advantage of the diversity in their loads and generating facilities. The contracts included the purchase and operation of a generating plant; the sale and exchange of firm power; cooperative development of transmission facilities and exchange of transmission services. The contracts have received regulatory approval from the Arizona Corporation Commission and FERC. The agreements became effective in July of 1991.

The agreements with APS affect PacifiCorp's power system in several key ways. Under an "Asset Purchase and Power Exchange Agreement," PacifiCorp has purchased the 350 MW Unit 4 of the Cholla generating plant in Arizona, and has secondary rights to 200 MW of power produced by existing APS CTs.

If Cholla 4 is not operating, and APS does not need the output from these CTs, the CT output will be available for PacifiCorp to use. This 200 MW is not included in the existing system, because its availability is too uncertain. In addition, APS will install new CTs with 150 MW of capacity that will be owned by PacifiCorp. APS will have secondary rights to use these new CTs. APS will operate the facilities for PacifiCorp and PacifiCorp will pay the costs of operation.

Under a Long-Term Power Transactions Agreement, which extends through 2020, PacifiCorp will sell firm power to APS during the summer peak season, and APS will make firm supplemental energy available, which PacifiCorp may purchase.

The May to October sale to APS of 175 MW may be increased at APS' option, up to 350 MW between 1996 and 1999. Energy deliveries are based on a 50 to 70 percent load factor for the term of the Agreement. After 1995, APS also will have the option of converting all or part of its purchase to a one-for-one seasonal capacity exchange with PacifiCorp (i.e., the two utilities would trade an equal amount of power during their complementary peaking periods). APS is required to make 125 MWa of supplemental energy available to PacifiCorp each year. PacifiCorp has the right, but not the obligation, to purchase all or part of that energy, and will do so if such purchase benefits PacifiCorp's customers.

Until the existing transmission is upgraded, PacifiCorp can transmit a maximum of 350 MW on APS' transmission system to specified locations.

Colorado-Ute Electric Association

PacifiCorp has purchased 243 MW of generating assets from four power plants formerly owned by the Colorado-Ute Electric Association, a utility which was in bankruptcy proceedings. Under an associated agreement, the Company will sell 176 MW of power under a long-term agreement with Public Service of Colorado, which will supply service to some of Colorado-Ute's former customers. PacifiCorp also has a 50 MW seasonal exchange agreement with Tri-State Generation and Transmission. This exchange allows Tri-State to take deliveries at a 70 percent monthly load factor from PacifiCorp in the summer period (April-September), and return the energy in the winter period (October-March). These arrangements were approved by the bankruptcy court on February 7, 1992. On April 15 FERC accepted the contracts for filing, and operations under these agreements commenced on that date.

System Efficiencies

RAMPP-1 identified several system efficiency improvements which could increase PacifiCorp's base system of resources. Resource efficiency improvements are included in RAMPP-2 as part of the existing system in each year of the planning horizon, because the

Company plans to pursue them regardless of the rate of increase in electricity sales. Included are improvements to the company's thermal plants, hydro plants, transmission system, distribution system and conservation voltage regulation. Conservation voltage regulation (CVR) means electricity load is reduced by reducing the voltage supplied to the customer. Lower voltages, while still within the range of common operating standards (114-126 V), can directly reduce the amount of electricity used or increase the efficiency of some appliances. CVR can produce these benefits without dropping below 114 volts on short feeders. PacifiCorp has conducted a pilot study in the area of Corvallis, Oregon, and has pursued CVR in areas of California where it is cost effective. There are, however, some risks: CVR can reduce the quality of electricity for computer and process control equipment and can create operating problems for PacifiCorp's distribution system.

Thermal plant improvements increase the capacity, energy and/or efficiency of the plant. Additional capacity of 147 MW will be added to the existing thermal system during the planning horizon. Hydro plant improvements are expected to add 10 MWa and 87 peak MW. Transmission and distribution efficiency improvements are expected to add 74 MWa.

Influences on the System

PacifiCorp considers a number of additional factors in evaluating the potential for each resource alternative. These factors that influence the system are described below.

Pacific Northwest Coordination Agreement

PacifiCorp is one of 15 power generating utilities that share in the Pacific Northwest Coordination Agreement with the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers and the Bonneville Power Administration. That agreement provides for coordinated operation of the hydroelectric dams on the Columbia River and other Northwest river systems, so they collectively produce maximum power at maximum efficiency. Participants must meet requirements for flood control, irrigation, recreation, fish flows and navigation before power can be generated. The Agreement limits the ways in which PacifiCorp can use the hydro resources to meet its load requirements. The 1964 Agreement will expire in 2003. PacifiCorp has entered into negotiations which would facilitate continuation of that contract.

Transmission

PacifiCorp's bulk power system can be represented by several distinct load/resource areas. The transmission system linking Wyoming, Utah and the Pacific Northwest has in the past provided PacifiCorp with opportunities to acquire new resources which can easily be integrated into the existing system. The interconnections within the system have also allowed the Company to take advantage of the load and resource diversities between the Pacific Northwest and Rocky Mountain and Desert Southwest areas. By taking advantage of these interconnections and diversities, the Company has increased system operating efficiencies beyond those already achieved by the Utah Power/Pacific Power merger.

However, the transmission system has capacity constraints which limit the flow of power between certain load and resource areas. Planning for resource additions must recognize these limitations and, where appropriate, point to logical transmission improvements. At present, resources exist on the east side of the system that could be more completely utilized in the west if more transmission capacity were available. Transmission plans are being developed to increase the capacity to move additional resources from east to west. The transmission that will be required will be very site dependent. The Company is now investigating its short- and long-term transmission capability and requirements and developing a long-term transmission plan. The plan will enable the Company to better evaluate the appropriate geographic locations for specific resources.

Peak and Energy Reserves

All utilities must maintain a margin of resources above loads to assure system reliability in spite of generating unit outages and other future uncertainties. PacifiCorp sets its reserves for forced outages based on studies by the Northwest Power Pool and the InterCompany Pool (ICP) in accordance with inter-utility reserve sharing agreements. The Company's 1991-92 planning reserve level is 1162 MW. This amount is calculated by summing the critical peaking period ICP reserve allocation for Pacific Power and Utah Power.

The addition of Cholla, Craig and Hayden has increased PacifiCorp's capacity reserve requirement above the 1162 MW level. The reserve requirement increases with each new resource acquisition because each addition carries with it a risk of reduced availability. The modeling for RAMPP-2 assumes that the required reserve margin for the system increases by 15 percent of the additional capacity provided by each additional resource.

An energy margin is also needed to maintain a dynamic balance of resources. The Company needs to maintain an economically efficient margin of resources over loads to be able to manage operating constraints and future uncertainties. The best balance between surplus and deficit is determined by economic and strategic criteria. On a planning basis, the Company tries to maintain an energy margin sufficient to meet two or three years of growth, while keeping costs reasonable.

Hydro Relicensing

Several of PacifiCorp's hydro generating units will come up for relicensing during the next 20 years. The Company will actively pursue relicensing of these resources, and assumes in this plan that those efforts will be successful. Any loss of those low-cost resources would create a hardship for both the Company and its customers. The hydro units and their dates of relicensing are as follows: North Umpqua (185 MW) in 1997, Yale (130 MW) in 2002, Rogue (40 MW) in 2006, Swift (205 MW) in 2007, and Klamath (160 MW) in 2007, for a total of 720 MW.

Canadian Entitlement

In 1964 the United States and Canada signed a treaty under which the United States paid part of the cost of building hydroelectric dams in Canada. In return Canada and the United States would share equally the downstream benefits of those dams, measured in kWh. The benefits included flood control, irrigation, and hydro regulation. Canada did not immediately need its half of the downstream benefits, so it sold them to the United States on a declining schedule under the Canadian Entitlement and Columbia Storage Power Exchange (CSPE). As of 1998, the half of the power that the U.S. purchases must be replaced or returned to Canada. Early negotiations are underway to extend the purchase of benefits by U.S. parties. Those negotiations involve Canada, BPA, non-federal owners of the mid-Columbia hydro projects, and purchasers of those projects such as PacifiCorp. The future benefits and costs to the Company are highly uncertain. PacifiCorp's capacity available via CSPE decreases from approximately 96 MW in 1990 to 0 by 2003, and, the Company's return obligation is reduced from approximately 29 MW (off-peak) in 1990 to 0 by 2003.

Flexibility from Wholesale Purchases and Sales

The wholesale market provides added flexibility for the economic implementation of the company's long-term resource plan. Such flexibility occurs in both the short-term and long-term firm markets.

On any day, the Company may have more resources available than it needs to meet actual system loads. Power schedulers seek wholesale markets for this short-term surplus generating capability to the degree that those sales can help the Company pay its fixed costs. Similarly, if short-term reductions in generating capability and/or extreme load requirements occur, power schedulers will look to the wholesale market to acquire power to economically meet short-term system needs.

Long-term power planners look to the wholesale market to meet the long term needs of the system. Wholesale opportunities can take various forms -- long-term wholesale purchases, sales, exchanges, or a combination of the three.

The Company currently has a number of existing long-term wholesale purchase power contracts. Some of the larger contracts include: Colockum Transmission Company (102 MW); Tri-State Generation and Transmission Association (150 MW); Hanford WNP-1 Project (80 MW); and Washington Water Power (150 MW). PacifiCorp has an option with Tri-State to extend current deliveries of 600,000 MWh annually, for three years (1996-98). RAMPP-2 does not use this extension as a resource due to unknown price and delivery terms which must be renegotiated at the time of extension. However, PacifiCorp has a good working relationship with several utilities. As a result, although existing contracts may not contain extension provisions, the company anticipates the potential to quickly negotiate or extend deliveries on existing contracts. If such an extension or negotiation could result in cost effective resources, it could enable PacifiCorp to meet unanticipated load growth or provide power if other resource options are delayed.

Marketing power on the wholesale market helps the Company meet its strategic growth and revenue requirements by generating revenue and facilitating acquisitions. Revenue from wholesale sales is passed on as a credit for retail customers, thereby stabilizing retail rates and making PacifiCorp's electricity more competitive on the retail side. Long-term contracts for the sale of power provide stable revenues when an economic downturn affects retail and short-term secondary sales. Long-term contracts are executed on a take-or-pay basis with reputable utilities and are not susceptible to swings in the local economies.

PacifiCorp's wholesale market can be divided into four separate regions: Pacific Northwest, Pacific Southwest, Rocky Mountain, and the Desert Southwest. Over the next two to four years, all areas will require additional resources with the exception of the Rocky Mountain Region. As a result of new east side transmission access through Palo Verde, and additional transmission access through the agreement with APS, PacifiCorp has more flexibility to reach the southern California markets. However, competition for existing wholesale markets is expected to remain intense in all regions.

DEMAND SIDE PORTFOLIO: ENERGY EFFICIENCY PROGRAMS

PacifiCorp has long been a leader in the development of energy efficiency programs in its DSR acquisition activity. The Company has particularly focused on identifying and overcoming the existing hurdles for customers to accept and pursue energy efficiency. In 1979, the Company introduced a "zero interest weatherization program" -- the first of its kind in the country -- to help customers pay for residential weatherization. In the 1980s, the Company joined the Bonneville Power Administration in sponsoring a major energy efficiency undertaking: the Hood River Conservation Project. This project involved installing conservation measures throughout an entire community and tracking and evaluating the results. More recently, PacifiCorp has been a strong advocate of new residential building codes to achieve greater efficiencies. It has had one of the highest participation rates of any utility in the Northwest in the Super Good Cents program sponsored by BPA. That program provides incentives for builders and developers to construct highly efficient new homes.

The level of DSR available varies with the load forecast, because estimates of potential savings depend on the economic forecast used, as well as on detailed end-use information. The amount of electricity that can be saved through energy efficiency measures is directly tied to the number of homes, businesses and industries served. The level of other DSR acquisitions (which is captured by the load forecast), also varies with the load forecast.

End Use

PacifiCorp prepared detailed end-use models for all customer classes by geographic area. These indicate how much electricity various groups of customers use for different purposes. The models for residential and commercial end use relied heavily on methods used by the Northwest Power Planning Council. Computer models of prototype buildings were adjusted to match current PacifiCorp customer consumption patterns, and then used to estimate potential costs and savings from specific conservation measures. A similar process produced the estimated savings for specific industries. More detail on the end use models is available in the Demand Side Technical Appendix.

Many considerations went into developing the programs that offer efficiency improvements to customers: the type of measures to be included, marketing and development costs, customer interests and choices, administrative and workload requirements, rate equity between participants and non-participants, scheduling acquisition for the time when additional resource needs are anticipated, and the ability to "ramp up" programs when needed. The programs used in this planning cycle are discussed in more detail in the Demand Side Technical Appendix.

Cost Ceilings

In developing the programs, it is necessary to have some idea of a cost ceiling -- that is, how far up on the cost curve one should go when considering which measures to include in programs. The ceiling on cost effectiveness is a value that will emerge from the avoided costs that will be based on RAMPP-2. Yet for program planning purposes, it was necessary to have a working assumption. A cost ceiling of 55 mills/kWh was used. Efficiency programs were also given a 10 percent cost advantage compared to conventional resources.

This is a difficult issue; alternative cost effectiveness levels will continue to be discussed within the Company and with the public advisory group. The Company will address the appropriate cost effectiveness level for DSR acquisitions with each jurisdiction, and on a case-by-case basis for each acquisition program.

The Energy Service Charge

Market research shows customers often have difficulty when required to finance their part of the costs for demand side efficiencies. To help customers overcome that financial hurdle, and still keep utility costs low, PacifiCorp has introduced an innovative financing mechanism called the Energy Service charge (ESc). The Company provides full up-front financing for the efficiency improvements, which the customer then repays out of his or her energy savings through an Energy Service charge on the customer's monthly bill. The charge minimizes the effect that efficiency programs might otherwise have on retail prices.

The ESc is designed so the customer who directly benefits from the efficiency measure pays most of the cost rather than the cost being spread to all customers. In addition to fair pricing, the ESc offers a number of advantages. It provides front-end financing of an entire comprehensive package of energy efficiency measures, including lighting, windows, HVAC, etc., as opposed to a rebate approach that is often tied to specific measures. Thus the ESc approach has the potential to capture greater savings. The ESc is also simple and self-policing. Customers who pay for efficiency are more likely to insist the measures work and are cost effective, which adds to the Company's ability to verify savings.

PacifiCorp plans to use the ESc in many of its new programs. While reducing the impact on retail prices is important, the company's first objective is to acquire the most cost effective resources. To achieve high penetration, programs must offer customers services that achieve the anticipated energy savings. The Company is not relying solely on the ESc approach for the entire demand side effort. Traditional rebate programs, like the Super Good Cents program, are being combined with ESc programs to acquire DSRs.

Program Details

Table 3-4 summarizes the DSR programs used in the resource planning process. This table shows program costs and resource yields at the MH level. The electricity saved through the programs is described as net savings, beyond the level of other DSR acquisitions already assumed in the forecast. At the MH level, these programs provide 781 MWa of energy, 1309 MW of winter peaking, and 1072 MW of summer peaking. The cost of each program is based on total resource cost. To compare DSRs with other alternatives, the costs of the programs have been expressed as real levelized values. The levelization process uses the company's effective cost of capital at 4.22 percent real.

PacifiCorp - RAMPP 2
Major DSR Acquisition Programs
Medium-High Forecast
Acquisition Programs Based on Need for Resource in 1996
Table 3-4

Program	Physical Goal	Resource Yield MWa	Utah %	Total Levelized Resource Cost Mills/kwh	Levelized Utility Cost Mills/kwh	Gross Utility Program Cost MM '91 $	Key Features
Lights & Water Heater Appliance Retrofit	300,000 Homes	28	36	23	17	62	Lights, appliances in homes without electric space heat
Residential Retrofit	155,000 Homes	56	36	27	8	235	cost share via energy service charge, weatherization
Industrial	300 Plants	375	52	26	0	1099	technical assistance, utility finance
New Commercial	76,000 Buildings	140	46	28	5	1000	on-going lost opportunities program, utility finance
New Residential	176,000 Homes	53	11	31	26	348	long term program in addition to MCS includes manufactured homes
Commercial Retrofit	43,000 Buildings	129	31	40	-1	615	cost share via energy service charge, utility finance
ALL PROGRAMS		781	43	26	4	3359	

PacifiCorp - RAMPP 2
Demand Side Resources
By Economic Growth Forecast
Table 3-5

Energy Savings by Program	Low Forecast MWa	Low Forecast TRC mills/kWh	Med-Low Forecast MWa	Med-Low Forecast TRC mills/kWh	Med-High Forecast MWa	Med-High Forecast TRC mills/kWh	High Forecast MWa	High Forecast TRC mills/kWh
Appliance Retrofit	2	23	15	23	28	23	28	23
Residential Weatherization	56	28	56	29	56	27	56	27
Industrial	174	28	258	27	375	26	471	26
New Commercial	59	31	96	30	140	28	155	29
New Residential	19	32	35	31	53	31	69	31
Commercial Retrofit	125	29	129	31	129	31	129	32
TOTAL Available by 2011	435	21	588	29	781	26	910	28

Demand Savings by Program (MW)	Low Forecast Winter	Low Forecast Summer	Med-Low Forecast Winter	Med-Low Forecast Summer	Med-High Forecast Winter	Med-High Forecast Summer	High Forecast Winter	High Forecast Summer
Appliance Retrofit	3	3	24	24	46	46	47	47
Residential Weatherization	102	23	103	23	91	20	91	20
Industrial	290	290	430	430	625	625	785	785
New Commercial	91	71	148	115	216	169	239	187
New Residential	28	10	52	19	78	29	239	37
Commercial Retrofit	207	148	214	154	215	154	215	154
Water Heater Load Control	191	115	213	128	213	128	225	135
TOTAL Available by 2011	914	660	1183	892	1484	1170	1705	1365

Table 3-5 shows an estimate of the costs and optimal schedule for acquiring DSRs for each of the four load forecasts. Each program provides both energy and peak savings. Capacity needs were calculated and considered in developing all of the programs. The only load management program included is a draft program for load control on residential water heaters. Its costs were not competitive with other peaking resources. Additional details on all of the programs are included in the Demand Side Technical Appendix.

Some of the costs appear to decrease as higher amounts of DSR resources are achieved. This is because some lost opportunity programs are operated first, even though they aren't least cost. This drives up the early costs. Also, the cost of implementing DSR programs depends partly on its administrative and marketing costs. For example, in the early years, when the programs are in their developmental stages, the administrative costs will be higher per kWh of resource acquired than in later years. Marketing costs will also vary by program, depending on how easy it is to communicate program benefits to the potential participants.

The DSR programs can be used to different degrees as needed. The rates at which annual program levels will be increased for the MH and high forecasts are at the maximum considered to be attainable. Under MH or high growth, DSR programs would be increased to full levels of operation around 1996. For the low and ML forecasts, programs are postponed, based on reduced need for the resource. Under low growth, programs would be held at maintenance levels until around 2005. Under ML growth the largest programs, in the commercial and industrial sectors, would be pursued first. Lost opportunity programs will be accelerated under all of the forecasts because the resources they acquire are available only for a limited time.

Changes since RAMPP-1

There have been several changes in demand side planning since RAMPP-1. RAMPP-2 assumes much higher economic growth than RAMPP-1. Estimates of the potential efficiency that could be captured from the commercial sector have also been recalculated. As a result of these changes, the amount of resource expected to come from efficiency programs is much higher. Compared to RAMPP-1, current estimates suggest about twice the energy savings is available at about three times the total investment cost.

SUPPLY SIDE PORTFOLIO

This section describes each of the technologies in the supply side portfolio. Tables 3-6 and 3-7 show, for each technology, the non-cost and cost characteristics, respectively. Table 3-8 shows the emissions by plant type for each technology. Following is a discussion of each technology included in the portfolio of new generation resources.

PacifiCorp - RAMPP 2
Supply Portfolio
Plant Non-Cost Information
Table 3-6

	Lead Time	Capacity (MW)	Potential No. of Units Avail.	Fuel Type	Type of Resources	Dispatchable	Operability	Risks
Gas Fired Plants /1								
Large CC CT	4 - 5 Years	250	20	Gas/Oil	Cycling/Baseload	Yes	Good	Fuel Price, Fuel Delivery
Medium CC CT	4 - 5 Years	125	8	Gas/Oil	Cycling/Baseload	Yes	Good	Fuel Price, Fuel Delivery
Large SC CT	4 - 5 Years	150	9	Gas/Oil	Peaking/Cycling	Yes	Good	Fuel Price, Fuel Delivery
Medium SC CT	4 - 5 Years	100	4	Gas/Oil	Peaking/Cycling	Yes	Good	Fuel Price, Fuel Delivery
Small SC CT	4 - 5 Years	40	4	Gas/Oil	Peaking/Cycling	Yes	Good	Fuel Price, Fuel Delivery
Coal Fired Plants								
Hunter Unit 4	5 - 7 Years	400	1	Coal	Baseload	Yes	Good	Emissions
Wyodak Unit 2	5 - 7 Years	256	1	Coal	Baseload	Yes	Good	Emissions
AFB Coal	7 - 10 Years	250	4	Coal, Etc.	Baseload	Yes	Good	Emissions
IGCC	7 - 10 Years	500	4	Coal, Etc.	Baseload	Yes	Good	Emissions
Cogen Resources /2								
Cogen 1	1 - 4 years	100	0 - 4	Gas, Etc.	Baseload	No	Moderate	Inflexible Power Delivery
Cogen 2	2 - 4 years	100	3 - 10	Gas, Etc.	Baseload	No	Moderate	Inflexible Power Delivery
Cogen 3	2 - 4 years	100	6 - 14	Gas, Etc.	Baseload	No	Moderate	Inflexible Power Delivery
Renewables								
Geo. Steam Purchase	5 - 7 Years	50	3	Geothermal Steam	Baseload	Yes	Good	Capital Costs, Site Acceptibility
Geothermal	5 - 7 Years	100	4	Geothermal Steam	Baseload	Yes	Good	Capital Costs, Site Acceptibility
Wind /3	2 - 4 Years	16 - 40	--	Wind	Baseload	No	Unclear	Output Uncertainty
Luz Solar Plant /4	2 - 4 Years	50	2	Solar/Gas	Peaking/Cycling	Yes	Good	Capital Cost (may not be competitive)
Solar Goal	2 - 4 Years	100	4	Solar/Gas	Peaking/Cycling	Yes	Good-Mod.	Capital Cost (may not be competitive)
Hydro /5								
Pumped Storage	4 - 5 Years	100	13	Electricity	Peaking/Cycling	Yes	Good	Capital Costs, Site Acceptibility

Notes: /1 SC CT's and CC CT's could use oil as a backup fuel.
/2 Cogeneration plants have some fuel flexibility, unless the cost of conversion is high.
The fuels include, gas, biomass, black liquor, coal and oil.
Number of units varies with economic forecast.
/3 Up to 500 MW have been identified.
/4 Luz Solar Plants may use gas to supplement solar energy production.
/5 Pump Storage plants are "fueled" by off peak electricity.

PacifiCorp - RAMPP 2
Supply Portfolio
Plant Cost Information
Table 3-7

	Capital Costs Installed$/kW	Real Levelized Fixed Charge	Annual Cost ($/kW Yr)	Fixed O&M ($/kW yr)	Total Fixed Cost ($/kW yr)	Variable O&M $/MWh	Heat Rate (btu/kWh)	Real Levelized Fuel Costs in 1991 $/MWh by Plant Inservice Date			Annual Capacity Factor Ranges			2001 Plant Real Levelized Costs by CF (in 1991 $/MWh)		
								1991	2001	2010	Low	Exp.	High	Low	Exp.	High
Gas Fired Plants																
Large CC CT	$760	10.80%	$83.88	$9.34	$93.22	$1.54	7600	$21.51	$27.44	$29.49	20%	70%	90%	$82.17	$44.17	$40.79
Medium CC CT	$895	10.80%	$96.62	$9.34	$105.96	$1.54	8300	$23.49	$29.96	$32.20	20%	50%	90%	$91.97	$55.69	$44.93
Large SC CT	$482	11.07%	$53.34	$2.33	$55.67	$2.68	11000	$31.13	$39.71	$42.68	10%	20%	90%	$105.93	$74.16	$49.44
Medium SC CT	$482	11.07%	$53.34	$2.33	$55.67	$2.68	11500	$32.55	$41.52	$44.62	10%	20%	90%	$107.74	$75.96	$51.25
Small SC CT	$600	11.07%	$66.40	$2.33	$68.73	$2.68	10500	$29.72	$37.91	$40.74	10%	20%	90%	$119.04	$79.81	$49.29
Coal Fired Plants																
Hunter Unit 4	$1,581	10.80%	$170.70	$0.00	$170.70	$3.44	10000	$10.60	$11.60	$13.30	40%	80%	90%	$60.36	$36.00	$33.29
Wyodak Unit 2	$1,847	10.80%	$199.39	$0.00	$199.39	$4.16	11000	$11.66	$12.76	$14.63	40%	80%	90%	$66.33	$37.87	$34.71
AFB Coal	$1,970	10.80%	$212.66	$32.40	$245.06	$4.50	10045	$10.65	$11.65	$13.36	40%	80%	90%	$86.09	$51.12	$47.24
IGCC	$2,090	10.80%	$225.62	$34.00	$259.62	$3.47	9500	$10.07	$11.02	$12.64	40%	80%	90%	$88.58	$51.54	$47.42
Cogen Resources																
Cogen 1	$700	10.80%	$75.57	$32.85	$108.42	$2.50	5000	$16.70	$21.30	$22.90	60%	80%	90%	$44.43	$39.27	$37.56
Cogen 2	$1,120	10.80%	$120.90	$32.85	$153.75	$10.00	6500	$21.71	$27.69	$29.77	60%	80%	90%	$66.95	$59.64	$57.20
Cogen 3	$1,680	10.80%	$181.36	$32.85	$214.21	$10.00	6500	$30.36	$38.81	$41.73	60%	80%	90%	$89.53	$79.34	$75.94
Renewables																
Geo. Steam Purchase	$1,600	10.80%	$172.72	$56.00	$228.72	$20.00	10000	$0.00	$0.00	$0.00	70%	80%	90%	$57.30	$52.64	$49.01
Geothermal	$2,680	10.80%	$289.31	$93.80	$383.11	$3.00	10000	$0.00	$0.00	$0.00	70%	80%	90%	$65.48	$57.67	$51.59
Wind	$750	11.86%	$88.94	$4.45	$93.38	$13.24	N.A.	$0.00	$0.00	$0.00	22%	25%	30%	$61.69	$55.88	$48.77
Luz Solar Plant	$2,822	10.30%	$290.72	$35.97	$326.69	$3.55	10000	$28.30	$36.10	$38.80	20%	40%	60%	$190.02	$105.81	$83.75
Hydro																
Pumped Storage	$760	10.80%	$82.04	$0.00	$82.04	$1.87	N.A.	$16.00	$16.00	$16.00	10%	30%	40%	$116.86	$54.42	$46.62

PacifiCorp - RAMPP 2
Emissions by Plant Type
Table 3-8

	Heat Rate (btu/kWh)	Fuel Type	SO2 lbs/MWh	NOx lbs/MWh	TSP lbs/MWh	CO2 lbs/MWh
Gas Fired Plants						
Large CC CT	7600	Gas / Oil	0.009 - 0.012	0.396 - 0.528	0.009 - 0.012	800 - 1067
Medium CC CT	8300	Gas / Oil	0.009 - 0.012	0.432 - 0.576	0.009 - 0.012	874 - 1165
Large SC CT	11000	Gas / Oil	0.009 - 0.012	0.576 - 0.768	0.009 - 0.012	1158 - 1544
Medium SC CT	11500	Gas / Oil	0.018 - 0.024	0.603 - 0.804	0.018 - 0.024	1211 - 1614
Small SC CT	10500	Gas / Oil	0.009 - 0.012	0.549 - 0.732	0.009 - 0.012	1105 - 1474
Coal Fired Plants						
Hunter Unit 4	10000	Coal	1.620 - 2.160	4.050 - 5.400	0.270 - 0.360	1935 - 2580
Wyodak Unit 2	11000	Coal	1.188 - 1.584	4.455 - 5.940	0.297 - 0.396	2129 - 2838
AFB Coal	10045	Coal	1.080 - 1.440	1.206 - 1.608	0.135 - 0.180	1935 - 2580
IGCC	9500	Coal	0.279 - 0.372	0.486 - 0.648	0.009 - 0.012	1780 - 2374
Cogen Resources						
Cogen 1	5000	Gas, Oil, etc	0.009 - 0.012	0.792 - 1.056	0.009 - 0.012	527 - 702
Cogen 2	6500	Gas, Oil, etc	0.009 - 0.012	1.026 - 1.368	0.009 - 0.012	685 - 913
Cogen 3	6500	Gas, Oil, etc	0.009 - 0.012	1.026 - 1.368	0.009 - 0.012	685 - 913
Renewables						
Geo. Steam Purchase	N.A.	Geo.Steam	0	0	0	0
Geothermal	N.A.	Geo.Steam	0	0	0	0
Wind	N.A.	Wind	0	0	0	0
Luz Solar Plant *1/	10000	Gas backup	0	0.396 - 0.528	0	264 - 352
Solar Goal	10000	Solar	0	0	0	0
Hydro						
Pumped Storage	N.A.	Electricity	Depends on off peak electric generation resource.			

Notes 1/: Luz Solar Plant emission levels based on 40% CF using gas cofiring.

The BPA Entitlement Agreement

If the Company exercises its option to execute the Agreement, it has the right to purchase about 65 MWa of energy and up to 164 MW of capacity during the months of November through April. The term of the Agreement cannot extend beyond 30 years. Because of the substantial uncertainties associated with the Agreement's pricing provisions, the Company views this resource as available, but will not rely on it. The value of this resource will depend on pricing and other operating considerations. The Company would likely wait until the last possible date to execute the contract. Under that assumption, November, 1997, is the earliest that power deliveries would begin. Prices paid by PacifiCorp would be based on the performance of surrogate nuclear units unless and until WNP-3 operates, then prices would be based on actual WNP-3 operating costs. Based on plant performance at the surrogate nuclear units, prices would start at about 27.5 mills/kWh.

If the Agreement is executed by PacifiCorp, BPA will have the right to purchase energy from PacifiCorp during the months of September through June. The amounts purchased would be based on the historic availability of surrogate nuclear units but not exceeding 83 MWa. PacifiCorp deliveries would be delayed or limited under certain dry hydro conditions. Prices paid by BPA would be based on the Company's operation and maintenance (O&M) costs of its CTs, if utilized, or the fully distributed cost of other resources used to supply the energy but not to exceed the O&M costs of the CTs.

Simple Cycle Combustion Turbines (SCCTs)

In a simple cycle combustion turbine, fuel (natural gas) is burned in the presence of compressed air. The resulting gas mixture, at an elevated temperature, is allowed to expand through a power turbine. The power turbine turns both the compressor (used to generate the compressed air) and an electric generator. The advantages of combustion turbines include low capital cost and load shaping capability (i.e., they can be employed quickly and relatively easily to respond to fluctuations in electricity load).

SCCT technology is considered mature and commercially available. Construction lead times are about two years with another two years needed for the necessary permits. Environmental impact is low, with the greatest problem being nitrogen oxide (NOx) emissions. Methods of controlling NOx emissions include steam injection, dry low NOx burners or selective catalytic reduction.

The main disadvantages of an SCCT is its high heat rate (more fuel must be burned to produce one kilowatt hour of electricity than is required in a coal plant, for example) and cost of fuel. Because of higher fuel costs, these generators are usually only used to provide peaking power. They typically do not have capacity factors (the ratio of time they actually operate to the amount of time they could operate) higher than 15 to 20 percent.

SCCTs are often used for load following -- i.e., they can be turned on or their output can be increased as loads increase during a typical day, similar to the way hydro facilities are used. However, hydro provides greater flexibility, including the ability to more quickly ramp up or down to meet immediate changes in load levels. Hydro provides both seasonal and daily flexibility. A SCCT cannot replace hydro, but it is the resource alternative whose benefits most closely match those of hydro.

Combustion turbines offer the advantage of being easy to expand, if enough land is available for the additional capital equipment. Additional efficiency can be obtained by adding a heat recovery steam generator to a combustion turbine and creating a combined-cycle system. A gasifier could be added to create an integrated gasification combined cycle (IGCC) system to use coal, if natural gas becomes too expensive.

All of the resources in the portfolio could be brought on line at any time during a calendar year. However, for ease of modeling, it is assumed in developing the illustrative plans that all resources would come on line in January. This created a problem in the model's ability to meet the system's peaking needs. Peaking needs are modeled for both winter and summer, but when peaking resources could only come on line in the winter, summer peaking needs were more difficult to meet. Therefore, SCCTs are specified in the model to be able to come on line in either January or July. Allowing SCCTs to come one line in either January or July greatly alleviated the summer peaking constraint, and is consistent with actual utility operations.

Combined-Cycle Combustion Turbines (CCCTs)

Like SCCTs, combined-cycle combustion turbines use natural gas which is fired in a combustion turbine generator. However, with CCCTs, the hot exhaust gases from the gas turbine are passed through a heat recovery steam generator that produces steam, which is then used to generate additional power in a conventional steam turbine.

CCCT technology is considered mature and commercially available. Construction lead times are similar to those of the simple-cycle machines. Siting and permitting needs are also similar for the two technologies, except the CCCTs require makeup water and disposal of cooling tower blowdown (particulate matter that accumulates in the tower).

Capital costs for a combined cycle system requires capacity factors of more than 35 percent for the cost of electricity from CCCTs to be competitive with other alternatives. The use of the combined cycle greatly improves the heat rate of the system and makes it cost effective to use natural gas for moderate or base load generation. The main problem is the uncertainty of natural gas prices.

Wind

Wind turbines have had two generations of development within the last 13 years and are now entering their third generation of development and testing. Intermediate sized systems that convert wind to energy (i.e., 50 to 500 kW wind turbines) have evolved into a proven generation technology. Advantages of wind power generation include size flexibility, minimum environmental impact, no fuel cost and a short lead time for construction.

Important considerations in selecting a wind resource site are elevation, topography and terrain. Wind farms will typically be located within wind corridors, such as canyons or valleys, high plains or plateaus, or on high elevation ridge crests. A wind park that produces 50 MW is considered the minimal practical size. The most wind power that can be effectively installed along a ridge is 14 MW per linear mile -- meaning even a park as small as 50 MW would require more than three linear miles of land.

The most important factor to the success of a wind farm is a consistently strong wind. The average wind speed for a site to be considered acceptable must be greater than 14 mph. Since wind power density is directly proportional to wind velocity cubed, a small increase in wind speed will significantly increase energy output. The wind turbines are connected to a step-up transformer for transmission to a load source or transmission line.

While relatively successful wind farms have operated in California, experiences with wind turbines installed at higher altitudes in colder climates have not been as positive. There is only limited operating experience in high altitude, cold weather locations.

Disadvantages include a low capacity factor, the variability of most wind sources, and the displeasing aesthetic effect of large numbers of wind machines on the landscape. The economics are highly site-specific, and reliable cost estimates require detailed site studies. Because of limited control of a wind farm, wind that peaks at approximately the same time as the system load peaks is desirable. If the daily and annual peak of the wind resource corresponds adequately with the peak of the utility, the power produced by the wind farm will have a greater value.

The Company is committed to pursuing wind as a resource option and determining the cost effectiveness of the newest wind technology. Negotiations with U.S. Windpower and other developers are currently underway to site and develop a wind power project in southeastern Washington and/or in Wyoming.

Geothermal

Heat from the earth has been used to generate electricity for many years at various locations around the world. Geothermal fluids of a sufficient temperature are raised to the surface and partially depressurized. Flashed steam plants use the steam that is produced to drive a turbine generator. For geothermal fluids that are too cool to produce useful amounts of steam, binary cycle plants are used. They use the geothermal fluid to vaporize a secondary working fluid that has a low boiling point. The secondary working fluid is then used to drive the turbine generator. Both flashed steam and binary cycle units are demonstrated technologies and are commercially available.

Geothermal facilities can be developed comparatively quickly -- approximately 24 to 36 months for construction. However, confirming the quantity and quality of a geothermal resource is a difficult, expensive and risky business. The cost of the geothermal working fluid (the hot liquid that comes from below the surface) is often the primary issue. Unless the Company owns the resource, the cost of buying the working fluid from a different owner or developer is often higher than the cost of coal or natural gas. In addition, the long-term reliability of the working fluid can be uncertain. The steam resource at Pacific Gas & Electric's Geyser Plants is already diminishing. Geothermal energy is attractive from an environmental point of view, but the number of suitable sites is limited.

Geothermal technology is considered a mature technology but, as with wind, is highly site-specific in application. PacifiCorp is committed to pursuing the geothermal resource option. The most likely site for future development would be the Roosevelt steam field in Utah, where the Company's Blundell plant is located. The current contract for steam for the Blundell plant was signed in January of 1991, and extends for 30 years. Other companies could drill new wells for steam and develop additional plants there. In addition, PacifiCorp has received proposals from geothermal developers for 90 MW of potential resource in the current RFP bidding process.

Solar

Energy from the sun can be converted to electricity through photovoltaic systems and thermal energy conversion. All systems require large direct radiation values to operate efficiently. In photovoltaic systems, electricity is made directly from the sun. Photovoltaic systems (PV) as a bulk power resource will not be economically competitive with other alternatives for the foreseeable future. They still cost about three times as much as conventional coal-fired generation. PV systems are an economical choice for providing low levels of power to remote locations, where transmission costs can be extremely high.

In a solar thermal system, electricity is generated by heating a fluid to drive a heat engine. Solar thermal systems have been built, demonstrated and commercialized. There are three basic solar thermal power plant technologies: 1) dish systems, 2) parabolic trough, and 3) central receiver. The technology for dish systems is not yet commercially viable. Parabolic trough systems were commercially available through LUZ International Ltd (LUZ) until the end of 1991 when the LUZ organization collapsed financially. There is now no major turnkey supplier of this technology. LUZ built plants ranging in size up to 80 MW to comply with Public Utilities Regulatory Policy Act (PURPA) requirements. LUZ proposed to design and build plants for utility ownership up to 200 MW in size.

Central receiver/molten salt plants could be the technology that will provide high value energy at the lowest cost of any bulk power renewable resource in the 2000-2010 time frame. Development efforts such as Solar II suggest that 100-200 MW central receiver/molten salt plants may be commercially available at the beginning of the next century. The system can provide dispatchable energy from thermal energy stored in molten salt. Energy storage allows the plant to have an annual capacity factor of 40 to 60 percent, compared to 25 percent for other solar technologies.

Solar II is a test facility for the central receiver/molten salt technology. The $39 million project will be jointly funded by the U.S. DOE and a consortium of utilities, including PacifiCorp. PacifiCorp's participation in Solar II will allow the Company direct access to cost and performance data and will help to foster development and commercialization of this technology. Southern California Edison is acting as the project sponsor, and will operate the facility.

Cogeneration

Cogeneration refers to the use of thermal energy to drive industrial processes and, at the same time, produce electricity. The technology typically includes combustion turbines, steam turbines and reciprocating engines. Cogeneration employs a fully developed technology which can be implemented in some industrial and commercial facilities.

The price PacifiCorp must pay for cogenerated power will be determined by the marketplace. Each customer can negotiate a price for the potential power output which is competitive with what he or she could get from any other interested buyer in the marketplace. In addition, the price and availability of cogeneration will often be strongly influenced by the customer's choice of fuel and its forecasted prices.

The Company also has little control over when it can bring cogeneration on line and dispatch it, because the production of cogenerated power is driven by the commercial or industrial customer's processing needs -- not the company's power needs.

PacifiCorp has agreements in place with several large industrial customers who are also prime cogeneration hosts. Potential cogeneration resources are available from the six pulp and paper customers that are purchasing power from the Company under existing power sales contracts, and from several other large industrial customers. Discussions with several of these customers are currently underway to determine the optimum sizing and timing for the construction of the cogeneration facility and its pricing. Existing agreements with the pulp and paper customers give PacifiCorp the rights to develop cogeneration during the 7-year duration of the agreements.

The Company meets with each of these customers about once a month, and is actively negotiating an agreement with one of the pulp and paper customers. Another of the pulp and paper customers has determined to not pursue an agreement with the Company at this time. Ongoing study is being done with two other wood products customers. And several customers in the Utah division are actively negotiating with the Company. All of these projects could provide up to 600 MWa of additional resources, although 300 MWa is more likely.

Pulverized Coal Power Plants

The pulverized coal plant costs in RAMPP-2 are based on additional units being added at the Company's Hunter and Wyodak plant locations. Hunter Unit 4 and Wyodak Unit 2 were originally planned and licensed at these plant sites, but not built. These sites would have several advantages over an entirely new site due to existing fuel supply contracts, coal handling facilities, transmission for Hunter, and cost advantages from building another unit of the same size and major characteristics as previously built.

These plants use conventional technology based on a subcritical steam boiler that burns subbituminous coal. The technology provides for particulate removal, 90 percent removal of sulfur dioxide (SO_2), and low-nitrogen oxide burners. These controls would meet all applicable emission control requirements where Hunter 4 and Wyodak 2 are located.

Pulverized coal technology is considered mature. Permitting would require a minimum of three years at a new site, or two years at an existing site. After permitting, construction would take four to five years.

Although the Company used pulverized technology to estimate the cost of adding a unit to Hunter and Wyodak, the cost effectiveness of other coal options at these sites would be examined before committing to any new units.

For a possible Hunter Unit 4, additional coal reserves would probably be acquired. Current reserves are adequate to meet the needs of units 1-3 through the mid-1990s. The Company is currently examining the market for coal reserves, long-term contracts, and the spot market, to evaluate the most cost effective strategy. If reserves are acquired, the Company would use those locations to provide coal to the Hunter units. The currently available coal supply in Utah (reserves currently being mined) exceeds current needs. That excess supply should continue through the 1990s.

Additional information regarding coal technologies, their costs, and available coal supplies is available in the Supply-Side Resource Appendix.

Atmospheric Fluidized-Bed Combustion (AFBC)

These plants use crushed coal, which is burned along with limestone in an atmospheric pressure fluid-bed that is suspended by air blown in from below. The calcium in the limestone captures most of the sulfur released from the coal during combustion. Particulates are captured in a series of cyclones followed by a baghouse or electrostatic precipitator.

AFBC technology is in the early stages of commercialization. Several small plants, producing less than 100 MW each, have been built and are now operating. A number of larger systems are currently under construction. The technology should be available in sizes up to 250 MW by 1995.

Fluidized-bed combustion presents some major unresolved issues, including the high maintenance needed for the boiler system and the limestone required to capture the SO2. Construction lead times for AFBC are the same as that for conventional pulverized coal plants. The main advantages of the fluidized-bed boiler are its low nitrogen oxide emissions and its ability to burn a wider variety of coals.

Integrated Gasification Combined Cycle (IGCC)

In an IGCC plant, pulverized coal is fed into a gasifier where it reacts with oxygen to produce an intermediate BTU gas. After the gas passes through a cooling section, sulfur and nitrogen compounds are removed and the clean gas is fired in a combustion turbine. The hot exhaust gases generate steam in heat recovery boilers. The steam is used to drive a steam turbine generator. Major pollutants from an IGCC plant are less than those from a conventional coal plant. IGCC technology has been demonstrated at the Cool Water Plant in California and at major refineries. A number of commercial projects are now in the planning stages.

Low pollution levels are the major advantage of an IGCC plant, which makes it easier to permit and site than other coal options. IGCC might also be used as an add-on technology to natural-gas fired combustion turbines, if gas prices rise enough to make it cost competitive. Advanced versions of the gasifier concept are being developed, but are further into the future than the intermediate BTU systems.

Nuclear Power

New nuclear plants are not included in PacifiCorp's supply portfolio. The Company has serious concerns about the viability of new nuclear plant construction in the Pacific Northwest or any other part of the country in the near future. There are clear risks associated with high construction costs, uncertain regulatory treatment of those costs, and difficulty in licensing. While existing nuclear power plants may be an important resource option for utilities, the risks associated with new construction lead PacifiCorp to other alternatives in its choices for new resources.

Gas Price Assumptions

The gas prices assumed in RAMPP-2 are based on DRI's Mountain 1 Gas Price forecast for Electric Utilities. For the illustrative plans which do not call for higher gas prices, a 1991 starting price of $1.65/mmbtu (based on experience in the gas markets) is used. For 1992 through 2011 the price escalation is based on the DRI forecast (9.94 percent nominal, 4.61 percent real). After 2011 the escalation rate is 5.1 percent nominal, 0 percent real. For the exceptions (the high forecast, and the high gas sensitivities) the 1991 starting price is $1.94/mmbtu. For 1992 through 2011 the price escalation is the same as the base cases. After 2011 the escalation rate is 8.63 percent nominal, 3.36 percent real.

PacifiCorp can access gas supplies from several regions. Canadian gas from British Columbia or Alberta can be delivered by Northwest Pipeline or Pacific Gas Transmission, while the Company's service territory in Wyoming and Utah includes several natural gas fields. Additional gas can be accessed from the San Juan basin. These production areas have some of the most productive, lowest cost, and largest known reserve gas fields in North America. The Rocky Mountain and Canadian suppliers compete across Northwest pipeline for the Pacific Northwest market. The Company found, when activating its Gadsby plant, that the cost of Canadian and Rocky Mountain gas is quite similar.

The Company may choose to locate some SCCTs in gas fields, or near gas transportation bottlenecks in order to take advantage of better fuel prices. The Company plans to use interruptible gas transportation with backup fuel stored on site. A gas-fired resource could need backup fuel due to the nature of natural gas production and transportation. Delivery uncertainty is due to the fact that gas transmission has little redundant backup. Thus, the ability to deliver can fall sharply with mechanical failures.

Distribution

Although specific distribution "resources" were not examined to determine their cost competitiveness with other resource options, efficiency investments are planned over the 20-year planning horizon. They are listed on Table 3-1. In addition, the Company's ongoing investments in distribution plant are evaluated for their efficiency gains. Every time distribution transformers are purchased, they are examined for the degree to which they control losses. Transformers are selected which have low resistance and low reactance so that the losses are lower. The size of conductor for each application is determined by evaluating the cost relative to resistance and reactance so that the total owning costs are minimized. Capacitors are selected to reduce losses on circuits. Phase balancing equipment is also selected to reduce losses.

PORTFOLIO EVALUATION

Each of the options in the existing system, DSR pool, and supply side resource pool, is evaluated based on the criteria discussed at the beginning of this chapter. The next chapter will discuss how the resources are combined into illustrative plans to meet system needs under a variety of future load forecasts, scenarios, and sensitivities.

ILLUSTRATIVE PLANS

Preparing a 20-year resource plan is a balancing act: A balance must be struck between customers' anticipated needs and the resources available. In seeking that balance, PacifiCorp considers a large set of characteristics for each resource, including but not limited to the following: cost and retail price impact, contribution to reliable service, contribution to efficiency, environmental risks, flexibility, contribution to diversity (including fuel type and location), fit with the system, peak and energy benefits, dispatchability, and whether it is a lost opportunity resource.

Given the amount of uncertainty that exists in the energy marketplace and in the economy, it is not realistic to produce a single blueprint for activities over the next 20 years. Instead, a host of possible futures must be considered. PacifiCorp has developed illustrative resource plans for a total of 26 forecasts, scenarios and sensitivities to address future uncertainty. Additionally, it is not necessary to develop a blueprint now for the next 20 years, because in two years, when the RAMPP process is repeated, two more years of updated information will be available to produce improved plans for a new 20-year period. The primary value in producing 20-year plans is twofold: to provide a long-term context for developing an action plan for utility activities in the next two years with an understanding of the long term implications of those actions; and to provide an overall perspective and consistent planning framework for making resource and market decisions over those two years.

This chapter explains how the resources identified in the portfolio are combined and applied to meet the needs associated with each of the possible futures. The resource plans represent efficient (least cost) resource expansions, but they are not optimizations in the strict mathematical sense. The illustrative plans in RAMPP-2 illustrate how the power system would grow, over time, using reasonable planning criteria under various future conditions.

The modeling approach used in RAMPP-2 illustrates the kind of results that can be expected when various assumptions about the future are tested. As with any analysis based on modeling, the results are limited by the model itself, its assumptions, and input data. Therefore, exact quantitative results are less meaningful than the general and consistent patterns.

MODELING APPROACH

A key tool used in assembling the RAMPP-2 illustrative plans is the Resource Integration Model (RIM). That model automates the process of selecting resources to achieve a dynamic balance for both capacity and energy. It evaluates potential resources in the portfolio based on lowest cost, and considers lead times in determining when a new resource can come on line. The model mimics a fundamental aspect of actual resource decisions -- they are made (in the model and in reality) without exact foreknowledge of future conditions but in anticipation of future needs.

each forecast, scenario, and sensitivity. For each year of the 20-year planning horizon, as the load forecast exceeds the level of existing resources for energy, winter peak, or summer peak, the model recognizes that new resources are needed. RIM integrates new demand and supply side resources to meet the forecasted level of system needs. Subsequent models analyze the power cost and financial results of each resource plan. This set of models was used interactively and in an interative manner, allowing reasonable planning judgments and strategic considerations, such as the Company's new environmental goal, to be incorporated into the planning process.

The RIM model logic flows in the following sequence. At the beginning of each year of the planning horizon, RIM compares the resources available in the base system, plus the resources that the model has already added, to the load forecast to determine how many additional resources are required. Resource planning includes two important criteria -- a capacity reserve margin and an energy margin. For these studies, the capacity reserve margin was targeted at 15 percent; the energy margin was targeted at 150-300 MWa. The energy margin is a planning tool to recognize transmission constraints that can at times impede the full transfer of energy from generation locations to load centers.

RIM develops scores for all the available resources based on their costs. The model calculates a combined energy and capacity cost for each resource. The model spreads a resource's capacity cost over the amount of energy needed by the system. The model makes sure that the amount of energy used to spread the fixed costs falls between the resource's minimum and maximum capacity factors.

RIM then selects and adds to the system the least-cost resource. Plant capacity factors play an important role in determining what resource will be most economical in a given situation. Plants with high expected capacity factors (base load units) are able to support higher fixed costs. Conversely, plants that are expected to operate at relatively low capacity factors (peaking units) cannot support as high a percentage of fixed costs, but may be able to support proportionately higher variable costs.

When the addition of a resource does not meet the entire forecasted load for a particular year, the model again scores the remaining resources, then selects and adds the next one. This process of scoring, selecting, and adding is repeated until the model has added enough resources for that year for the total resources to meet the level of forecasted needs. The model then examines all the resources it added, to see if any of the smaller resources could be delayed because larger resources are needed.

After the model has selected the new resources for a given year, the new system that has been created is used as the basis for evaluating additional resources in the next year. RIM compares the new level of system resources to the load forecast for the next year. It scores all the resources and selects resources as needed to meet system needs; then it moves on to the next year. The model continues to build on itself in this manner until it has created a resource plan for the entire 20-year period.

Once each of the illustrative resource plans for RAMPP-2 was completed, the impacts of that plan were analyzed. A power cost model was used to determine the level of total operating costs for the entire system with the addition of the resources identified in the plan, considering fuel and other operating costs, and nonfirm purchases and sales given a variety of possible hydro conditions. A simplified financial model was used to determine the financial impacts on the Company, and the price impacts on customers. It considered the annual operating costs and the estimated capital costs of the new resources along with those same costs for the existing resources. The results of the financial model are not meant to be absolute predictions; they simply suggest reasonable relative indicators of financial and price impacts over the next 20 years. It is not so important how many dollars in revenues are required to cover total system costs, but rather how those values change across different forecasts and sensitivities.

To develop the illustrative plans for the four forecasts, these models were used in an iterative and interactive fashion. The entire set of model results were examined, the planning criteria were adjusted, and the process was repeated. For the scenarios and sensitivities, the model was run with one modification -- pilot renewable projects were added in earlier than specified by the model. This adjustment to the model was made to support the Company's environmental goal.

Illustrative plans were produced for each of the following cases:

- The four forecasts,
- The four scenarios,
- The 18 sensitivities, including:

  Five environmental cost sensitivities,
  Six other uncertainties, and
  Seven load growth uncertainties.

The MH load growth level was used for all of the sensitivities. The other choice considered was the ML load growth. That level was eliminated because few resource additions are required under that forecast; thus it would not be a good indicator of how various factors affect resource choices.

Table 4-1 (twelve pages) summarizes the resource plans developed for each of the cases. Each column shows the year and the number of MWa (energy) of each type of resource added in that year. In a few cases, a SCCT is shown with a negative value. This means a simple cycle has been converted to a combined cycle combustion turbine. It is removed from the SCCT category and a CCCT is added.

Table 4-2 summarizes the major financial impacts of each case. The first column shows the 20-year net present value (NPV) of operating revenue. This can also be thought of as the net present value of the revenue requirement. For economy of description in the following discussion of the results for each of the illustrative plans, the 20-year NPV of operating revenue will be referred to as the "system cost." The second column shows the base unit cost (the average price to the retail customer) in real terms (i.e., adjusted for inflation) after 20 years. The base unit cost equals the operating revenue in the last year of the planning period divided by that year's actual energy sales. This is the amount of kWhs which will be sold, and excludes any kWhs not sold because of DSR activity. The third column shows the average growth rate for the real prices to customers during the 20 years. It shows the average rate of growth for retail prices. When "real growth" is zero, it means retail prices will grow at the same rate as inflation. Again, for economy of description, the base unit cost real growth rate will be referred to as "real price growth."

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Resources Added (MWa)

Table 4-1

	The Four Forecasts				The Four Scenarios			
	Low Forecast	Medium Low Forecast	Medium High Forecast Step 4	High Forecast Step 2	High Gas Price	Loss of Resource	CO2 Tax	Electrification
D.S. Lost Ops	1992 - 2	1992 - 2	1992 - 3	1992 - 4	1992 - 3	1992 - 3	1992 - 3	1992 - 4
D.S. Lost Ops	1993 - 3	1993 - 3	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 4
D.S. Lost Ops	1994 - 4	1994 - 5	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 6
D.S. Lost Ops	1995 - 5	1995 - 7	1995 - 9	1995 - 10	1995 - 9	1995 - 9	1995 - 9	1995 - 10
D.S. Lost Ops	1996 - 5	1996 - 7	1996 - 11	1996 - 13	1996 - 11	1996 - 11	1996 - 11	1996 - 13
D.S. Lost Ops	1997 - 5	1997 - 7	1997 - 11	1997 - 13	1997 - 11	1997 - 11	1997 - 11	1997 - 13
D.S. Lost Ops	1998 - 5	1998 - 7	1998 - 11	1998 - 13	1998 - 11	1998 - 11	1998 - 11	1998 - 13
D.S. Lost Ops	1999 - 5	1999 - 8	1999 - 12	1999 - 14	1999 - 12	1999 - 12	1999 - 12	1999 - 14
D.S. Lost Ops	2000 - 4	2000 - 7	2000 - 12	2000 - 14	2000 - 12	2000 - 12	2000 - 12	2000 - 14
D.S. Lost Ops	2001 - 4	2001 - 7	2001 - 12	2001 - 13	2001 - 12	2001 - 12	2001 - 12	2001 - 13
D.S. Lost Ops	2002 - 4	2002 - 7	2002 - 11	2002 - 13	2002 - 11	2002 - 11	2002 - 11	2002 - 13
D.S. Lost Ops	2003 - 4	2003 - 7	2003 - 11	2003 - 13	2003 - 11	2003 - 11	2003 - 11	2003 - 13
D.S. Lost Ops	2004 - 4	2004 - 7	2004 - 11	2004 - 13	2004 - 11	2004 - 11	2004 - 11	2004 - 13
D.S. Lost Ops	2005 - 4	2005 - 7	2005 - 10	2005 - 12	2005 - 10	2005 - 10	2005 - 10	2005 - 12
D.S. Lost Ops	2006 - 4	2006 - 7	2006 - 10	2006 - 12	2006 - 10	2006 - 10	2006 - 10	2006 - 12
D.S. Lost Ops	2007 - 4	2007 - 7	2007 - 10	2007 - 12	2007 - 10	2007 - 10	2007 - 10	2007 - 12
D.S. Lost Ops	2008 - 4	2008 - 7	2008 - 10	2008 - 12	2008 - 10	2008 - 10	2008 - 10	2008 - 12
D.S. Lost Ops	2009 - 4	2009 - 7	2009 - 10	2009 - 12	2009 - 10	2009 - 10	2009 - 10	2009 - 12
D.S. Lost Ops	2010 - 3	2010 - 7	2010 - 10	2010 - 12	2010 - 10	2010 - 10	2010 - 10	2010 - 12
D.S. Lost Ops	2011 - 3	2011 - 6	2011 - 10	2011 - 12	2011 - 10	2011 - 10	2011 - 10	2011 - 12
D.S. Options	1992 - 7	1992 - 8	1992 - 10	1992 - 12	1992 - 10	1992 - 10	1992 - 10	1992 - 12
D.S. Options	1993 - 5	1993 - 7	1993 - 10	1993 - 11	1993 - 10	1993 - 10	1993 - 10	1993 - 11
D.S. Options	1994 - 5	1994 - 9	1994 - 14	1994 - 17	1994 - 14	1994 - 14	1994 - 14	1994 - 17
D.S. Options	1995 - 5	1995 - 13	1995 - 20	1995 - 24	1995 - 20	1995 - 20	1995 - 20	1995 - 24
D.S. Options	1996 - 6	1996 - 20	1996 - 33	1996 - 39	1996 - 33	1996 - 33	1996 - 33	1996 - 39
D.S. Options	1997 - 7	1997 - 26	1997 - 43	1997 - 51	1997 - 43	1997 - 43	1997 - 43	1997 - 51
D.S. Options	1998 - 8	1998 - 33	1998 - 52	1998 - 60	1998 - 52	1998 - 52	1998 - 52	1998 - 60
D.S. Options	1999 - 8	1999 - 35	1999 - 51	1999 - 59	1999 - 51	1999 - 51	1999 - 51	1999 - 59
D.S. Options	2000 - 12	2000 - 36	2000 - 49	2000 - 57	2000 - 49	2000 - 49	2000 - 49	2000 - 57
D.S. Options	2001 - 18	2001 - 37	2001 - 45	2001 - 53	2001 - 45	2001 - 45	2001 - 45	2001 - 53
D.S. Options	2002 - 25	2002 - 38	2002 - 43	2002 - 50	2002 - 43	2002 - 43	2002 - 43	2002 - 50
D.S. Options	2003 - 27	2003 - 38	2003 - 41	2003 - 48	2003 - 41	2003 - 41	2003 - 41	2003 - 48
D.S. Options	2004 - 28	2004 - 37	2004 - 40	2004 - 48	2004 - 40	2004 - 40	2004 - 40	2004 - 48
D.S. Options	2005 - 28	2005 - 31	2005 - 37	2005 - 40	2005 - 37	2005 - 37	2005 - 37	2005 - 40
D.S. Options	2006 - 28	2006 - 25	2006 - 27	2006 - 32	2006 - 27	2006 - 27	2006 - 27	2006 - 32
D.S. Options	2007 - 28	2007 - 16	2007 - 16	2007 - 19	2007 - 16	2007 - 16	2007 - 16	2007 - 19
D.S. Options	2008 - 28	2008 - 13	2008 - 16	2008 - 18	2008 - 16	2008 - 16	2008 - 16	2008 - 18
D.S. Options	2009 - 28	2009 - 12	2009 - 14	2009 - 16	2009 - 14	2009 - 14	2009 - 14	2009 - 16
D.S. Options	2010 - 28	2010 - 11	2010 - 14	2010 - 16	2010 - 14	2010 - 14	2010 - 14	2010 - 16
D.S. Options	2011 - 26	2011 - 10	2011 - 13	2011 - 16	2011 - 13	2011 - 13	2011 - 13	2011 - 16
BPA Exchange	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26
BPA Exchange	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38
Cogen		2009 - 80	1995 - 80	1994 - 85	1995 - 80	1994 - 80	1995 - 80	1994 - 85
Cogen		2009 - 80	1995 - 80	1994 - 85	1995 - 80	1994 - 80	1995 - 80	1994 - 85
Cogen			1996 - 85	1994 - 80	1996 - 85	1994 - 85	1996 - 85	1994 - 85
Cogen			1996 - 85	1994 - 80	1996 - 85	1994 - 85	1996 - 85	1994 - 80
Cogen				1994 - 85		1995 - 85		1994 - 80
Cogen				1995 - 85		1995 - 85		1995 - 85
Cogen				2003 - 85				1995 - 85
Cogen				2003 - 85				
Cogen				2003 - 85				
Cogen				2004 - 85				
Cogen								
Cogen								
Cogen								

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Resources Added (MWa)

Table 4-1

	The Four Forecasts				The Four Scenarios			
	Low Forecast	Medium Low Forecast	Medium High Forecast Step 4	High Forecast Step 2	High Gas Price	Loss of Resource	CO2 Tax	Electrification
Geothermal		1998 - 11	1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45
Geothermal		1999 - 34	2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45
Geothermal			2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45
Geothermal				2005 - 45	2005 - 100		1999 - 100	
Geothermal				2006 - 45	2005 - 100		2001 - 100	
Geothermal				2007 - 45	2006 - 100		2002 - 100	
Geothermal				2008 - 45	2006 - 100		2003 - 100	
Geothermal								
Geothermal								
Geothermal								
Geothermal								
Geothermal								
Geothermal								
Geothermal								
Geothermal								
Wind		1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5
Wind		1997 - 10	1997 - 17	1997 - 17	1997 - 17	1997 - 17	1997 - 17	1997 - 17
Wind		2006 - 30	1998 - 16	1998 - 16	1998 - 16	1998 - 16	1998 - 16	1998 - 16
Wind		2010 - 30	1999 - 5	1999 - 5	1999 - 5	1999 - 5	1999 - 5	1999 - 5
Wind			2000 - 15	2000 - 15	2000 - 15	2000 - 15	2000 - 15	2000 - 15
Wind			2001 - 15	2001 - 15	2001 - 15	2001 - 15	2001 - 15	2001 - 15
Wind			2002 - 10	2002 - 10	2002 - 10	2002 - 10	2002 - 10	2002 - 10
Wind				2004 - 5				
Wind				2005 - 17				
Wind				2006 - 16				
Wind				2007 - 5				
Wind				2008 - 15				
Wind				2009 - 15				
Wind				2010 - 10				
Wind								
Wind								
Wind								
Wind								
Wind								
Wind								
Wind								
Wind								
Wind								
Wind								
Wind								
Wind								
Wind								
Small SC CT		2008 - 8		1997 - 4	1996 - 4	1997 - 8	1996 - 4	1998 - 4
Small SC CT		2010 - 8		1997 - 4	1996 - 4	1997 - 8	1996 - 4	1998 - 4
Small SC CT		2010 - 8		1998 - 4	1996 - 4	1997 - 8	1996 - 4	1998 - 4
Small SC CT		2011 - 8		1998 - 4	1997 - 4	2007 - 4	1997 - 4	1998 - 4
Small SC CT				2005 - 4	1997 - 4	2007 - 4	1997 - 4	1999 - 4
Small SC CT				2006 - 4	1997 - 4	2007 - 4	1997 - 4	1999 - 4
Small SC CT				2008 - 8	1999 - 8	2007 - 4	2010 - 8	1999 - 4
Small SC CT						2008 - 4		1999 - 4
Small SC CT						2008 - 4		
Small SC CT						2008 - 4		
Small SC CT						2008 - 4		
Small SC CT						2010 - 8		

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Resources Added (MWa)

Table 4-1

	The Four Forecasts				The Four Scenarios			
	Low Forecast	Medium Low Forecast	Medium High Forecast Step 4	High Forecast Step 2	High Gas Price	Loss of Resource	CO2 Tax	Electrification
Medium SC CT			1996 - 10	2000 - 20	1999 - 10	1997 - 20		
Medium SC CT			1997 - 10		2000 - 10	2007 - 20		
Medium SC CT			1999 - 20		2000 - 20			
Medium SC CT			1999 - 20					
Medium SC CT			2000 - 20					
Medium SC CT								
Medium SC CT								
Medium SC CT								
Medium SC CT								
Large SC CT		2011 - 31	1998 - 31	1996 - 31	1998 - 31	1998 - 31	1998 - 31	1996 - 31
Large SC CT		2011 - 16	1998 - 31	1998 - 31	1998 - 31	2002 - 31	1998 - 31	1998 - 31
Large SC CT		2011 - 16		2000 - 31	1999 - 31		2000 - 31	2010 - 31
Large SC CT				2003 - 31			2002 - 31	2010 - 31
Large SC CT				2006 - 31				2010 - 31
Large SC CT								
Large SC CT								
Large SC CT								
Large SC CT								
Large SC CT								
Large SC CT								
Large SC CT								
Medium CC CT		2011 - 64			2008 - 32		2008 - 64	2000 - 64
Medium CC CT					2009 - 32			
Medium CC CT								
Medium CC CT								
Medium CC CT								
Medium CC CT								
Medium CC CT								
Medium CC CT								
Large CC CT			1997 - 175	1996 - 175	1997 - 175	1996 - 175	1997 - 175	1996 - 175
Large CC CT			2001 - 175	1996 - 175		1996 - 175	2003 - 88	1996 - 175
Large CC CT			2002 - 175	1997 - 175		1999 - 175	2004 - 87	1997 - 175
Large CC CT			2003 - 175	1998 - 175		2001 - 175	2005 - 175	1997 - 175
Large CC CT			2005 - 175	1999 - 175		2006 - 175	2006 - 175	1999 - 175
Large CC CT			2006 - 175	2002 - 175		2008 - 175	2007 - 175	1999 - 175
Large CC CT			2009 - 175	2005 - 175		2009 - 175	2009 - 175	2002 - 175
Large CC CT			2010 - 175	2006 - 175		2010 - 175	2010 - 175	2003 - 175
Large CC CT			2011 - 175	2007 - 175		2011 - 175	2011 - 175	2003 - 175
Large CC CT			2011 - 88	2008 - 175		2011 - 88	2011 - 88	2003 - 88
Large CC CT				2009 - 175				2004 - 87
Large CC CT				2009 - 175				2004 - 175
Large CC CT				2010 - 175				2005 - 175
Large CC CT				2010 - 88				2005 - 175
Large CC CT				2011 - 87				2005 - 88
Large CC CT				2011 - 175				2006 - 87
Large CC CT				2011 - 88				2006 - 175
Large CC CT								2006 - 175
Large CC CT								2007 - 175
Large CC CT								2007 - 175
Large CC CT								2007 - 88
Large CC CT								2008 - 87
Large CC CT								2008 - 175
Large CC CT								2008 - 175
Large CC CT								2008 - 88

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Resources Added (MWa)

Table 4-1

	The Four Forecasts				The Four Scenarios			
	Low Forecast	Medium Low Forecast	Medium High Forecast Step 4	High Forecast Step 2	High Gas Price	Loss of Resource	CO2 Tax	Electrification
Large CC CT								2009 - 87
Large CC CT								2009 - 175
Large CC CT								2009 - 175
Large CC CT								2009 - 88
Large CC CT								2009 - 88
Large CC CT								2010 - 87
Large CC CT								2010 - 87
Large CC CT								2010 - 88
Large CC CT								2010 - 88
Large CC CT								2010 - 88
Large CC CT								2010 - 88
Large CC CT								2011 - 87
Large CC CT								2011 - 87
Large CC CT								2011 - 87
Large CC CT								2011 - 87
Large CC CT								2011 - 88
Large CC CT								2011 - 88
Large CC CT								2011 - 88
Large CC CT								2011 - 88
Wyodak 2					2001 - 192	2005 - 192		2002 - 192
Hunter 4			2007 - 300	2001 - 300	2002 - 300	2003 - 300		2001 - 300
AFB Coal					2007 - 188			
AFB Coal					2009 - 188			
AFB Coal					2010 - 188			
AFB Coal					2011 - 188			
IGCC Coal					2011 - 188			
IGCC Coal								
IGCC Coal								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								
Pumped Storage								

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Resources Added (MWa)

Table 4-1

	Environmental					Other Uncertainties			
	Environmental Level 1	Environmental Level 2	Environmental Level 3	Environmental Leve 3 with High Gas Price	Environmental Level 4	20% Less Cost of Renewables	New Renewables Only	30% Less DSR	30% More DSR
D.S. Lost Ops	1992 - 3	1992 - 3	1992 - 3	1992 - 3	1992 - 3	1992 - 3	1992 - 3	1992 - 2	1992 - 4
D.S. Lost Ops	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 3	1993 - 5
D.S. Lost Ops	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 4	1994 - 7
D.S. Lost Ops	1995 - 9	1995 - 9	1995 - 9	1995 - 9	1995 - 9	1995 - 9	1995 - 9	1995 - 6	1995 - 12
D.S. Lost Ops	1996 - 11	1996 - 11	1996 - 11	1996 - 11	1996 - 11	1996 - 11	1996 - 11	1996 - 8	1996 - 15
D.S. Lost Ops	1997 - 11	1997 - 11	1997 - 11	1997 - 11	1997 - 11	1997 - 11	1997 - 11	1997 - 8	1997 - 15
D.S. Lost Ops	1998 - 11	1998 - 11	1998 - 11	1998 - 11	1998 - 11	1998 - 11	1998 - 11	1998 - 8	1998 - 14
D.S. Lost Ops	1999 - 12	1999 - 12	1999 - 12	1999 - 12	1999 - 12	1999 - 12	1999 - 12	1999 - 8	1999 - 15
D.S. Lost Ops	2000 - 12	2000 - 12	2000 - 12	2000 - 12	2000 - 12	2000 - 12	2000 - 12	2000 - 8	2000 - 15
D.S. Lost Ops	2001 - 12	2001 - 12	2001 - 12	2001 - 12	2001 - 12	2001 - 12	2001 - 12	2001 - 8	2001 - 15
D.S. Lost Ops	2002 - 11	2002 - 11	2002 - 11	2002 - 11	2002 - 11	2002 - 11	2002 - 11	2002 - 8	2002 - 15
D.S. Lost Ops	2003 - 11	2003 - 11	2003 - 11	2003 - 11	2003 - 11	2003 - 11	2003 - 11	2003 - 8	2003 - 15
D.S. Lost Ops	2004 - 11	2004 - 11	2004 - 11	2004 - 11	2004 - 11	2004 - 11	2004 - 11	2004 - 8	2004 - 14
D.S. Lost Ops	2005 - 10	2005 - 10	2005 - 10	2005 - 10	2005 - 10	2005 - 10	2005 - 10	2005 - 7	2005 - 14
D.S. Lost Ops	2006 - 10	2006 - 10	2006 - 10	2006 - 10	2006 - 10	2006 - 10	2006 - 10	2006 - 7	2006 - 13
D.S. Lost Ops	2007 - 10	2007 - 10	2007 - 10	2007 - 10	2007 - 10	2007 - 10	2007 - 10	2007 - 7	2007 - 13
D.S. Lost Ops	2008 - 10	2008 - 10	2008 - 10	2008 - 10	2008 - 10	2008 - 10	2008 - 10	2008 - 7	2008 - 13
D.S. Lost Ops	2009 - 10	2009 - 10	2009 - 10	2009 - 10	2009 - 10	2009 - 10	2009 - 10	2009 - 7	2009 - 13
D.S. Lost Ops	2010 - 10	2010 - 10	2010 - 10	2010 - 10	2010 - 10	2010 - 10	2010 - 10	2010 - 7	2010 - 13
D.S. Lost Ops	2011 - 10	2011 - 10	2011 - 10	2011 - 10	2011 - 10	2011 - 10	2011 - 10	2011 - 7	2011 - 13
D.S. Options	1992 - 10	1992 - 10	1992 - 10	1992 - 10	1992 - 10	1992 - 10	1992 - 10	1992 - 7	1992 - 13
D.S. Options	1993 - 10	1993 - 10	1993 - 10	1993 - 10	1993 - 10	1993 - 10	1993 - 10	1993 - 7	1993 - 12
D.S. Options	1994 - 14	1994 - 14	1994 - 14	1994 - 14	1994 - 14	1994 - 14	1994 - 14	1994 - 10	1994 - 18
D.S. Options	1995 - 20	1995 - 20	1995 - 20	1995 - 20	1995 - 20	1995 - 20	1995 - 20	1995 - 14	1995 - 27
D.S. Options	1996 - 33	1996 - 33	1996 - 33	1996 - 33	1996 - 33	1996 - 33	1996 - 33	1996 - 23	1996 - 43
D.S. Options	1997 - 43	1997 - 43	1997 - 43	1997 - 43	1997 - 43	1997 - 43	1997 - 43	1997 - 30	1997 - 56
D.S. Options	1998 - 52	1998 - 52	1998 - 52	1998 - 52	1998 - 52	1998 - 52	1998 - 52	1998 - 36	1998 - 68
D.S. Options	1999 - 51	1999 - 51	1999 - 51	1999 - 51	1999 - 51	1999 - 51	1999 - 51	1999 - 36	1999 - 67
D.S. Options	2000 - 49	2000 - 49	2000 - 49	2000 - 49	2000 - 49	2000 - 49	2000 - 49	2000 - 35	2000 - 64
D.S. Options	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 32	2001 - 59
D.S. Options	2002 - 43	2002 - 43	2002 - 43	2002 - 43	2002 - 43	2002 - 43	2002 - 43	2002 - 30	2002 - 55
D.S. Options	2003 - 41	2003 - 41	2003 - 41	2003 - 41	2003 - 41	2003 - 41	2003 - 41	2003 - 29	2003 - 53
D.S. Options	2004 - 40	2004 - 40	2004 - 40	2004 - 40	2004 - 40	2004 - 40	2004 - 40	2004 - 28	2004 - 52
D.S. Options	2005 - 37	2005 - 37	2005 - 37	2005 - 37	2005 - 37	2005 - 37	2005 - 37	2005 - 26	2005 - 48
D.S. Options	2006 - 27	2006 - 27	2006 - 27	2006 - 27	2006 - 27	2006 - 27	2006 - 27	2006 - 19	2006 - 35
D.S. Options	2007 - 16	2007 - 16	2007 - 16	2007 - 16	2007 - 16	2007 - 16	2007 - 16	2007 - 11	2007 - 21
D.S. Options	2008 - 16	2008 - 16	2008 - 16	2008 - 16	2008 - 16	2008 - 16	2008 - 16	2008 - 11	2008 - 20
D.S. Options	2009 - 14	2009 - 14	2009 - 14	2009 - 14	2009 - 14	2009 - 14	2009 - 14	2009 - 10	2009 - 19
D.S. Options	2010 - 14	2010 - 14	2010 - 14	2010 - 14	2010 - 14	2010 - 14	2010 - 14	2010 - 10	2010 - 18
D.S. Options	2011 - 13	2011 - 13	2011 - 13	2011 - 13	2011 - 13	2011 - 13	2011 - 13	2011 - 9	2011 - 17
BPA Exchange	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26
BPA Exchange	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38
Cogen	1995 - 80	1995 - 80	1995 - 80	1995 - 80	1995 - 80	1995 - 80	1995 - 80	1995 - 80	1995 - 80
Cogen	1995 - 80	1996 - 80	1996 - 80	1996 - 85	1996 - 80	1995 - 80	1995 - 80	1995 - 80	1996 - 80
Cogen	1996 - 85	1996 - 85	1996 - 85	1996 - 85	1996 - 85	1996 - 85	1996 - 85	1996 - 85	1996 - 85
Cogen	1996 - 85	1996 - 85	1996 - 85	1996 - 80	1996 - 85	1996 - 85	1996 - 85	1996 - 85	1996 - 85
Cogen							1996 - 85		
Cogen							1997 - 85		
Cogen							1997 - 85		
Cogen							2006 - 85		
Cogen									
Cogen									
Cogen									

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Resources Added (MWa)

Table 4-1

	Environmental					Other Uncertainties			
	Environmental Level 1	Environmental Level 2	Environmental Level 3	Environmental Leve 3 with High Gas Price	Environmental Level 4	20% Less Cost of Renewables	New Renewables Only	30% Less DSR	30% More DSR
Cogen									
Cogen									
Geothermal	1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45
Geothermal	2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45
Geothermal	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45
Geothermal			2010 - 100	1999 - 100	1999 - 100	2001 - 100	2007 - 100		
Geothermal			2011 - 100	2001 - 100	2001 - 100	2002 - 100	2008 - 100		
Geothermal				2002 - 100	2002 - 100	2005 - 100	2008 - 100		
Geothermal				2003 - 100	2003 - 100	2007 - 100	2009 - 100		
Geothermal							2009 - 100		
Geothermal							2010 - 100		
Geothermal							2010 - 100		
Geothermal							2011 - 100		
Geothermal							2011 - 100		
Geothermal							2011 - 100		
Geothermal									
Geothermal									
Wind	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5
Wind	1997 - 17	1997 - 17	1997 - 17	1997 - 17	1997 - 17	1997 - 17	1997 - 17	1997 - 17	1997 - 17
Wind	1998 - 16	1998 - 16	1998 - 16	1998 - 16	1998 - 16	1998 - 16	1998 - 16	1998 - 16	1998 - 16
Wind	1999 - 5	1999 - 5	1999 - 5	1999 - 5	1999 - 5	1999 - 5	1999 - 5	1999 - 5	1999 - 5
Wind	2000 - 15	2000 - 15	2000 - 15	2000 - 15	2000 - 15	2000 - 15	2000 - 15	2000 - 15	2000 - 15
Wind	2001 - 15	2001 - 15	2001 - 15	2001 - 15	2001 - 15	2001 - 15	2001 - 15	2001 - 15	2001 - 15
Wind	2002 - 10	2002 - 10	2002 - 10	2002 - 10	2002 - 10	2002 - 10	2002 - 10	2002 - 10	2002 - 10
Wind				2011 - 52			1998 - 52		
Wind							1999 - 52		
Wind							1999 - 52		
Wind							1999 - 52		
Wind							2000 - 52		
Wind							2001 - 52		
Wind							2001 - 52		
Wind							2001 - 52		
Wind							2002 - 52		
Wind							2003 - 52		
Wind							2003 - 52		
Wind							2003 - 52		
Wind							2003 - 52		
Wind							2003 - 52		
Wind							2005 - 52		
Wind							2005 - 52		
Wind							2005 - 52		
Wind							2006 - 52		
Wind							2006 - 52		
Wind							2007 - 52		
Small SC CT	1996 - 4	1995 - 8	1995 - 8	1995 - 8	1995 - 8	1996 - 4		1996 - 4	1996 - 4
Small SC CT	1996 - 4	1996 - 4	1996 - 4	1996 - 4	1996 - 4	1996 - 4		1996 - 4	1996 - 4
Small SC CT	1996 - 4	1997 - 4	1997 - 4	1997 - 4	1997 - 4	1996 - 4		1996 - 4	1997 - 4
Small SC CT	1997 - 4	2010 - 8		2006 - 4	2009 - 8	1997 - 4		1996 - 4	1997 - 4
Small SC CT	1997 - 4	2010 - 8		2007 - 4		1997 - 4		1997 - 4	2001 - 4
Small SC CT	1997 - 4					1997 - 4		1997 - 4	2002 - 4
Small SC CT	1999 - 8					1999 - 8		1997 - 4	2003 - 8
Small SC CT	1999 - 8					1999 - 8		1997 - 4	2003 - 8
Small SC CT	1999 - 8					1999 - 8		1999 - 8	2003 - 4

PacifiCorp - RAMPP 2
Resources Added (MWa)
Table 4-1

	Environmental					Other Uncertainties			
	Environmental Level 1	Environmental Level 2	Environmental Level 3	Environmental Leve 3 with High Gas Price	Environmental Level 4	20% Less Cost of Renewables	New Renewables Only	30% Less DSR	30% More DSR
Small SC CT	2007 - 8					2010 - 4		1999 - 8	2003 - 8
Small SC CT						2011 - 4		1999 - 8	2004 - 4
Small SC CT								2006 - 8	2011 - 8
Medium SC CT	1999 - 20			1998 - 20	1998 - 20	1999 - 20		1999 - 20	2011 - 10
Medium SC CT	2000 - 20			2003 - 20		2001 - 20		2004 - 20	2011 - 10
Medium SC CT	2011 - 10					2005 - 20		2006 - 10	
Medium SC CT						2010 - 20		2007 - 10	
Medium SC CT								2010 - 10	
Medium SC CT								2010 - 10	
Medium SC CT								2011 - 10	
Medium SC CT								2011 - 10	
Medium SC CT								2011 - 10	
Large SC CT	1998 - 31	1997 - 31	1997 - 31	1997 - 31	1997 - 31	1998 - 31		1998 - 31	1997 - 31
Large SC CT	1998 - 31	1998 - 31	1998 - 31	2000 - 31	2000 - 31	1998 - 31		1998 - 31	1998 - 31
Large SC CT		2000 - 31	2000 - 31	2000 - 31	2000 - 31	2000 - 31		1999 - 16	2000 - 31
Large SC CT				2003 - 31	2006 - 31	2001 - 16		2000 - 15	2005 - 31
Large SC CT				2003 - 31	2008 - 31	2002 - 15		2000 - 31	2005 - 31
Large SC CT				2003 - 31				2003 - 31	2005 - 16
Large SC CT				2004 - 31				2003 - 31	2005 - 16
Large SC CT								2004 - 16	2005 - 31
Large SC CT								2005 - 16	2006 - 15
Large SC CT									2006 - 15
Large SC CT									
Large SC CT									
Medium CC CT		1999 - 64	1999 - 64		2010 - 64			2011 - 64	
Medium CC CT					2011 - 64				
Medium CC CT									
Medium CC CT									
Medium CC CT									
Medium CC CT									
Medium CC CT									
Medium CC CT									
Large CC CT	1997 - 175	1997 - 175	1997 - 175	1997 - 175	1997 - 175	1997 - 175		1997 - 175	1997 - 175
Large CC CT	2001 - 175	2001 - 175	2001 - 175	2008 - 175	2003 - 175	2008 - 175		2002 - 88	2003 - 175
Large CC CT	2002 - 175	2002 - 175	2002 - 175		2005 - 175	2009 - 175		2003 - 87	2008 - 88
Large CC CT	2003 - 175	2003 - 175	2003 - 175		2006 - 175	2010 - 175		2003 - 175	2009 - 87
Large CC CT	2005 - 175	2005 - 175	2005 - 175		2007 - 175	2011 - 175		2007 - 175	2009 - 175
Large CC CT	2006 - 175	2006 - 175	2006 - 175		2009 - 175	2011 - 88		2008 - 175	2010 - 175
Large CC CT	2007 - 88	2007 - 88	2007 - 88		2010 - 175			2009 - 175	2011 - 175
Large CC CT	2008 - 87	2008 - 87	2008 - 87		2011 - 175			2010 - 175	
Large CC CT	2008 - 88	2008 - 175	2008 - 175					2011 - 175	
Large CC CT	2009 - 87	2009 - 175	2009 - 175						
Large CC CT	2009 - 88	2010 - 88	2011 - 175						
Large CC CT	2010 - 87	2011 - 87							
Large CC CT	2010 - 175	2011 - 175							
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									

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Resources Added (MWa)

Table 4-1

	Environmental					Other Uncertainties			
	Environmental Level 1	Environmental Level 2	Environmental Level 3	Environmental Leve 3 with High Gas Price	Environmental Level 4	20% Less Cost of Renewables	New Renewables Only	30% Less DSR	30% More DSR
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
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Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Wyodak 2	2011 - 192			2007 - 192		2006 - 192		2001 - 192	2001 - 192
Hunter 4				2005 - 300		2003 - 300		2005 - 300	2006 - 300
AFB Coal									
AFB Coal									
AFB Coal									
AFB Coal									
IGCC Coal				2009 - 188					
IGCC Coal				2010 - 188					
IGCC Coal				2011 - 188					
Pumped Storage							1997 - (13)		
Pumped Storage							1998 - (13)		
Pumped Storage							1998 - (13)		
Pumped Storage							2000 - (13)		
Pumped Storage							2000 - (13)		
Pumped Storage							2002 - (13)		
Pumped Storage							2002 - (13)		
Pumped Storage							2003 - (13)		
Pumped Storage							2003 - (13)		
Pumped Storage							2006 - (13)		
Pumped Storage							2006 - (13)		
Pumped Storage							2006 - (13)		
Pumped Storage							2010 - (13)		
Pumped Storage							2010 - (13)		

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Resources Added (MWa)

Table 4-1

	Other Uncertainties		Load Uncertainty						
	Average Hydro Conditions	10% Less Thermal	Medium Low Forecast; Low Actuals	Medium High Forecast; Medium Low Actuals	Medium Low Forecast; Medium High Actuals	High Forecast; Medium High Actuals	Medium High Forecast; High Actuals	Medium High Forecast; High Excursion	Medium High Forecast; High short Excursion
D.S. Lost Ops	1992 - 3	1992 - 3	1992 - 2	1992 - 2	1992 - 3	1992 - 3	1992 - 4	1992 - 4	1992 - 4
D.S. Lost Ops	1993 - 4	1993 - 14	1993 - 3	1993 - 3	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 4
D.S. Lost Ops	1994 - 6	1994 - 6	1994 - 4	1994 - 5	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 6
D.S. Lost Ops	1995 - 9	1995 - 9	1995 - 5	1995 - 7	1995 - 9	1995 - 9	1995 - 10	1995 - 10	1995 - 10
D.S. Lost Ops	1996 - 11	1996 - 11	1996 - 5	1996 - 7	1996 - 11	1996 - 11	1996 - 13	1996 - 13	1996 - 13
D.S. Lost Ops	1997 - 11	1997 - 11	1997 - 5	1997 - 7	1997 - 11	1997 - 11	1997 - 13	1997 - 13	1997 - 7
D.S. Lost Ops	1998 - 11	1998 - 11	1998 - 1	1998 - 5	1998 - 14	1998 - 10	1998 - 13	1998 - 5	1998 - 11
D.S. Lost Ops	1999 - 12	1999 - 12	1999 - 4	1999 - 8	1999 - 11	1999 - 12	1999 - 14	1999 - 12	1999 - 12
D.S. Lost Ops	2000 - 12	2000 - 12	2000 - 4	2000 - 8	2000 - 11	2000 - 12	2000 - 13	2000 - 12	2000 - 12
D.S. Lost Ops	2001 - 12	2001 - 12	2001 - 4	2001 - 8	2001 - 11	2001 - 12	2001 - 13	2001 - 12	2001 - 12
D.S. Lost Ops	2002 - 11	2002 - 11	2002 - 4	2002 - 8	2002 - 11	2002 - 12	2002 - 13	2002 - 11	2002 - 11
D.S. Lost Ops	2003 - 11	2003 - 11	2003 - 4	2003 - 8	2003 - 10	2003 - 12	2003 - 13	2003 - 11	2003 - 11
D.S. Lost Ops	2004 - 11	2004 - 11	2004 - 4	2004 - 7	2004 - 10	2004 - 11	2004 - 13	2004 - 11	2004 - 11
D.S. Lost Ops	2005 - 10	2005 - 10	2005 - 4	2005 - 7	2005 - 11	2005 - 11	2005 - 12	2005 - 10	2005 - 10
D.S. Lost Ops	2006 - 10	2006 - 10	2006 - 4	2006 - 7	2006 - 10	2006 - 10	2006 - 11	2006 - 10	2006 - 10
D.S. Lost Ops	2007 - 10	2007 - 10	2007 - 4	2007 - 7	2007 - 10	2007 - 10	2007 - 11	2007 - 10	2007 - 10
D.S. Lost Ops	2008 - 10	2008 - 10	2008 - 4	2008 - 7	2008 - 10	2008 - 10	2008 - 11	2008 - 10	2008 - 10
D.S. Lost Ops	2009 - 10	2009 - 10	2009 - 4	2009 - 7	2009 - 10	2009 - 10	2009 - 11	2009 - 10	2009 - 10
D.S. Lost Ops	2010 - 10	2010 - 10	2010 - 4	2010 - 7	2010 - 10	2010 - 10	2010 - 11	2010 - 10	2010 - 10
D.S. Lost Ops	2011 - 10	2011 - 10	2011 - 4	2011 - 7	2011 - 9	2011 - 10	2011 - 12	2011 - 10	2011 - 10
D.S. Options	1992 - 10	1992 - 10	1992 - 7	1992 - 8	1992 - 10	1992 - 10	1992 - 12	1992 - 12	1992 - 12
D.S. Options	1993 - 10	1993 - 10	1993 - 5	1993 - 7	1993 - 10	1993 - 10	1993 - 11	1993 - 11	1993 - 11
D.S. Options	1994 - 14	1994 - 14	1994 - 5	1994 - 9	1994 - 14	1994 - 14	1994 - 17	1994 - 17	1994 - 17
D.S. Options	1995 - 20	1995 - 20	1995 - 5	1995 - 13	1995 - 20	1995 - 20	1995 - 24	1995 - 24	1995 - 24
D.S. Options	1996 - 33	1996 - 33	1996 - 6	1996 - 20	1996 - 33	1996 - 33	1996 - 39	1996 - 39	1996 - 39
D.S. Options	1997 - 43	1997 - 43	1997 - 7	1997 - 26	1997 - 43	1997 - 43	1997 - 51	1997 - 51	1997 - 27
D.S. Options	1998 - 52	1998 - 52	1998 - 55	1998 - 58	1998 - 20	1998 - 53	1998 - 58	1998 - 28	1998 - 52
D.S. Options	1999 - 51	1999 - 51	1999 - 27	1999 - 40	1999 - 45	1999 - 51	1999 - 60	1999 - 51	1999 - 51
D.S. Options	2000 - 49	2000 - 49	2000 - 28	2000 - 38	2000 - 47	2000 - 49	2000 - 58	2000 - 49	2000 - 49
D.S. Options	2001 - 45	2001 - 45	2001 - 29	2001 - 35	2001 - 48	2001 - 45	2001 - 53	2001 - 45	2001 - 45
D.S. Options	2002 - 43	2002 - 43	2002 - 30	2002 - 33	2002 - 49	2002 - 43	2002 - 50	2002 - 43	2002 - 43
D.S. Options	2003 - 41	2003 - 41	2003 - 30	2003 - 32	2003 - 49	2003 - 41	2003 - 48	2003 - 41	2003 - 41
D.S. Options	2004 - 40	2004 - 40	2004 - 29	2004 - 31	2004 - 48	2004 - 41	2004 - 47	2004 - 40	2004 - 40
D.S. Options	2005 - 37	2005 - 37	2005 - 24	2005 - 29	2005 - 40	2005 - 34	2005 - 43	2005 - 37	2005 - 37
D.S. Options	2006 - 27	2006 - 27	2006 - 20	2006 - 21	2006 - 32	2006 - 28	2006 - 31	2006 - 27	2006 - 27
D.S. Options	2007 - 16	2007 - 16	2007 - 13	2007 - 12	2007 - 21	2007 - 16	2007 - 18	2007 - 16	2007 - 16
D.S. Options	2008 - 16	2008 - 16	2008 - 10	2008 - 12	2008 - 17	2008 - 15	2008 - 18	2008 - 16	2008 - 16
D.S. Options	2009 - 14	2009 - 14	2009 - 9	2009 - 11	2009 - 15	2009 - 14	2009 - 17	2009 - 14	2009 - 14
D.S. Options	2010 - 14	2010 - 14	2010 - 8	2010 - 11	2010 - 14	2010 - 14	2010 - 16	2010 - 14	2010 - 14
D.S. Options	2011 - 13	2011 - 13	2011 - 8	2011 - 10	2011 - 13	2011 - 14	2011 - 15	2011 - 13	2011 - 13
BPA Exchange	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26
BPA Exchange	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38
Cogen	1996 - 80	1994 - 80		1996 - 80	2001 - 80	1994 - 85	1995 - 80	1995 - 80	1995 - 80
Cogen	1996 - 85	1995 - 80		1996 - 80	2001 - 80	1994 - 85	1995 - 80	1996 - 85	1996 - 85
Cogen	1997 - 80	1995 - 85			2001 - 85	1995 - 80	1996 - 85	1996 - 85	1996 - 85
Cogen	1997 - 85	1995 - 85			2001 - 85	1995 - 80	1996 - 85	1996 - 85	1996 - 85
Cogen						1995 - 85	1996 - 85	1996 - 85	1996 - 85
Cogen						1996 - 85	1996 - 85	1996 - 80	1996 - 80
Cogen									
Cogen									
Cogen									
Cogen									
Cogen									

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Resources Added (MWa)

Table 4-1

	Other Uncertainties		Load Uncertainty						
	Average Hydro Conditions	10% Less Thermal	Medium Low Forecast; Low Actuals	Medium High Forecast; Medium Low Actuals	Medium Low Forecast; Medium High Actuals	High Forecast; Medium High Actuals	Medium High Forecast; High Actuals	Medium High Forecast; High Excursion	Medium High Forecast; High short Excursion
Cogen									
Cogen									
Geothermal	1999 - 45	1999 - 45	1998 - 11	1998 - 11	1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45
Geothermal	2000 - 45	2000 - 45	1999 - 34	1999 - 34	2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45
Geothermal	2001 - 45	2001 - 45			2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Geothermal									
Wind	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5
Wind	1997 - 17	1997 - 17	1997 - 10	1997 - 17	1997 - 10	1997 - 17	1997 - 17	1997 - 17	1997 - 17
Wind	1998 - 16	1998 - 16		1998 - 16	1997 - 30	1998 - 16	1998 - 16	1998 - 16	1998 - 16
Wind	1999 - 5	1999 - 5			1999 - 7	1999 - 5	1999 - 5	1999 - 5	1999 - 5
Wind	2000 - 15	2000 - 15			2000 - 16	2000 - 15	2000 - 15	2000 - 15	2000 - 15
Wind	2001 - 15	2001 - 15				2001 - 15	2001 - 15	2001 - 15	2001 - 15
Wind	2002 - 10	2002 - 10				2002 - 10	2002 - 10	2002 - 10	2002 - 10
Wind									
Wind									
Wind									
Wind									
Wind									
Wind									
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Wind									
Wind									
Wind									
Wind									
Wind									
Wind									
Wind									
Wind									
Wind									
Wind									
Wind									
Wind									
Small SC CT	2000 - 4	2000 - 4				1997 - 8	2003 - 8	1995 - 8	1995 - 8
Small SC CT	2001 - 4	2001 - 4				1997 - 4	2003 - 4	1999 - 8	1999 - 8
Small SC CT	2008 - 8	2008 - 8				1997 - 4	2003 - 4	1999 - 8	1999 - 8
Small SC CT	2008 - 8	2008 - 8				1997 - 4	2003 - 4	1999 - 4	1999 - 4
Small SC CT	2010 - 8	2008 - 8				1998 - 4	2004 - 4	1999 - 4	1999 - 4
Small SC CT	2010 - 8	2009 - 8				1998 - 4	2004 - 4	2000 - 4	2000 - 4
Small SC CT		2009 - 4				1998 - 4	2004 - 4	2000 - 4	2000 - 4
Small SC CT		2009 - 4				2001 - 4	2011 - 8		2006 - 4
Small SC CT		2010 - 4				2002 - 4			2006 - 4

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Resources Added (MWa)

Table 4-1

	Other Uncertainties		Load Uncertainty						
	Average Hydro Conditions	10% Less Thermal	Medium Low Forecast; Low Actuals	Medium High Forecast; Medium Low Actuals	Medium Low Forecast; Medium High Actuals	High Forecast; Medium High Actuals	Medium High Forecast; High Actuals	Medium High Forecast; High Excursion	Medium High Forecast; High short Excursion
Small SC CT		2010 - 4							2006 - 8
Small SC CT									2007 - 4
Small SC CT									2007 - 4
Medium SC CT	2003 - 20	1999 - 10			1999 - 20		1999 - 20	1999 - 20	1999 - 20
Medium SC CT		2000 - 10			1999 - 20		2000 - 20	2000 - 20	2000 - 20
Medium SC CT		2000 - 20			2003 - 20		2000 - 20		2003 - 20
Medium SC CT		2009 - 10							2004 - 20
Medium SC CT		2010 - 10							
Medium SC CT									
Medium SC CT									
Medium SC CT									
Medium SC CT									
Large SC CT	1996 - 31	2000 - 31		1998 - 31	1996 - 16	1999 - 31	1996 - 31	1997 - 31	1997 - 31
Large SC CT	1996 - 31	2000 - 16			1996 - 16	2001 - 31	1998 - 31	1998 - 31	1998 - 31
Large SC CT	1997 - 31	2001 - 16			1996 - 16		1998 - 31	1998 - 31	1998 - 31
Large SC CT	1998 - 31	2010 - 31			1997 - 16		1999 - 31	1999 - 31	1999 - 31
Large SC CT	1999 - 31				1997 - 16		1999 - 31	2000 - 16	2003 - 31
Large SC CT	2000 - 16				1997 - 16		2000 - 16	2000 - 16	2003 - 31
Large SC CT	2001 - 16				2003 - 31		2001 - 16	2001 - 16	2003 - 31
Large SC CT					2003 - 31		2001 - 31	2001 - 16	
Large SC CT					2003 - 31			2010 - 31	
Large SC CT					2003 - 31				
Large SC CT									
Large SC CT									
Medium CC CT		2011 - 64						2004 - 64	
Medium CC CT									
Medium CC CT									
Medium CC CT									
Medium CC CT									
Medium CC CT									
Medium CC CT									
Medium CC CT									
Large CC CT	2002 - 175	1996 - 175			2001 - 175	1996 - 175	1997 - 175	1997 - 175	1997 - 175
Large CC CT	2003 - 88	1996 - 175			2001 - 175	1998 - 175	2001 - 175	2001 - 175	2002 - 175
Large CC CT	2004 - 87	1997 - 175			2002 - 175	2007 - 175	2003 - 175	2002 - 175	2007 - 175
Large CC CT	2005 - 175	1999 - 175			2008 - 175	2008 - 175	2004 - 175	2003 - 175	2008 - 175
Large CC CT	2006 - 175	2003 - 88			2009 - 175	2009 - 175	2005 - 175	2003 - 175	2009 - 175
Large CC CT	2007 - 88	2004 - 87			2010 - 175	2010 - 175	2005 - 175	2006 - 175	2010 - 175
Large CC CT	2008 - 87	2005 - 175			2011 - 175	2011 - 175	2006 - 175	2006 - 175	2011 - 175
Large CC CT	2010 - 88	2006 - 175			2011 - 88	2011 - 88	2007 - 175	2007 - 175	2011 - 88
Large CC CT	2011 - 87	2006 - 88					2007 - 175	2007 - 88	
Large CC CT	2011 - 175	2007 - 87					2008 - 175	2008 - 87	
Large CC CT		2009 - 175					2008 - 175	2008 - 175	
Large CC CT		2010 - 175					2009 - 175	2008 - 88	
Large CC CT		2011 - 175					2009 - 175	2009 - 87	
Large CC CT							2010 - 175	2009 - 175	
Large CC CT							2010 - 175	2009 - 175	
Large CC CT							2010 - 88	2010 - 175	
Large CC CT							2011 - 87	2010 - 175	
Large CC CT							2011 - 175	2011 - 175	
Large CC CT							2011 - 175	2011 - 175	
Large CC CT								2011 - 175	
Large CC CT									

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Resources Added (MWa)

Table 4-1

	Other Uncertainties		Load Uncertainty						
	Average Hydro Conditions	10% Less Thermal	Medium Low Forecast; Low Actuals	Medium High Forecast; Medium Low Actuals	Medium Low Forecast; Medium High Actuals	High Forecast; Medium High Actuals	Medium High Forecast; High Actuals	Medium High Forecast; High Excursion	Medium High Forecast; High short Excursion
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
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Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Large CC CT									
Wyodak 2	2001 - 192	2001 - 192		2003 - 192	2005 - 192	2003 - 192	2001 - 192	2001 - 192	2001 - 192
Hunter 4	2009 - 300	2002 - 300		2005 - 300	2006 - 300	2005 - 300	2002 - 300	2005 - 300	2005 - 300
AFB Coal									
AFB Coal									
AFB Coal									
AFB Coal									
IGCC Coal									
IGCC Coal									
IGCC Coal									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									
Pumped Storage									

PacifiCorp - RAMPP 2
Financial Summary of Illustrative Plans
Table 4-2

	20-year NPV Op. Rev. ($MM)	Base Unit Cost: Real Price After 20 Years (mills/kWh)	Base Unit Cost: Ave. 20-Year Growth Real %
FORECASTS			
Low Forecast	23,724	36.9	-1.15
Medium-Low Forecast	26,210	39.8	-0.75
Medium-High Forecast, Step 1	31,484	45.0	-0.11
Medium-High Forecast, Step 2	31,644	45.4	-0.07
Medium-High Forecast, Step 3	31,332	45.1	-0.09
Medium-High, Step 4	31,319	44.8	-0.13
High, Step 1	36,393	49.3	0.38
High, Step 2	36,125	48.8	0.33
SCENARIOS			
Electrification Scenario	39,940	53.4	0.72
Loss of Resources Scenario	31,931	45.5	-0.05
High Gas Prices Scenario	31,944	47.4	0.17
CO2 Tax Scenario	31,731	45.4	-0.06
ENVIRONMENTAL			
Environmental Level 1	31,332	45.1	-0.09
Environmental Level 2	31,306	45.1	-0.09
Environmental Level 3	31,310	45.2	-0.08
Environ. Level 3 with High Gas Prices	32,098	47.6	0.19
Environmental Level 4	31,732	45.8	-0.02
OTHER UNCERTAINTIES			
Renewables 20% Less Cost	31,621	45.3	-0.07
New Renewables Only	33,782	52.7	0.73
DSR Yield Plus 30%	31,123	45.4	-0.06
DSR Yield Minus 30%	32,148	45.8	-0.02
Average Hydro Conditions	31,454	45.5	-0.05
10% Less Thermal	32,987	48.0	0.24
LOAD UNCERTAINTY			
Med-Low Forecast, Low Actuals	23,956	38.5	-0.93
Med-High Forecast, Med-Low Actuals	26,847	40.9	-0.61
Med-Low Forecast, Med-High Actuals	31,666	45.9	0.00
High Forecast, Med-High Actuals	31,419	44.9	-0.11
Med-High Forecast, High Actuals	36,067	50.2	0.47
Med-High Forecast, High Excursion	34,746	45.1	-0.09
Med-High Forecast, High Short Excursion	33,287	47.6	0.19

The CO2 Tax Scenario results (with the tax) should be: 20-yr NPV Op Rev of $46,114; real price after 20 years of 70.3 mills/kWh; growth rate of 2.3 percent. System costs increase by $14.8 billion over MH4; $650 million due to resource choice costs. (See page 87)

PacifiCorp - RAMPP 2
Emissions from Illustrative Plans
Table 4-3

	Percent Increase in Emissions from 1991 - 2011			Percent Increase in GWH Requirements from 1991 to 2011
FORECASTS	CO2	SO2	NOX	
Low Forecast	5.2	3.0	-17.6	6
Medium-Low Forecast	12.5	11.0	-13.6	20
Medium-High Forecast, Step 1	35.6	14.1	-5.4	58
Medium-High Forecast, Step 2	33.9	13.6	-5.7	58
Medium-High Forecast, Step 3	32.4	14.0	-9.0	58
Medium-High, Step 4	32.2	12.4	-8.3	58
High, Step 1	46.8	14.1	-4.4	88
High, Step 2	44.6	12.8	-6.7	88
SCENARIOS				
Electrification Scenario	66.5	12.7	-4.0	127
Loss of Resources Scenario	36.0	14.0	-5.3	58
High Gas Prices Scenario	41.1	16.9	-2.2	58
CO2 Tax Scenario	26.9	12.5	-12.0	58
ENVIRONMENTAL				
Environmental Level 1	32.2	12.4	-8.3	58
Environmental Level 2	30.0	12.1	-12.0	58
Environmental Level 3	29.0	12.7	-11.7	58
Environ. Level 3 with High Gas Prices	37.3	15.8	-3.2	58
Environmental Level 4	26.1	11.3	-12.6	58
OTHER UNCERTAINTIES				
Renewables 20% Less Cost	31.2	14.4	-5.5	58
New Renewables Only	14.9	11.2	-12.5	58
DSR Yield Plus 30%	32.2	13.9	-5.7	58
DSR Yield Minus 30%	36.2	14.8	-5.5	58
Average Hydro Conditions	33.9	14.0	-5.4	58
10% Less Thermal	38.5	13.7	-5.4	58
LOAD UNCERTAINTY				
Med-Low Forecast, Low Actuals	5.0	2.7	-17.8	7
Med-High Forecast, Med-Low Actuals	18.6	11.0	-7.7	23
Med-Low Forecast, Med-High Actuals	33.8	13.8	-5.7	58
High Forecast, Med-High Actuals	34.1	14.2	-5.2	58
Med-High Forecast, High Actuals	46.8	14.1	-4.4	88
Med-High Forecast, High Excursion	48.2	14.9	-4.1	85
Med-High Forecast, High Short Excursion	39.0	13.9	-5.1	66

The pattern of results in the NPV of Op Rev (system cost) column do not always correspond to the pattern of results in the base unit cost real growth rate (real price growth) column. This is because the NPV results are highly influenced by costs that occur early in the 20 years, and are less influenced by costs that occur late in the 20 years. The base unit cost growth rate, on the other hand, compares base unit costs at the starting point and end point of the studies.

Table 4-3 shows the percentage increase in emissions comparing 1991 to 2011 for all of the cases. The increase in each of four emissions (CO2, SO2, NOx and TSP) is provided along with the increase in gigawatt hours (GWh) requirements. TSP represents total suspended particulates. Emissions grow more slowly than GWh requirements in all cases, but the degree of improvement in emission output relative to GWh requirements varies across the cases.

The Results Technical Appendix includes tables which provide additional details for each of the model runs. Tables for each run include: a graph showing resource additions across time, financial results on a year-by-year basis, energy additions for each year and the resulting load/resource balance, winter capacity additions for each year and the resulting load/resource balance, and summer capacity additions for each year and the resulting load/resource balance. From these tables, the reader can determine the contribution of each resource addition to energy and peaking needs.

FOUR FORECASTS: ILLUSTRATIVE PLANS

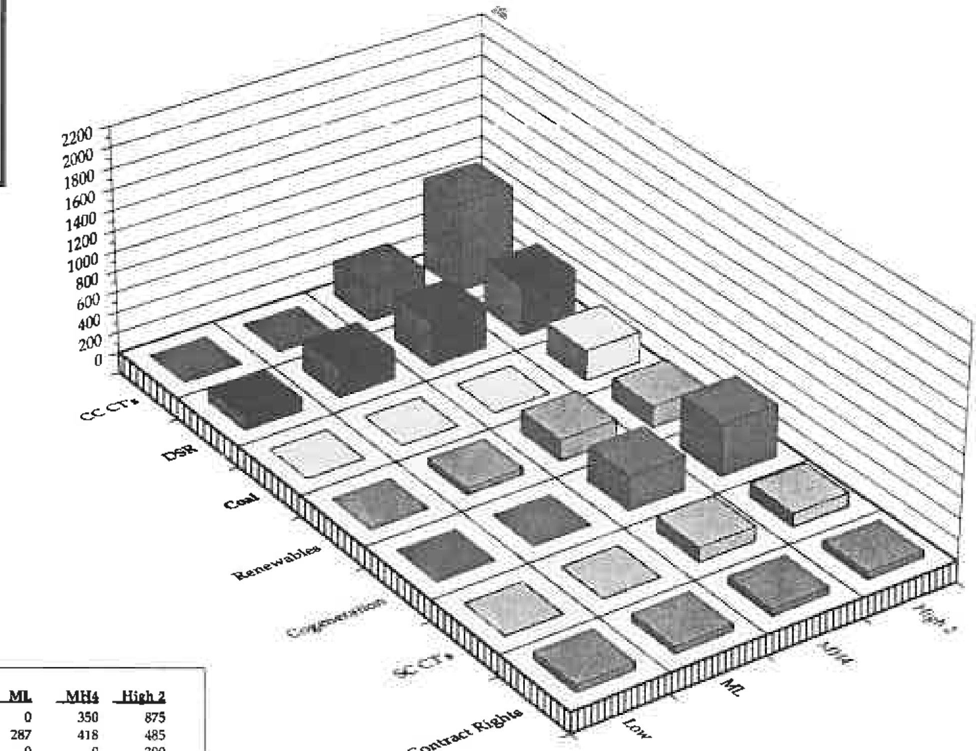
Graph 4-4 shows the resources that would be added by the year 2001 and by the year 2011 for all four forecasts. This provides a summary picture of how the resource additions increase with each higher level forecast of load growth. The results are described in energy terms, for economy of presentation. This enabled the descriptions to flow more efficiently, rather than listing the energy, winter peak, and summer peak results for each plan. Each resource plan was selected based on the contribution of each resource to energy, as well as winter and summer peaking needs. The Results Appendix provides equivalent detailed information for energy, winter peak and summer peak.

Low Forecast

Graph 4-5 shows the resource additions for the 20 years under a low load growth forecast. Under the low forecast, loads would increase at only 0.5 percent per year, for a total addition of 520 MWa over the 20 years. Resource needs are reduced by the expiration of existing long term sales agreements with other utilities. The needs are more than met by 473 MWa of demand-side resources and by exercising the BPA Entitlement Agreement at the latest opportunity in 1997. The demand side additions are motivated by a strategy of capturing lost opportunities and maintaining minimal viable programs. Consequently, a substantial energy surplus develops through the planning horizon in this case. Secondary wholesale sales help to mitigate the cost impacts of this surplus. Firm wholesale sales could also serve this purpose, but no attempt was made to simulate long term transactions. Real price growth and emissions would be the lower in this case than in any of the other 25 futures. Retail prices would decrease by 1.15 percent in real terms. Although emissions would be low, they would increase at almost the same rate as total GWh requirements increase. In all of the other cases, emissions increase at a significantly lower rate than do GWh requirements.

Graph 4-4

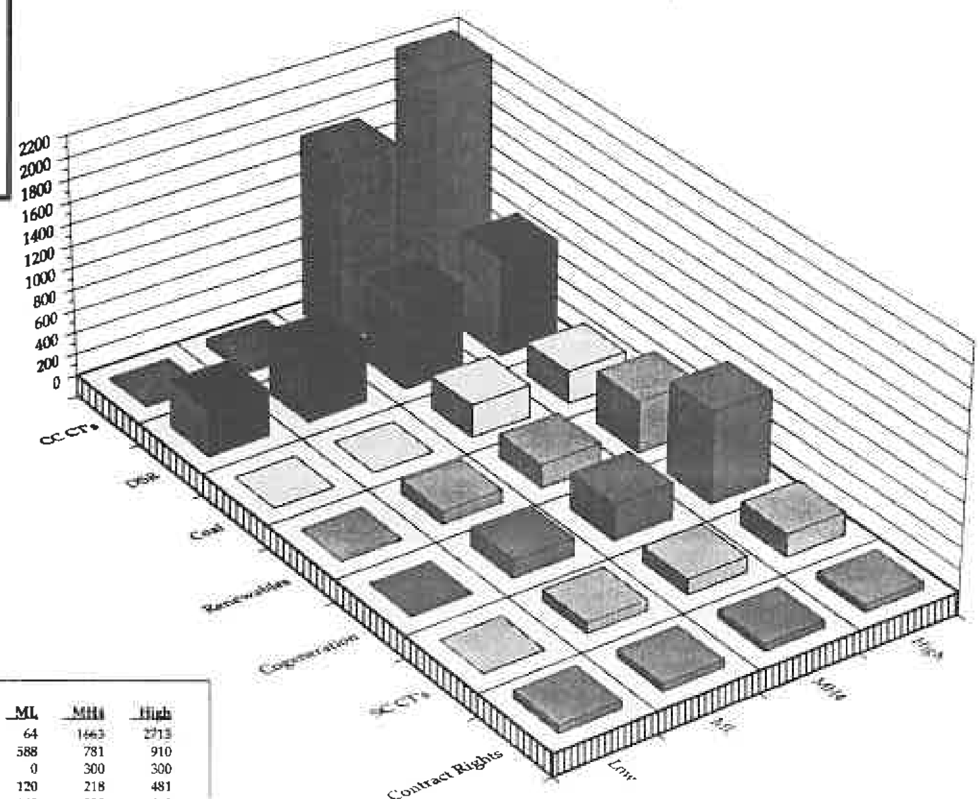
4 Forecasts Total Resource Additions in MWa 1992-2001



Average MW's

	Low	ML	MH4	High 2
CC CT's	0	0	350	875
DSR	122	287	418	485
Coal	0	0	0	300
Renewables	0	60	208	208
Cogeneration	0	0	330	500
SC CT's	0	0	142	130
Contract Rights	65	65	65	65
Total	**187**	**412**	**1513**	**2563**

4 Forecasts Total Resource Additions in MWa 1992-2011

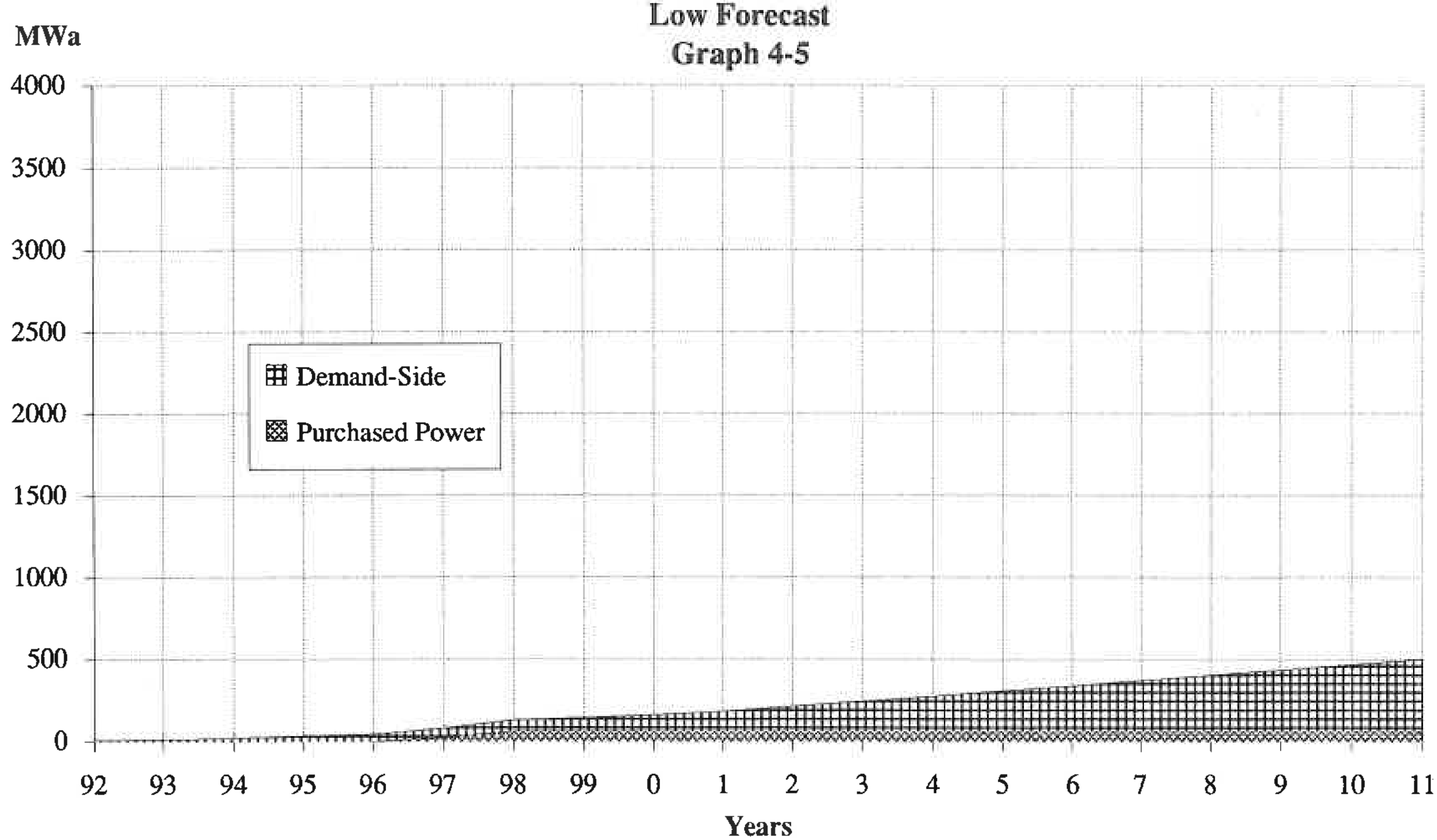


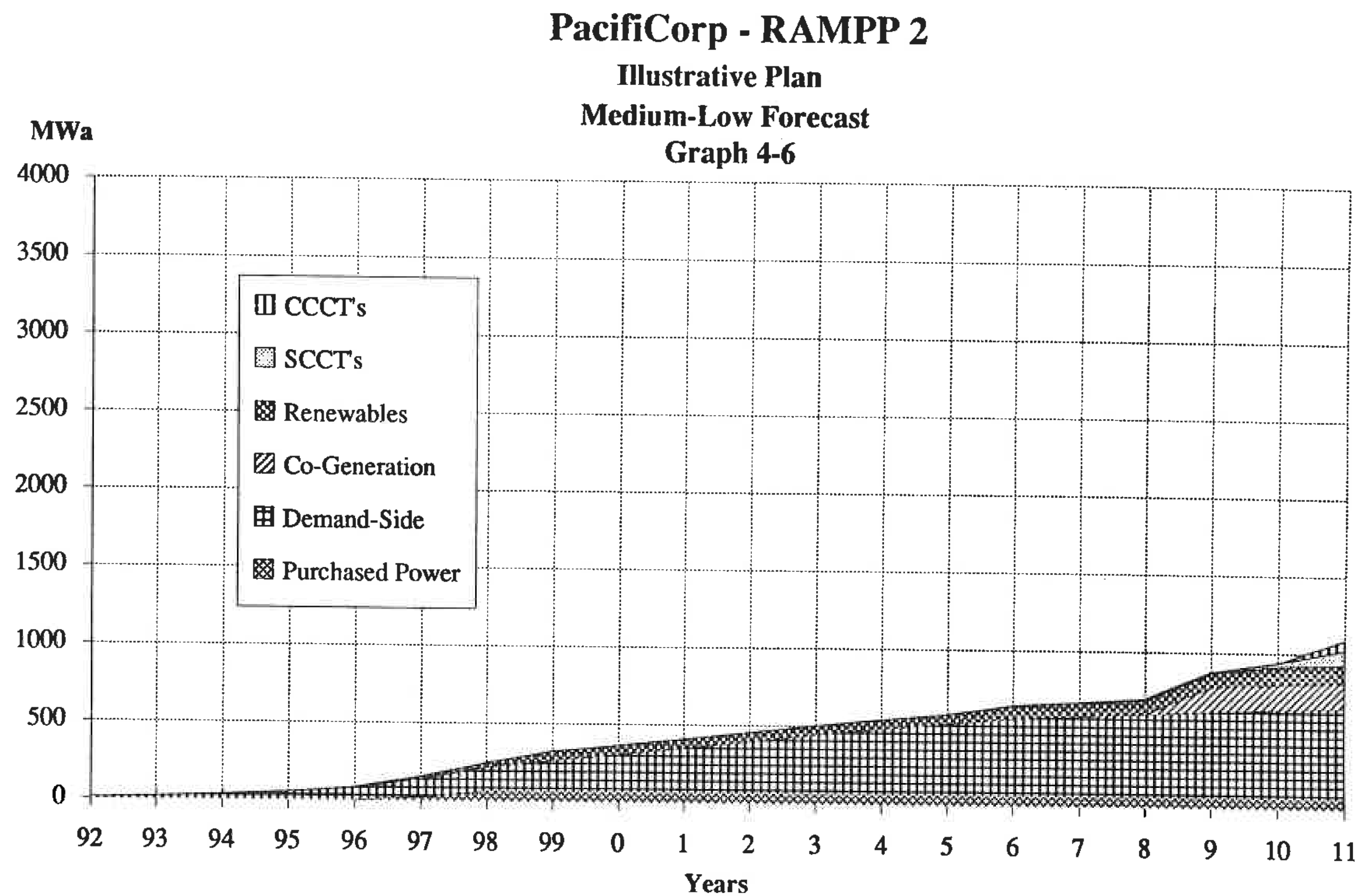
Average MW's

	Low	ML	MH4	High
CC CT's	0	64	1663	2713
DSR	435	588	781	910
Coal	0	0	300	300
Renewables	0	120	218	481
Cogeneration	0	160	330	840
SC CT's	0	95	142	208
Contract Rights	65	65	65	65
Total	500	1092	3499	5517

PacifiCorp - RAMPP 2

Illustrative Plan
Low Forecast
Graph 4-5




PacifiCorp - RAMPP 2
Illustrative Plan
Medium-Low Forecast
Graph 4-6
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

Medium Low Forecast

Graph 4-6 shows the resource additions under a ML forecast. Under ML, loads would increase at 1.7 percent per year, for a total addition of 1,912 MWa over the 20 years. Again, decreases in existing wholesale sales reduce the net resource needs. The needs can be met by 588 MWa of DSRs, the BPA Entitlement Agreement, 160 MWa of cogeneration, 120 MWa of renewables, 95 MWa of SCCTs, and 64 MWa from a CCCT in the last year of the plan. Prices would decrease on average by 0.75 percent per year. They decline by 12 percent in real terms between 1991 and 2000, and are then virtually flat. Emissions would increase only about half as much as GWh requirements.

Medium High Forecast

An illustrative plan for the MH load forecast was developed through a series of four steps. Under the MH forecast, loads would increase by a total of 4,030 MWa (at an average rate of 3.1 percent per year) over the 20 years. A table is provided in the Results Technical Appendix which shows the resource selections for each of the steps. The Results Appendix includes a full set of detailed information for each of the four steps. Step 1 was an untouched model run which selected resources without any policy intervention. The results of the untouched model run include 758 MWa of DSR acquisitions, the BPA Entitlement Agreement, cogeneration, wind, SCCTs, CCCTs, and two coal units.

Step 2 added in more renewable resources earlier than they were selected in the untouched run, consistent with the Company's environmental goal. The untouched run added 60 MWa of renewables for the entire planning period -- 30 MWa of wind in 1995, another 30 in 1998, and no additional renewables. Step 2 added renewables in increments beginning in 1996, so that by 2001, 148 MWa were in the plan, and by 2011, 218 MWa. DSR resources, the BPA Entitlement of 65 MWa and cogeneration of 330 MWa remained the same in both runs. The additional renewables in step 2 caused other resource selections to change from the selections in step 1. Step 2 added more SCCTs, 314 MWa instead of 263 MWa in step 1; it also added fewer CCCTs, 1313 MWa instead of 1528 MWa in step 1. The two coal plants, represented by Hunter 4 and Wyodak 2, are in both plans. The system cost in this second step is higher than in step 1, but emission levels are slightly lower.

Step 3 is the same as the environmental sensitivity case at level 1 of external costs (discussed below). The same amount of DSR, BPA Entitlement, cogeneration, and renewables are included as in step 2. Low levels of external costs were added to the internal costs of all resources, resulting in different resource choices. The model selected fewer SCCTs (168 MWa instead of 314 MWa in step 2), more CCCTs (1750 MWa instead of 1313 MWa in step 2), and only one coal plant (Wyodak 2). Both system cost and emissions are slightly less than in step 2.

Step 4 is the MH illustrative plan that is adopted for RAMPP-2. Its only difference from Step 3 is slightly less SCCTs (142 MWa rather than 168 MWa in step 3), slightly less CCCTs (1663 MWa rather than 1750 MWa in step 3), and Hunter 4 instead of Wyodak 2. Hunter 4 was substituted for Wyodak 2 because if the Company were to build a coal plant in the next 20 years, Hunter would the first choice, because of the more extensive existing transmission facilities at the Hunter site. The plan for the MH forecast includes 65 MWa from the BPA Entitlement, 758 MWa of DSR, 218 MWa of renewables, 330 MWa of cogeneration, 142 MWa of SCCTs, 1663 MWa of CCCTs, and the Hunter 4 coal plant at 300 MWa. This portfolio yields a lower system cost, a greater decline in real price growth, and lower emissions than any of the steps leading up to it. The adopted plan results in real price decreases of 9 percent between 1991 and 2001, with real escalation in the later years, leaving real prices about two percent lower at the end of the 20 years compared to the beginning.

Graph 4-7 shows the resource additions across the 20-year planning horizon for the MH forecast illustrative plan. This plan will be compared to several of the scenarios and sensitivities, since they are based on the MH forecast. For economy of description, the MH adopted plan will be referred to as **MH4.**

High Forecast

Under the high forecast, loads would grow at 4 percent per year, for a total addition of 5,910 MWa over the 20 years. Two steps were used to develop an illustrative plan for the high load forecast. The first and second steps both included the pilot renewable projects and 910 MWa of DSR acquisitions. The primary differences are that step 2 is limited to one coal plant instead of the two in step 1, and step 2 has more cogeneration, fewer renewables, slightly more SCCTs, and slightly fewer CCCTs than step 1. Graph 4-8 shows the resource additions across the 20-year planning horizon for the adopted plan for the high forecast. Prices would increase less in step 2 compared to step 1, and emissions would also be lower in step 2. The full information for steps 1 and 2 are in the Results Technical Appendix.

Although GWh requirements in the high plan grow at a higher rate (88 percent increase over 20 years) than in MH4 (58 percent), SO2, NOx, and TSP emissions all would grow at about the same rate as in MH4. CO2 emissions would grow at about 45 percent, compared to the MH4 rate of about 32 percent.

General Patterns

Out of the results for each of the forecasts, some general patterns for each resource category can be seen.

Demand Side Resources

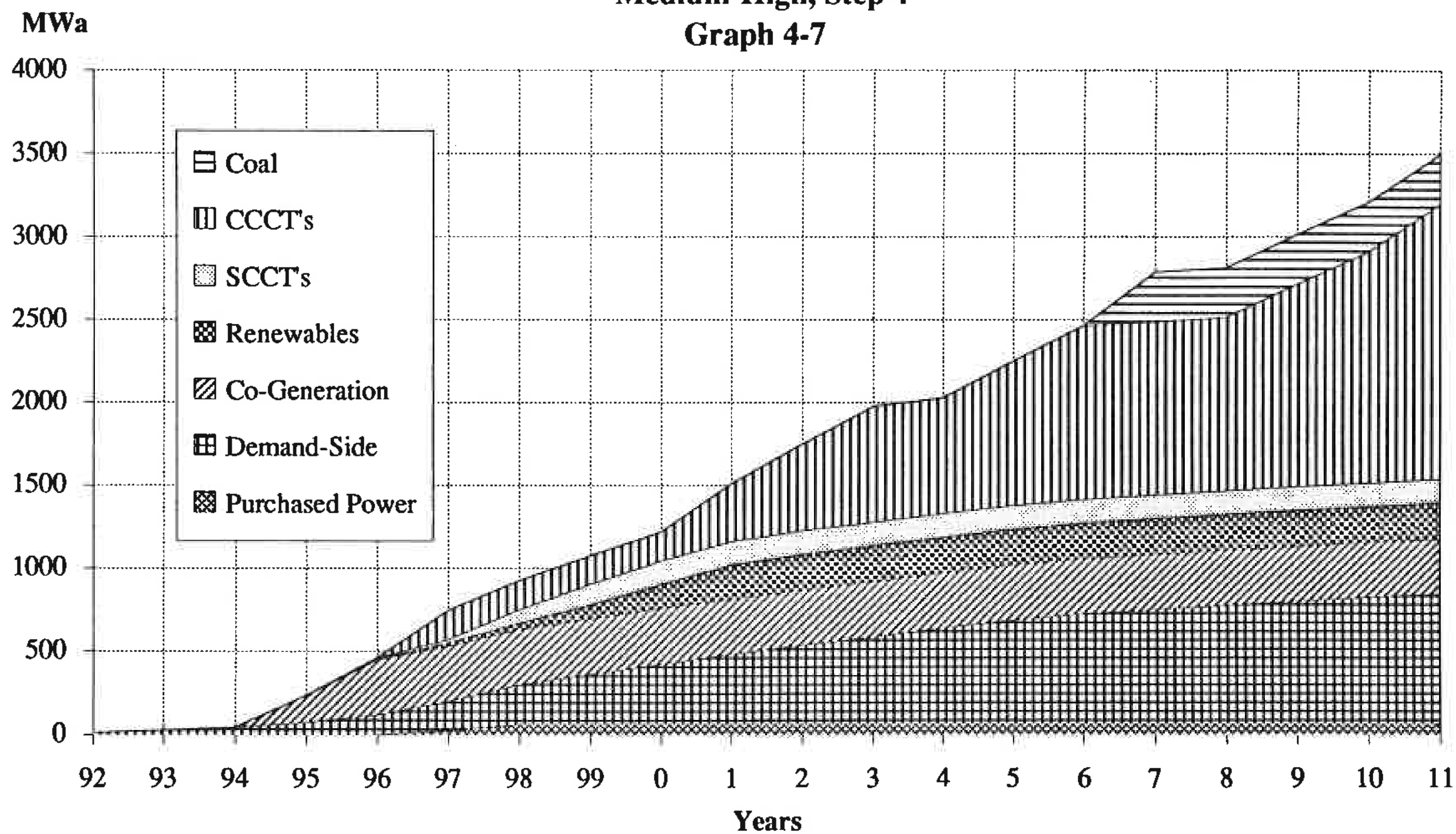
The real levelized cost of the DSRs is less than the real levelized cost of the supply side resources. Under current assumptions, DSR costs vary between 23 and 32 mills/kWh, whereas the supply side resource costs vary between 37 and 95 mills/kWh. Therefore, in all of the illustrative plans, the model adds DSRs first to fill the resource needs. The amount of DSRs available varies by forecast, because it is tied to economic assumptions about the number of new homes and businesses at each load forecast level. Table 3-5 identifies the amount of available DSRs for each forecast. In the ML case, 588 MWa are available, and 588 are included in the resource plan. In MH4, 781 MWa are available, and 781 are included in the resource plan. The same pattern shows up in the illustrative plans for the scenarios and sensitivities. If a sensitivity is based on the MH forecast case, the full amount of MH forecast level of DSRs will be included in the plan.

PacifiCorp - RAMPP 2

Illustrative Plan

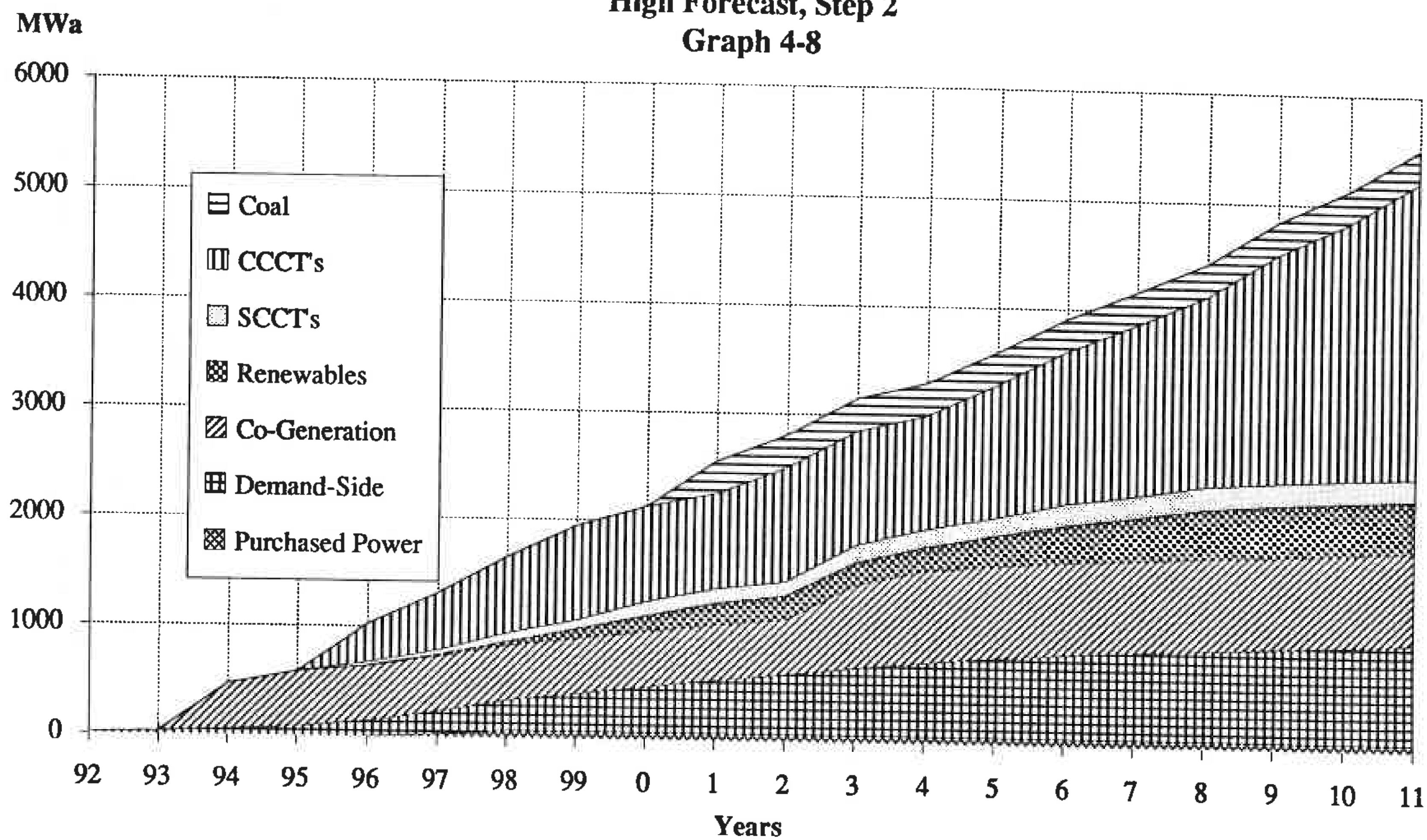
Medium-High, Step 4

Graph 4-7



PacifiCorp - RAMPP 2

Illustrative Plan
High Forecast, Step 2
Graph 4-8



If a higher cost effectiveness ceiling had been used, more resources would have been available. However, the Company did not believe that a higher cost effectiveness ceiling could be justified.

Renewable Resources

Because of the Company's new environmental goal, and to gain valuable experience with these technologies, the illustrative plans for all four forecasts add renewable resources to fill the resource needs sooner than they would be selected by the model. By 2001, the illustrative plans show 60 MWa of renewables in the ML case and 148 MWa in MH4. By 2011 those amounts increase to 120 and 218 MWa, respectively.

Peaking Resources

The model recognized a need for peaking resources, and added SCCTs; however, it sometimes added more than one small unit in one year. Under such conditions, the Company would build the most cost effective unit size as the need arose, not necessarily the small unit sizes. In all of the cases except the low and ML load growth, SCCTs are added by 1998, most often by 1996. The SCCTs are assumed to run at about a 20 percent capacity factor.

The amount of SCCTs added by the year 2001 are none for the low and ML forecasts, 712 MW for MH4, and 650 MW for the high. The amount added for the high is less than that needed for MH4 because the five CCCTs added in the high plan each provide 250 MW of peaking benefit. By 2011, the low forecast case still does not need any SCCTs, but 475 MW are included in the plan for the ML forecast, 712 MW for MH4, and 1,080 MWa for the high. Additional peaking resources will be an essential component of any future resource additions.

Cogeneration Resources

Cogeneration is relied on in all of the plans except the low load forecast, from 160 MWa in the ML, 330 MWa in MH4, and 840 MWa in the high forecast case by 2011. This resource is not added until 2009 in the ML case; in MH4 and in the high forecast it is included much earlier, in 1995 and 1994, respectively. Cogeneration is an essential early component of strategies to meet load growth.

Gas-Fired Resources

Cogeneration, SCCTs, and CCCTs represent a large portion of the illustrative plans. By 2011, the ML forecast calls for 184 MWa of gas-fired resources, MH4 calls for 1872 MWa, and the high includes 4031 MWa. The future price of gas will be critical in determining the actual timing and amount of gas-fired resources that are added to the system. Fortunately, in MH4 80 percent (measured by energy) of the new gas fired resources are added after 2000.

Coal Resources

PacifiCorp believes that newly constructed coal resources, under the proper conditions, remain a viable option. However, given the relatively high capital requirements of new construction, and the risk of such construction in light of global warming uncertainties, new coal additions were limited to no more than one unit in the adopted illustrative plans for the four forecasts. New coal additions did not occur until 2007 in MH4 and in 2001 in the high forecast plan.

Additional energy and capacity from existing coal resources may be available to PacifiCorp at significantly lower capital costs and without the construction risks of new coal resources. The CO2 emission impacts of existing coal resource acquisitions are also different from newly constructed coal, since such resources would be operated regardless of ownership. Therefore, potential acquisitions of existing coal resources will be carefully examined as a substitute for new gas-fired generation and as a means of balancing the large uncertainties of future gas price increases.

As indicated in the Q&A chapter, the Company has limited windows of opportunity available to acquire existing thermal resources. Such resources will be evaluated with consistent life cycle cost criteria.

The implications of future natural gas prices, potential CO2 limits and strategies, and the development of advanced coal conversion technologies will all influence future coal resource construction decisions. PacifiCorp will continue to monitor these issues as part of its ongoing strategic and integrated resource planning activities.

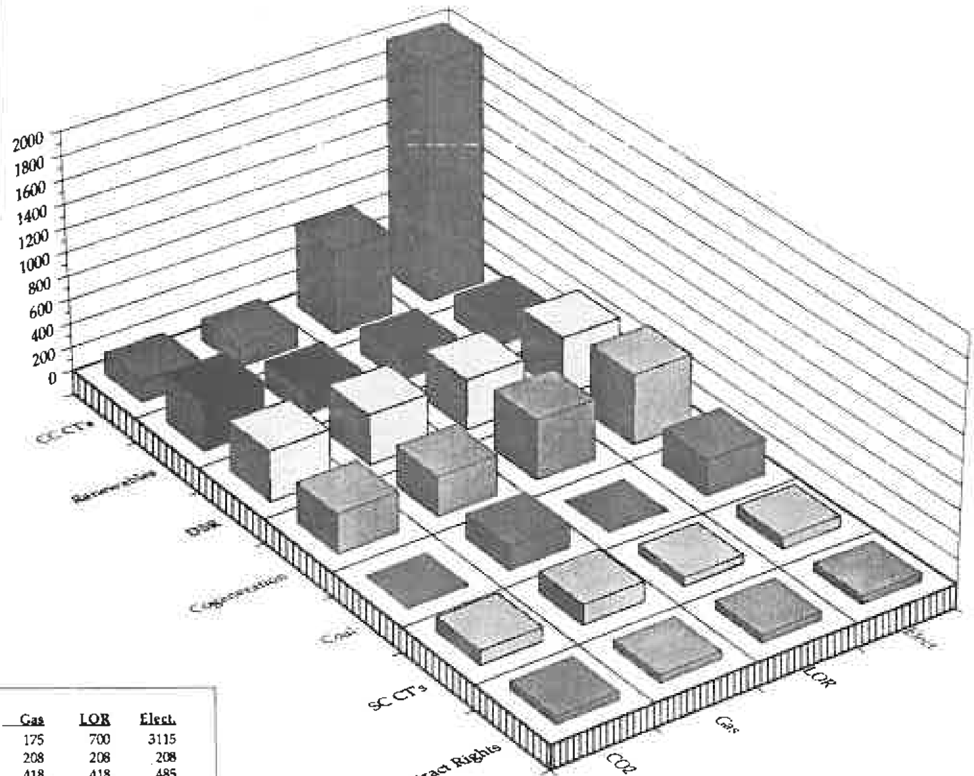
FOUR SCENARIOS: ILLUSTRATIVE PLANS

Graph 4-9 shows the resource additions at 2001 and 2011 for each of the scenarios: electrification (which, with 5 percent load growth, results in needs higher than those in the high forecast) and the other three scenarios -- loss of resources, high gas prices, and CO2 tax (which reflect the MH forecast). Changes in the cost or availability of resources result in different selections of resources to meet the resource needs of the MH forecast. The four scenarios are identified on the graph as "Elect." for Electrification, "LOR" for loss of resources, "Gas" for high gas prices, and "CO2" for CO2 tax.

Electrification Scenario

Graph 4-10 shows the resource additions across the 20 years to meet load growth needs under the electrification scenario. The portfolio of new resources for this scenario is similar to that for the high forecast. Both include the BPA Entitlement Agreement, 910 MWa of DSR, and 218 MWa of renewables. The variations are that, for the electrification scenario, the model adds less cogeneration, slightly fewer SCCTs, a great deal more CCCTs (7709 MWa compared to 2975 MWa in the high forecast plan), and two coal plants instead of the one in the high forecast plan. Real retail prices would increase at a higher rate under this future than under any of the others, at 0.72 percent annually. Total GWh requirements would grow by 127 percent, while CO2 emissions would increase by half that, and SO2 emissions would increase by only 13 percent.

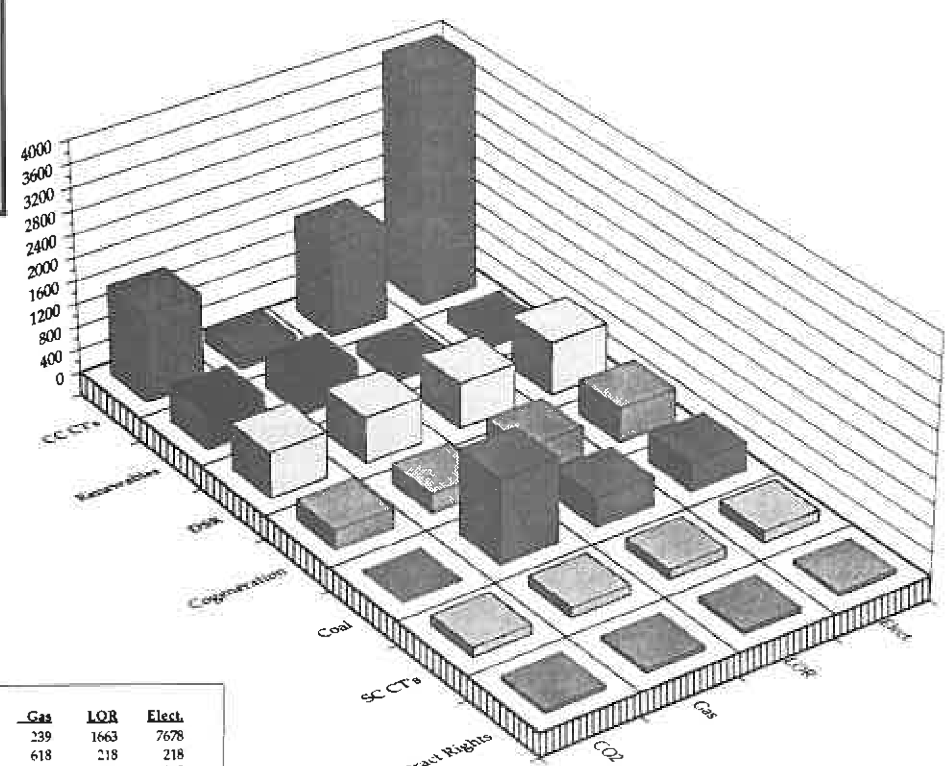
4 Scenarios Resource Additions in MWa 1992-2001



Average MW's

	CO2	Gas	LOR	Elect.
CC CT's	175	175	700	3115
Renewables	408	208	208	208
DSR	418	418	418	485
Cogeneration	330	330	500	585
Coal	0	192	0	300
SC CT's	118	166	75	94
Contract Rights	65	65	65	65
Total	1514	1554	1966	4852

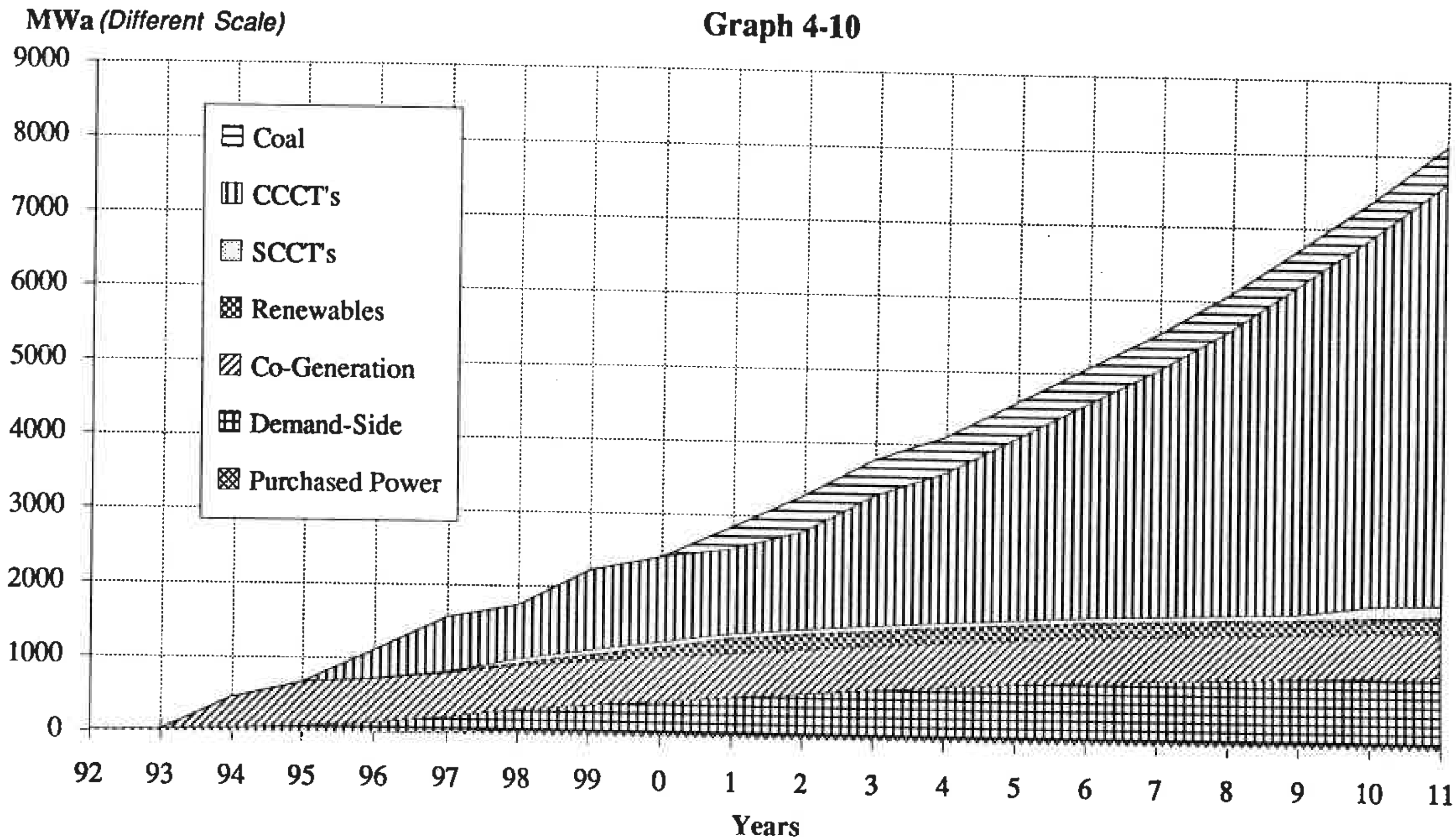
4 Scenarios Resource Additions in MWa 1992-2011



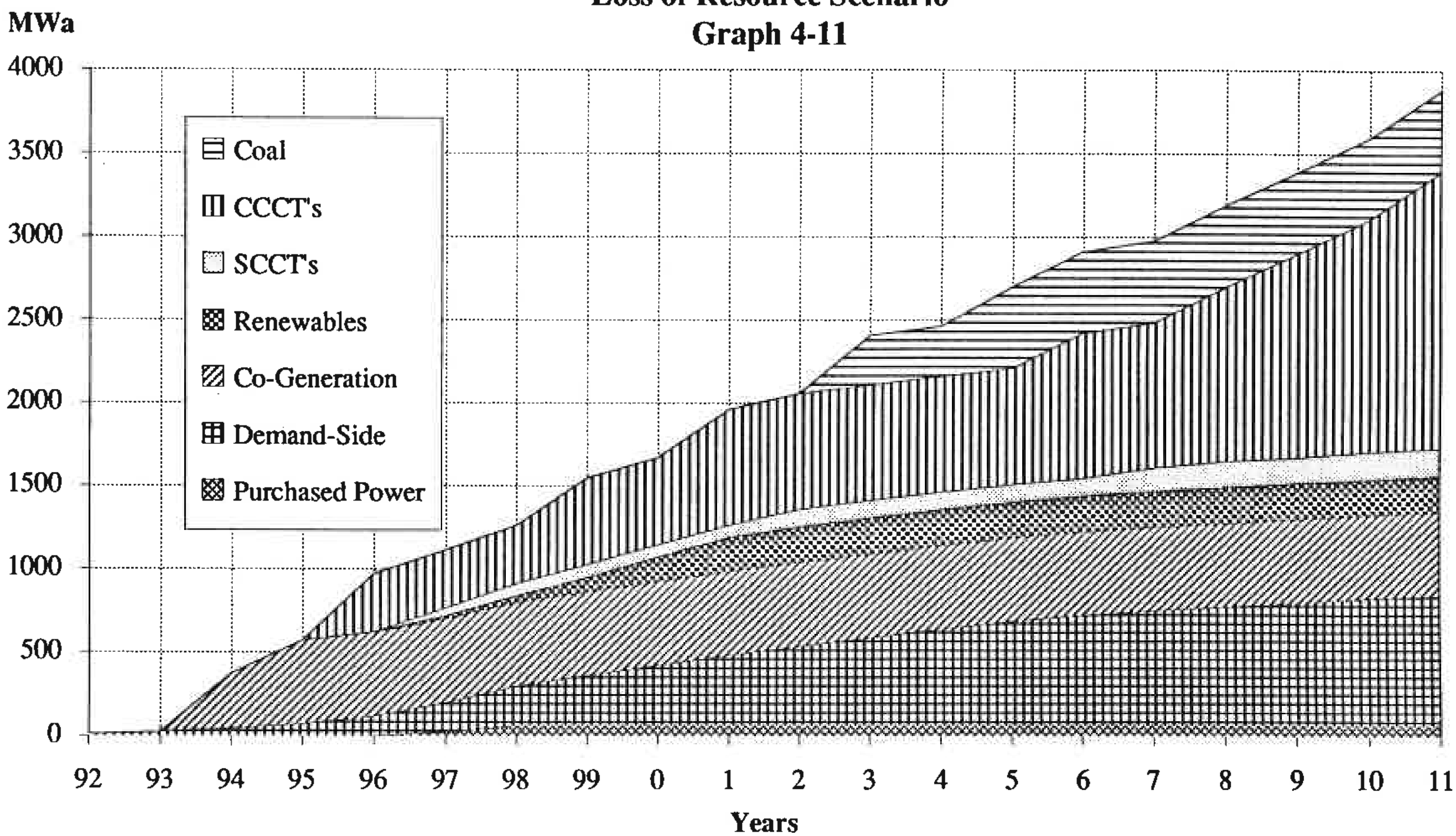
Average MW's

	CO2	Gas	LOR	Elect.
CC CT's	1552	239	1663	7678
Renewables	618	618	218	218
DSR	781	781	781	910
Cogeneration	330	330	500	585
Coal	0	1430	492	492
SC CT's	157	166	166	188
Contract Rights	65	65	65	65
Total	3503	3629	3885	10136

PacifiCorp - RAMPP 2
Illustrative Plan
Electrification Scenario
Graph 4-10

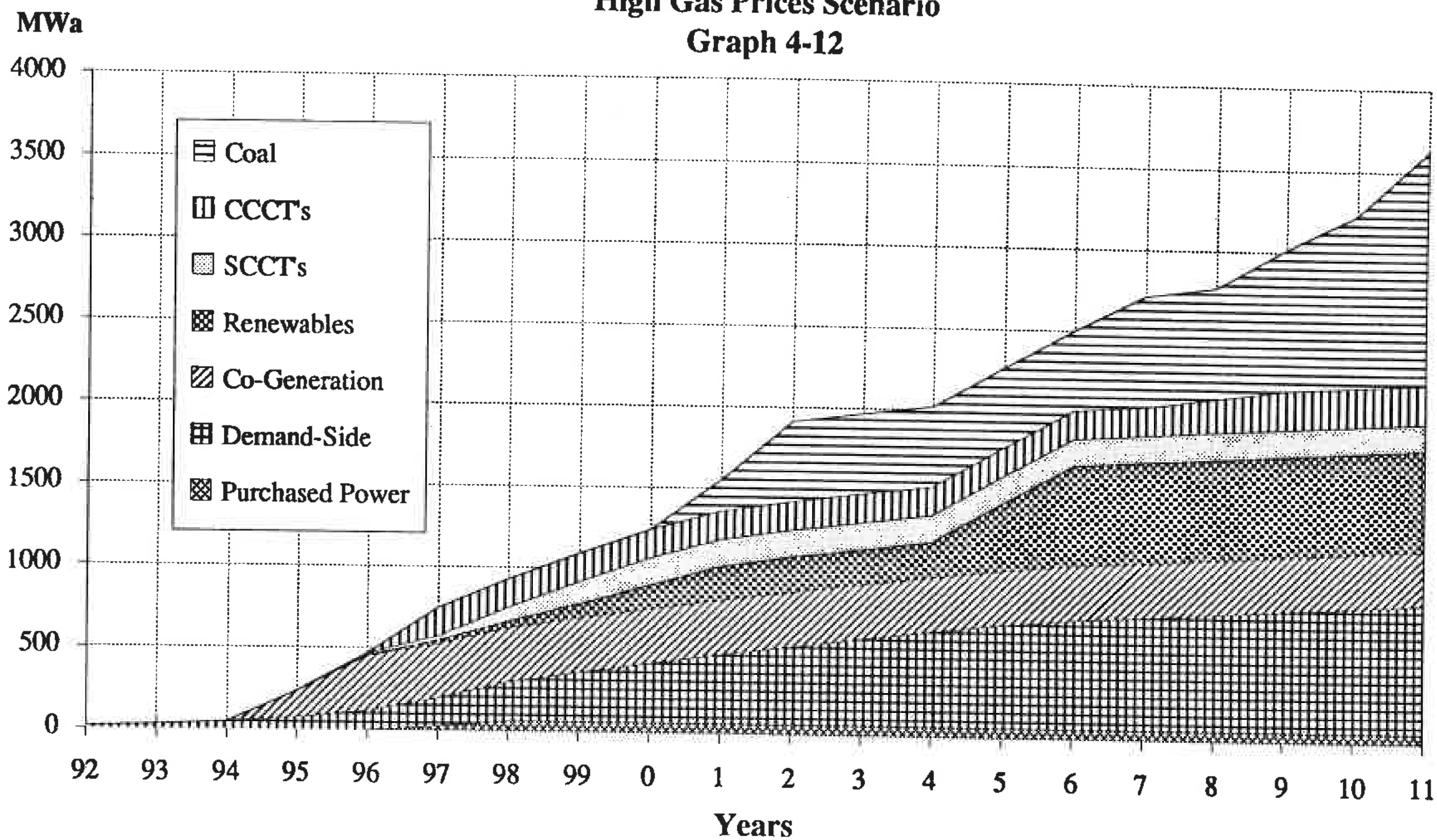


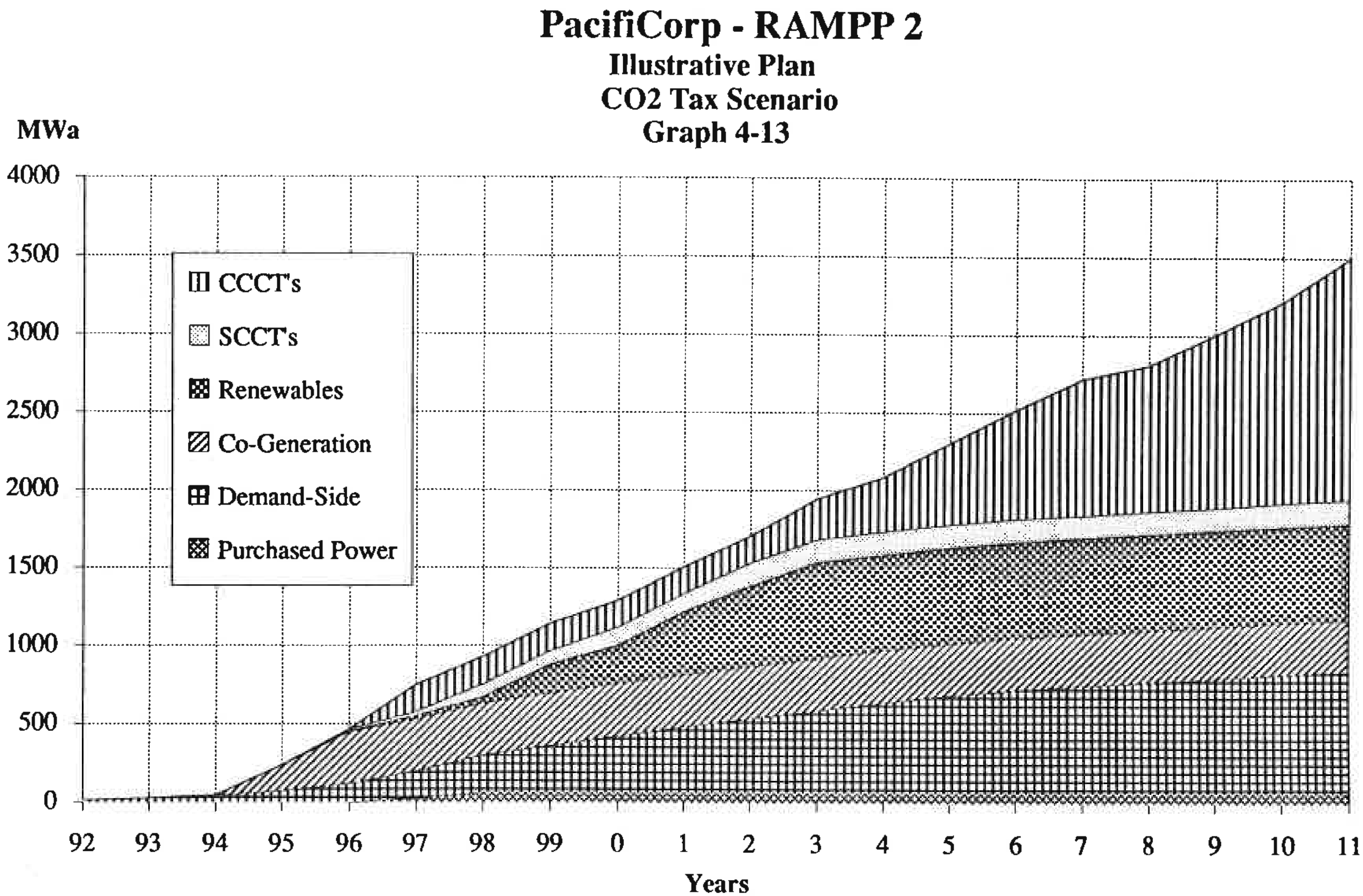
PacifiCorp - RAMPP 2
Illustrative Plan
Loss of Resource Scenario
Graph 4-11



PacifiCorp - RAMPP 2

Illustrative Plan
High Gas Prices Scenario
Graph 4-12




PacifiCorp - RAMPP 2
Illustrative Plan
CO2 Tax Scenario
Graph 4-13
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

Loss of Resources Scenario

The loss of resources scenario consists of two parts: 1) loss of the ramp-up of the BPA capacity contract (a contract which provides 1100-1400 MW of peak capacity); and 2) loss of hydro energy shaping ability.

Graph 4-11 shows the resource additions under this scenario. The illustrative plan is a slight variation on MH4. The loss of resources scenario includes more cogeneration, slightly more SCCTs, and a second coal plant. The 20-year system cost would be about two percent or $600 million higher than in MH4. Real retail prices would decrease by 0.05 percent in the loss of resources plan, and would decrease by 0.13 percent in MH4. If the regional solution to help various fish species results in the impacts considered in this scenario, customers would see a small price impact. Emissions would also be higher under the loss of resources scenario, compared to MH4. This is a case where efforts to help one aspect of the environment could lead to other adverse environmental consequences.

High Gas Price Scenario

Graph 4-12 shows the resource additions if gas prices are assumed to be significantly higher than in the other cases. Under the base assumption, gas prices begin at $1.65/mmbtu, escalate through the year 2011 at 9.94 percent nominal, and after 2011 at inflation (zero percent real growth). The high gas price scenario begins gas prices at a higher level -- $1.95/mmbtu, escalating through 2011 at 9.94 percent nominal, and escalating after 2011 at 8.63 percent nominal.

Compared to MH4, the illustrative plan for the high gas scenario adds the same amount of BPA Entitlement, DSR, and cogeneration. However, its major effect is to reduce the amount of now expensive gas fired resources and substitute lower cost alternatives -- renewables and coal. This plan adds more renewables (618 MWa compared to 218 in MH4), slightly more SCCTs, very few CCCTs (only 239 MWa compared to 1663 in MH4), and a great deal more coal (1430 MWa compared to 300 in MH4). The 20-year system cost would increase by about two percent or $600 million in the high gas prices case compared to MH4. Real retail prices would grow at 0.17 percent, rather than decrease by 0.13 percent in MH4. If gas prices were to increase as projected in the high gas price scenario, customers would see an impact on prices. Emissions would also be higher with high gas prices. For example, CO_2 emissions would grow at 41 percent rather than only 32 percent as in MH4. The other three categories of emissions would also grow at faster rates than in MH4.

CO2 Tax Scenario

The CO_2 tax scenario assumes a $30/ton CO_2 tax. Graph 4-13 shows the resulting selection of resources, assuming such a tax is added to the cost of each of the appropriate resources in the portfolio. The resulting illustrative plan includes more renewables (618 MWa rather than 218 in MH4), slightly more SCCTs, slightly less CCCTs, and no coal plants. The 20-year system cost would increase by about $6.1 billion over system costs in MH4. Only about $400 million of that would be due to differences in resource choices; the remainder (about 95 percent) would be from the tax itself. Real retail prices would grow at 2.3 percent instead of declining as in MH4 by 0.13 percent. Emissions would be slightly reduced compared to MH4. CO2 would grow at about 27 percent instead of 32 percent, for example, and the other emissions would be favorably affected, although not dramatically. Customers would be paying a very high price for a modest decrease in CO2 emissions.

ENVIRONMENTAL COSTS: ILLUSTRATIVE PLANS

Four different levels of externality adders were used to examine the impact of environmental externalities on resource planning. The column titles on table 4-14 show the four levels. The first one has low non-CO2 costs and $5/ton for CO2. The other three all have high non-CO2 costs and different levels of CO2 costs, from $0, to $10, and finally to $30/ton. These external cost adders were used in two ways.

First, Table 4-14 shows all new resources, ranked first according to internal costs and then ranked again based on total costs after each of the four levels of externality adders have been applied. In the first column (by internal cost only), the least costly is listed and ranked first, and the most costly is listed and ranked last. The ranking is affected little by the external cost adders at level 1 or 2. Level 3 external cost adders moves CCCT, wind and geothermal up, and the coal technologies move down. Adding level 4 external cost adders moves the coal technologies further down, and the renewables higher in the rankings.

The Company then used these four external cost adders to develop four different resource plans. Each external cost adder was added to the internal costs of new resources, and an illustrative resource plan was developed assuming all resources had their original internal costs, plus the additional external costs. A fifth plan was also developed to test the impact of two events together: level three external costs and high gas prices. All five plans assumed a MH forecast for resource needs. Graph 4-15 shows the resource additions by the year 2001 and by 2011 for the five plans.

Plans using any of the four external cost adders included the BPA Entitlement power, 781 MWa of DSR, and 330 MWa of cogeneration. The variations came in the amounts of renewables, SCCTs, CCCTs, and coal. The following table shows the amounts of MWa of each resource category which were added in each plan:

	Renewables	SCCTs	CCCTs	Coal
MH4	218	142	1663	300
Level 1 (E1)	218	168	1750	192
Level 2 (E2)	218	126	1989	--
Level 3 (E3)	418	110	1814	--
Level 3, high gas	670	282	350	1055
Level 4 (E4)	618	200	1528	--

The E1 plan is very similar to MH4, since it is the same plan used in step 3 leading to MH4. The E2 plan differed from MH4 only in that E2 resulted in slightly fewer SCCTs, more CCCTs, and no coal plants. The E3 plan had more renewables, fewer SCCTs, more CCCTs, and no coal plants. External costs at level 3 with high gas prices produced a plan that had even higher renewables, more SCCTs, very few CCCTs, and a great deal more coal. The E4 plan was similar to the plan of level 3 with high gas, except the coal from the level 3 with high gas plan was replaced by CCCTs in the E4 plan.

PacifiCorp - RAMPP 2

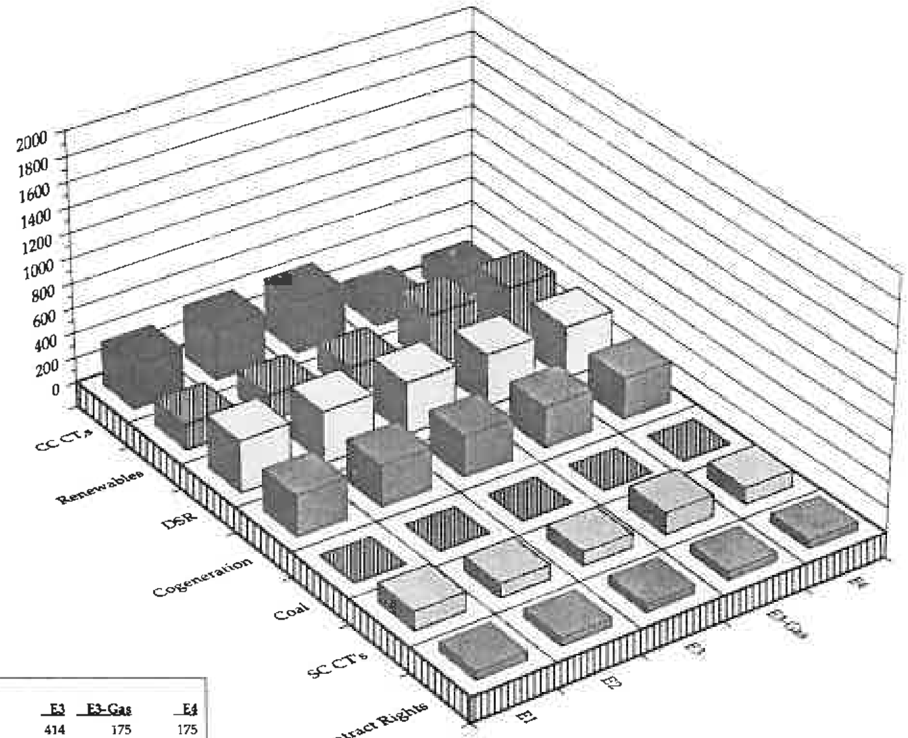
New Technologies' Costs Without & With External Cost Adders

Mills/kWh for 2001 In-Service Date

Table 4-14

		Internal Costs		Sensitivity-Level 1		Sensitivity-Level 2		Sensitivity-Level 3		Sensitivity-Level 4	
SO2 $/ton		$0		$1000		$2000		$2000		$2000	
NOx $/ton		$0		$100		$4000		$4000		$4000	
TSP $/ton		$0		$200		$3000		$3000		$3000	
CO2 $/ton		$0		$5		$0		$10		$30	
	CF	[1]	Rank	[2]	Rank	[3]	Rank	[4]	Rank	[5]	Rank
Hunter 4	80%	36.00	1	42.31	2	47.25	3	58.00	5	79.50	5
Wyodak 2	80%	37.87	2	44.48	3	49.59	4	61.41	6	85.06	7
Cogen (Gas)	50%	39.27	3	40.74	1	41.03	1	43.96	1	49.81	1
CCCT (Large)	80%	44.17	4	46.40	4	45.08	2	49.52	2	58.41	4
AFB Coal	80%	51.12	5	57.11	7	55.23	6	65.98	8	87.48	8
IGCC Coal	80%	51.54	6	56.64	6	52.96	5	62.85	7	82.63	6
Wind	26%	55.88	7	55.88	5	55.88	7	55.88	3	55.88	2
Geothermal	90%	57.67	8	57.67	8	57.67	8	57.67	4	57.67	3
SCCT (Medium)	20%	75.96	9	79.18	9	77.27	9	83.71	9	96.58	9
Luz Solar	40%	105.81	10	106.54	10	106.69	10	108.15	10	111.08	10

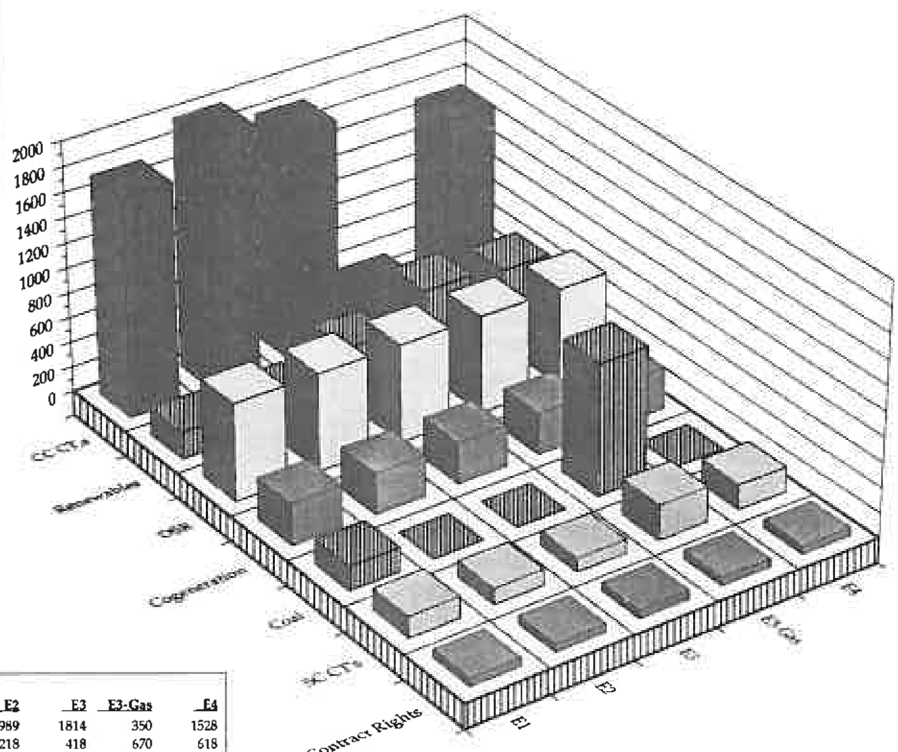
Environmental Sensitivities Resource Additions in MWa 1992-2001



Average MW's

	E1	E2	E3	E3-Gas	E4
CC CT,s	350	414	414	175	175
Renewables	208	208	208	408	408
DSR	418	418	418	418	418
Cogeneration	330	330	330	330	330
Coal	0	0	0	0	0
SC CT's	150	110	110	175	130
Contract Rights	65	65	65	65	65
Total	**1521**	**1545**	**1545**	**1571**	**1526**

Environmental Sensitivities Resource Additions in MWa 1992-2011



Average MW's

	E1	E2	E3	E3-Gas	E4
CC CT,s	1750	1989	1814	350	1528
Renewables	218	218	418	670	618
DSR	781	781	781	781	781
Cogeneration	330	330	330	330	330
Coal	192	0	0	1055	0
SC CT's	168	126	110	282	200
Contract Rights	65	65	65	65	65
Total	**3504**	**3509**	**3518**	**3533**	**3522**

The CO_2 tax scenario provides additional information regarding the impact of external costs on resource planning. The table below compares the system cost for MH4 to the resource plans under the different external cost adder levels.

	20-year NPV of Operating Revenue (System Cost) (in millions of dollars)
MH4	$31,319
E1	$31,332
E2	$31,306
E3	$31,310
Level 3, high gas	$32,098
E4	$32,732
CO2 $30/ton Tax without the tax	$31,731

With CO_2 external costs at $10/ton or less (levels 1, 2, and 3) the system cost would not be significantly affected. The plan developed using CO_2 external costs of $30/ton ($CO_2$ tax scenario without accounting for the tax itself) raised system costs by about $400 million. When the CO_2 external cost of $30/ton is combined with high gas prices, the system costs increase by about $800 million. When the CO_2 external cost of $30/ton is combined with high external cost for other emissions, the system costs increase by about $1.4 billion. A CO_2 external cost of $30/ton is large enough to significantly affect resource choices.

Significant emission reductions from MH4 occur with level 3 external costs and low gas prices, or E4. E3 brings reduced emissions except for SO_2. E4 results in emission reductions for all four categories, but at a significant cost to the system.

Emissions

Table 4-3 shows the change in emission levels for each resource plan. It illustrates the difficulty in reducing emissions when a large existing system is involved. CO_2 emissions increase in all of the cases, but consistently less than GWh requirements increase. Typically, the percentage increase in CO_2 emissions is about half the percentage increase in GWh requirements. However, in two cases, this pattern does not hold: the low forecast plan and the high gas prices scenario plan do not result in a reduced growth rate for CO_2 emissions. In two other cases, the increase in CO_2 emissions is smaller than the other cases: E4 and the new renewables only plan.

SO_2 emissions also increase in all the plans, but their percentage increase is consistently less than that for CO_2, tending to be closer to a quarter of the percentage increase in GWh requirements. The most notable case which has a much lower increase in SO_2 is the electrification scenario. None of the cases result in significantly greater SO_2 emissions.

NO_x emissions decrease in all the cases, but the pattern relative to GWh requirement is less consistent. TSP emissions increase in all cases, with a pattern similar to that of CO_2.

Minimizing System Costs and Emissions

An additional form of analysis was performed to illustrate the benefits of a methodology which does not require external cost adders at the beginning of the planning process. This method allows an examination of the trade-offs between increased environmental benefits and system cost. To show the total system costs relative to the level of emissions, all of the cases that were based on the MH growth rate have been plotted. Four plots are provided as tables 4-16, 4-17, 4-18, and 4-19. They are, respectively, for SO2, NOx, TSP, and CO2 emissions. These 17 cases are designated on the plots as follows:

CO2	CO2 tax scenario
D-	DSR -30% sensitivity
D+	DSR +30% sensitivity
E1	Environmental sensitivity at level 1 external costs
E2	Environmental sensitivity at level 2 external costs
E3	Environmental sensitivity at level 3 external costs
E3G	Environmental sensitivity at level 3 external costs with high gas prices
E4	Environmental sensitivity at level 4 external costs
G	High gas price scenario
LOR	Loss of resources scenario
MH1	MH step 1
MH2	MH step 2
MH3	MH step 3 (same as E1)
MH4	MH step 4
R	Renewables only sensitivity
R20	Renewables cost 20% less sensitivity

The emissions are total system emission levels for the year 2011. This provides one perspective on future emissions, but does not compare cumulative emissions over the 20-year planning horizon, which is another valid measure of environmental impacts. Each dot on a plot represents the resource plan for one sensitivity. The lower the dot is on the plot, the lower the system costs are for that resource plan. The further to the left the dot is on the plot, the lower the emissions are for that resource plan in the year 2011. The cases which fall in the lower left corner of the graph are the cases which have both low system costs, and low emissions. They can be considered the "best" cases. The closer a case is to the origin of both axes, the more desirable it is. It is worth noting that in all of the graphs, the variation in emission levels is not large; thus at issue are small gains in emission levels.

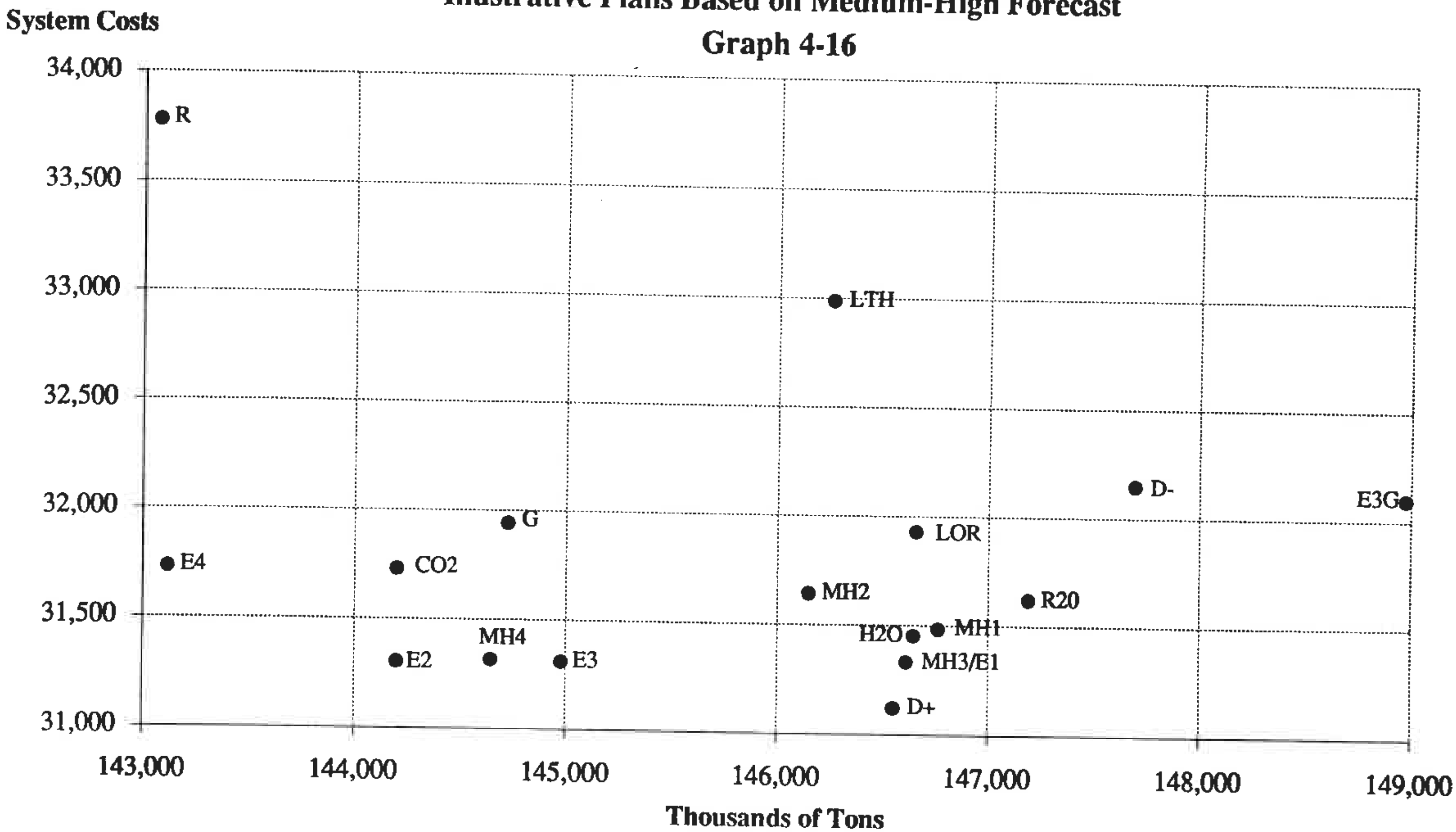
The five "best" cases for each emission are identified below, with an x under the column where it is one of the best five cases for that emission. Each emission will have five cases designated as the five best for that emission. The five "best" cases are those which are closest to the bottom left hand corner of the graph -- the ones which result in both minimizing system costs and minimizing emission levels.

PacifiCorp - RAMPP 2

System Costs vs. SO2 Emissions in 2011

Illustrative Plans Based on Medium-High Forecast

Graph 4-16



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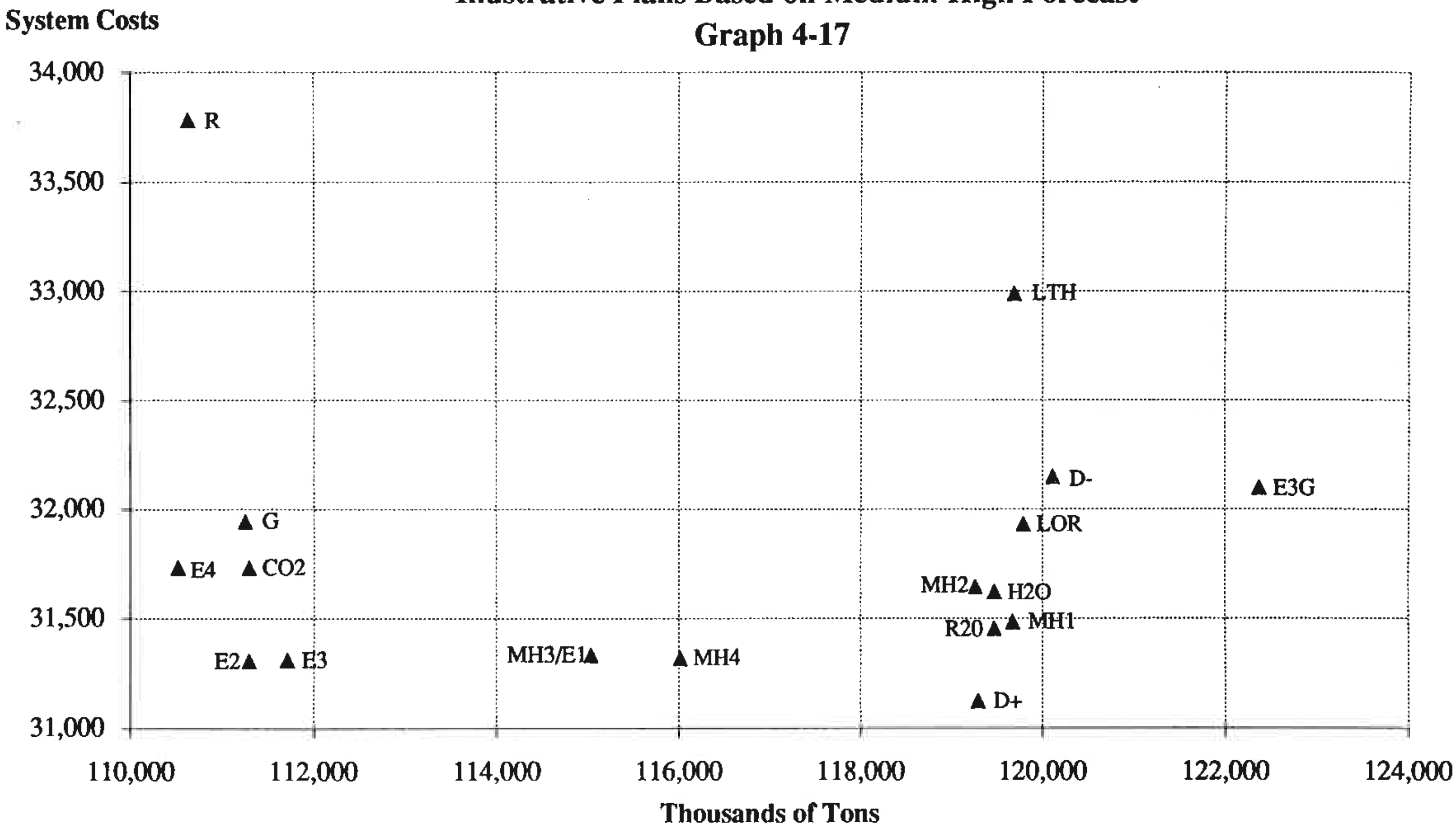
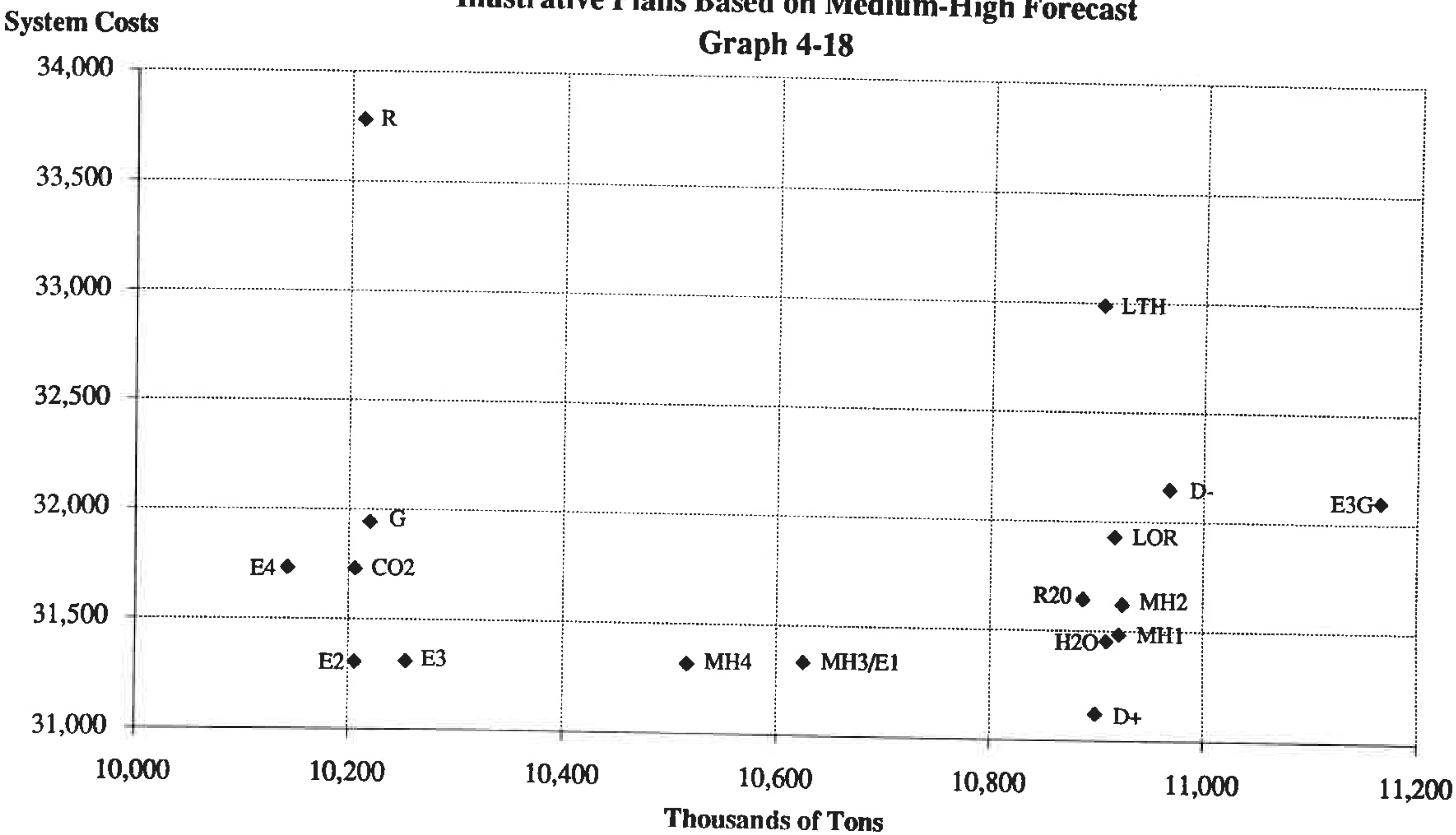
System Costs vs. NOx Emissions in 2011
Illustrative Plans Based on Medium-High Forecast
Graph 4-17

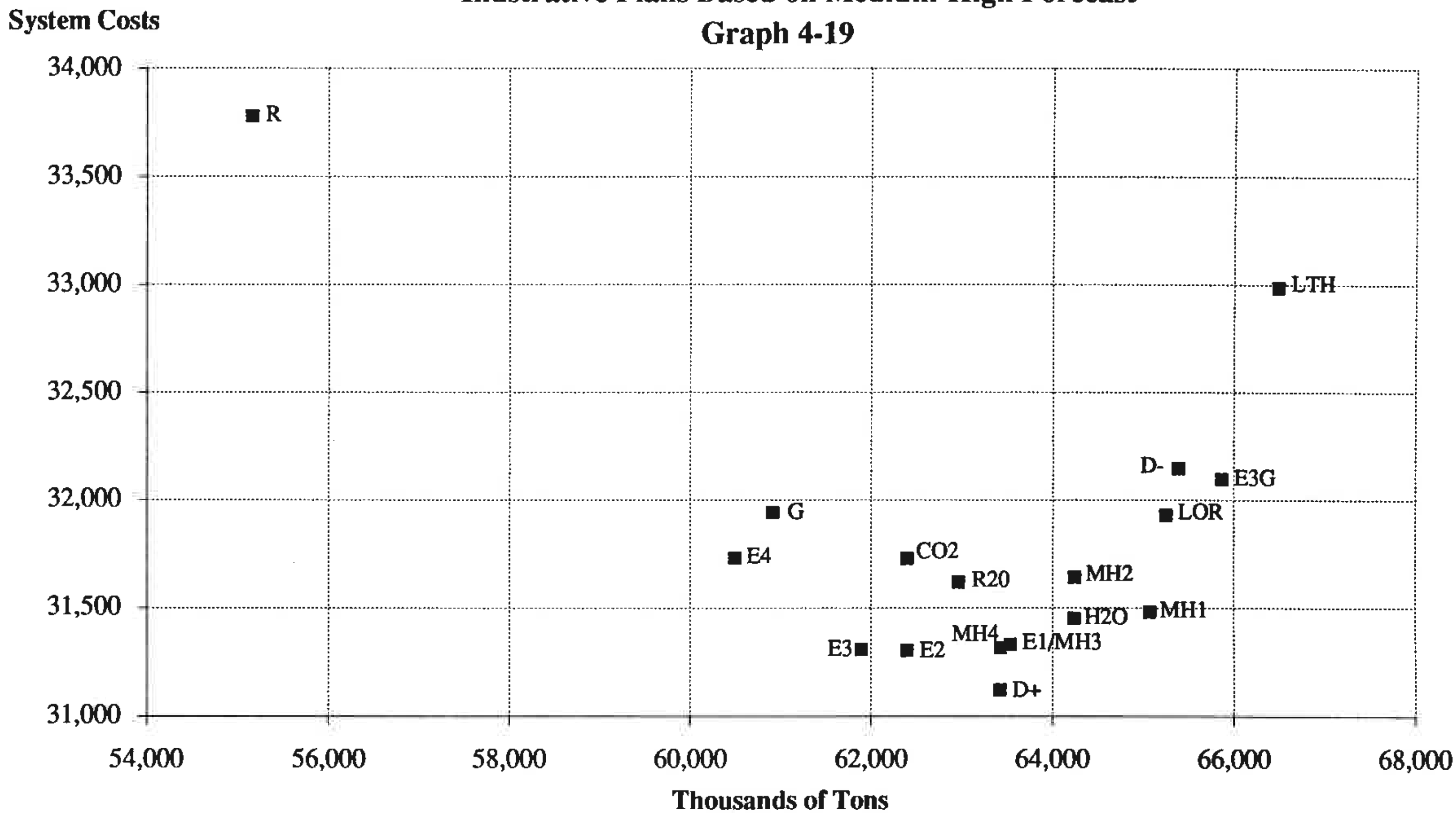


PacifiCorp - RAMPP 2
System Costs vs. TSP Emissions in 2011
Illustrative Plans Based on Medium-High Forecast
Graph 4-18



PacifiCorp - RAMPP 2

System Costs vs. CO2 Emissions in 2011
Illustrative Plans Based on Medium-High Forecast
Graph 4-19



	SO2	NOx	TSP	CO2
MH4	x			
E2	x	x	x	x
E3	x	x	x	x
E4	x	x	x	x
CO2	x	x	x	
G		x	x	x
D+				x

Although the five "best" cases included three which are based on specific external cost adders, the same form of analysis can be done using multiple resource plans based on cases using any variables or strategies to create multiple sensitivities. Those multiple sensitivities would then be plotted to find the ones which minimize both system costs and emissions.

The plans which based resource choices on internal plus external costs at levels 2, 3, and 4 are in the "best" case group for all four emissions, with E2 and E3 having lower system costs than E4. How do their resource choices differ from MH4, the plan for the MH forecast that was adopted for RAMPP-2? We can look at the total MWa added in certain resource categories at the end of the planning period. The amount of BPA purchase, DSR, and cogeneration are the same for all four cases. SCCTs are added based on peaking needs, rather than on contribution to emission levels. The relevant resource categories and the MWa added are shown below:

	Renewables	CCCTs	Coal
MH4	218	1663	300
E2	218	1959	--
E3	418	1814	--
E4	618	1528	--

E2 has almost the same system cost as MH4, yet achieves a lower SO2, NOx, TSP, and CO2 emissions level. E3 also has almost the same system cost as MH4, but achieves a lower emissions level for all but SO2. E4 has a higher system cost, almost $1 million, compared to MH4. Therefore, the trade-off to E4 may not be warranted. However, in the long run, these results indicate that the Company should carefully consider building a new coal plant, and if renewables prove to be cost effective, add more renewables than envisioned in MH4. Through the remainder of this century, MH4, E2 and E3 all had the same level of renewables, and no new coal. Thus for these next ten years, the resource choices for MH4 are very similar to those for E2 and E3. The actions the Company is planning in the near future are appropriate for minimizing both system costs and emissions.

Impact of External Costs on Dispatch

Environmental dispatch -- the dispatch of a utility's resources based on their internal costs plus an external cost adder -- is an issue under discussion by some regulatory bodies. Normally, resources are dispatched based on their internal costs and load-following requirements. PacifiCorp believes that its resource planning should and can consider the environmental impacts of resource decisions. The Company also believes that existing resources that comply with all applicable environmental requirements should be operated to minimize direct system costs. However, the Oregon order which acknowledged the Company's RAMPP-1 planning report stated: "In the next plan, PacifiCorp should also analyze the external costs of existing resources and determine whether including external factors would affect the dispatch of those resources." (Order 90-1658, p. 6) Table 4-20 and the following discussion are provided in response to that request.

Current information about how others would dispatch or how wholesale markets would address environmental dispatch is insufficient to provide a complete analysis of the impact of using external cost adders in making dispatch decisions. Among the states PacifiCorp serves, there is no consensus regarding whether environmental dispatch should be done, or what the external cost adders should be. The Company is concerned about increased operating costs and increased risk of inadequate compensation for those increased operating costs. If one state decides to adopt requirements to incorporate externality costs in operating decisions for the utilities providing service in that state, and those requirements increase utility costs, that state will need to address the issue of cost allocation.

Table 4-20 (two pages) shows the ranking of the Company's existing thermal resources by internal variable cost, and by each of the four external cost adder levels.

Column 1 shows the internal costs, and the internal cost ranking of the existing resources. The resource with the highest rank would be dispatched last. Column 2 shows total costs after level 1 of external costs have been added to the internal costs and the new ranking of resources according to those costs. Level one moves Colstrip, Hunter, Huntington, Bridger, Craig, and Gadsby up in the rankings (to earlier dispatch). Johnston, Wyodak, Hayden, Carbon, and Centralia move down in the rankings (for later dispatch).

Column 3 shows total costs after the second level of external costs have been added, and the new ranking of resources with that external cost level. Level two of external costs, compared to column 1 (internal costs) moves Colstrip, Hunter, Bridger, Craig, and Gadsby up in the rankings. Level two moves Johnston, Wyodak, Huntington, Hayden, Carbon, Naughton, and Centralia down in the ranking.

Column 4 shows total costs after the third level of external costs have been added, and the new ranking of resources. Hunter, Bridger, Craig, and Gadsby move up in the rankings. All of the other plants, except Colstrip, move down in the rankings, for later dispatch.

Column 5 shows total costs after the fourth level of external costs have been added, and the new ranking of resources. Hunter, Bridger, Craig, and Gadsby move up in the rankings. All of the other plants move down in the rankings.

Environmental dispatch would be highly influenced by CO2. Given the uncertainty of the external cost estimates for CO2 emissions, the Company has serious concerns about relying on any CO2 external cost estimates to drive environmental dispatch.

Plants are considered on the margin if their ranking would result in their being dispatched last -- only when load requirements were very high. Although each of the levels of external costs would move some plants up in the rankings and some plants down, the plants which would be on the margin under internal-cost only dispatch (Naughton and Centralia) would also be on the margin under environmental dispatch, and would be joined by Carbon under environmental dispatch. The overall conclusion from this analysis is that the lowest cost thermal units in terms of internal cost are also the Company's lowest cost thermal resources when external costs are added.

PacifiCorp - RAMPP 2

Existing Resources Without & With External Cost Adders
(Mills/KWh)
Table 4-20

			Internal Costs		Sensitivity-Level 1		Sensitivity-Level 2		Sensitivity-Level 3		Sensitivity-Level 4	
SO_2 $/ton			$0		$1000		$2000		$2000		$2000	
NOx $/ton			$0		$100		$4000		$4000		$4000	
TSP $/ton			$0		$200		$3000		$3000		$3000	
CO_2 $/ton			$0		$5		$0		$10		$30	
	Unit	MW/CF	[1]	Rank	[2]	Rank	[3]	Rank	[4]	Rank	[5]	Rank
Dave Johnston	1	105	7.14	1	19.18	7	29.89	8	42.06	10	66.39	10
	2	105	7.14	1	19.18	7	29.89	8	42.05	10	66.39	10
	3	210	7.01	1	19.24	7	33.20	8	45.12	10	68.97	10
	4	330	6.78	1	15.52	7	21.80	8	33.33	10	56.41	10
Wyodak	1	256	7.72	2	17.10	4	24.69	6	37.06	7	61.79	9
Colstrip	3	70	7.96	3	14.37	1	21.87	1	33.16	3	55.74	5
	4	70	7.96	3	14.37	1	21.87	1	33.16	3	55.74	5
Huntington	1	400	8.63	4	15.26	3	25.94	10	36.60	8	57.93	7
	2	415	8.62	4	17.87	3	31.18	10	41.83	8	63.14	7
Hayden	1	45	9.40	5	19.36	8	28.29	9	39.39	9	61.58	8
	2	33	9.41	5	19.53	8	27.65	9	38.72	9	60.87	8
Hunter	1	351	9.39	6	16.31	2	27.73	3	38.74	4	60.77	4
	2	234	9.64	6	16.47	2	20.15	3	31.44	4	54.03	4
	3	400	9.54	6	15.83	2	18.85	3	30.03	4	52.40	4
Carbon	1	66	9.98	7	21.86	10	37.10	13	49.37	13	73.91	13
	2	105	9.46	7	20.82	10	35.83	13	47.47	13	70.76	13

PacifiCorp - RAMPP 2

Existing Resources Without & With External Cost Adders

(Mills/KWh)

Table 4-20

			Internal Costs		Sensitivity-Level 1		Sensitivity-Level 2		Sensitivity-Level 3		Sensitivity-Level 4	
SO2 $/ton			$0		$1000		$2000		$2000		$2000	
NOx $/ton			$0		$100		$4000		$4000		$4000	
TSP $/ton			$0		$200		$3000		$3000		$3000	
CO2 $/ton			$0		$5		$0		$10		$30	
	Unit	MW/CF	[1]	Rank	[2]	Rank	[3]	Rank	[4]	Rank	[5]	Rank
Jim Bridger	1	346	10.80	8	17.97	5	23.90	4	34.66	5	56.18	3
	2	346	10.81	8	17.99	5	23.93	4	34.69	5	56.23	3
	3	346	10.80	8	17.91	5	21.70	4	32.45	5	53.97	3
	4	346	10.79	8	17.45	5	22.88	4	33.63	5	55.14	3
Craig	1	82	11.52	9	18.90	6	24.08	5	35.23	6	57.55	6
	2	82	11.54	9	19.38	6	24.22	5	35.40	6	57.75	6
Naughton	1	160	12.85	10	24.99	11	34.27	12	45.40	12	67.66	12
	2	220	12.87	10	25.24	11	42.24	12	53.40	12	75.73	12
	3	330	12.85	10	20.82	11	33.03	12	44.17	12	66.45	12
Centralia	1	304	14.04	11	28.62	14	46.00	14	57.11	14	79.35	14
	2	304	14.04	11	28.70	14	46.19	14	57.31	14	79.54	14
Gadsby	3	97	15.50	12	19.85	9	22.30	2	30.65	2	47.33	2
Cholla	4	350	17.72	13	27.14	13	32.90	11	44.27	11	67.01	11
Blundell	1	21	25.26	14	25.47	12	25.26	7	25.68	1	26.52	1

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OTHER UNCERTAINTIES: ILLUSTRATIVE PLANS

The Company also examined six other sensitivities to test the impact of additional uncertainties. All of these were based on the MH forecast of load growth. They include:

- Two sensitivities with a renewable resource focus,
- Two that examine demand side resource acquisition,
- One that assumes different hydro conditions, and
- One that reduces the performance of existing coal plants.

Graph 4-21 shows the resource additions by the years 2001 and 2011 for these six sensitivities. The order on the graph is different from the order listed here and in the rest of the Report, because Graph 4-21 requires ordering from left to right so that plans with high levels of certain resources do not "hide" the lower levels of resources in other plans. The sensitivities are:

Renew 20 Percent Less: Assumes that all renewable resources cost 20 percent less than they do in the other cases. It is depicted on the graph as "R20."

Renew Only: All coal and gas resources were removed from the portfolio, with the exception of cogeneration and solar with gas back-up. To compensate, additional wind and pumped storage were added to the portfolio. It is depicted on the graph as "Renew."

DSR -30: Assumes demand side resource acquisitions are 30 percent lower than the level assumed in the other cases that are based on the MH forecast. It is depicted on the graph as "DSR-."

DSR +30: Assumes demand side resource acquisitions are 30 percent higher than in the other cases that are based on the MH forecast. It is depicted on the graph as "DSR+."

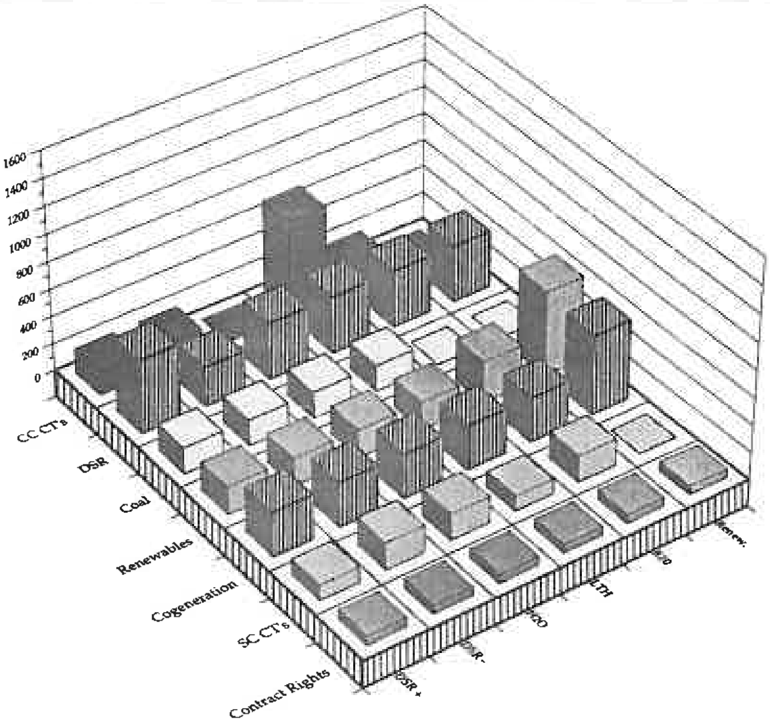
Average Hydro Conditions: Assumes the Company bases its planning on average hydro conditions rather than the critical hydro conditions assumed in the other cases. It is depicted on the graph as "H20."

10 Percent Less Thermal: Assumes the Company's thermal power plants operate 10 percent less than they currently do. It is depicted on the graph as "LTH."

Renewable Resource Focus

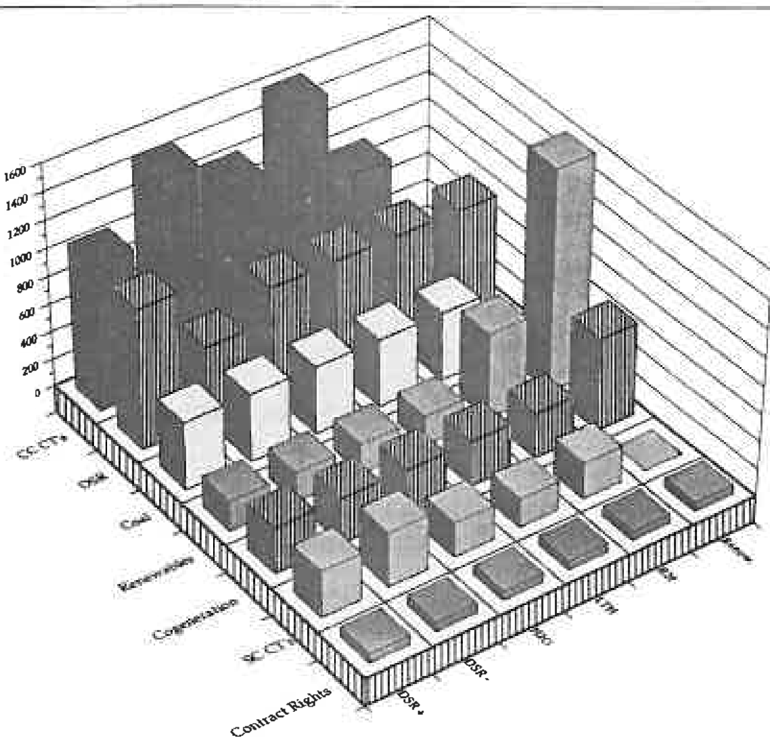
Sensitivities were performed to evaluate the impact on resource plans if all renewable resource costs were 20 percent less than expected, and if resource selections were restricted by removing from the portfolio all coal and gas resources except cogeneration and solar with gas back-up.

Other Uncertainty Sensitivities Total Resource Additions in MWa 1992-2001



Average MW's	DSR +	DSR -	H2O	LTH	R20	Renew.
CC CT's	175	175	0	700	175	0
DSR	543	293	418	418	418	418
Coal	192	192	192	192	0	0
Renewables	208	208	208	208	308	624
Cogeneration	330	330	330	330	330	585
SC CT's	114	201	195	110	197	0
Contract Rights	65	65	65	65	65	65
Total	**1627**	**1464**	**1408**	**2023**	**1493**	**1692**

Other Uncertainty Sensitivities Total Resource Additions in MWa 1992-2011



Average MW's	DSR +	DSR -	H2O	LTH	R20	Renew.
CC CT's	1050	1464	1225	1989	963	0
DSR	1016	547	781	781	781	781
Coal	492	492	492	492	492	0
Renewables	218	218	218	218	618	2258
Cogeneration	330	330	330	330	330	670
SC CT's	334	392	247	210	261	0
Contract Rights	65	65	65	65	65	65
Total	**3505**	**3508**	**3358**	**4085**	**3510**	**3774**

If renewable resources cost 20 percent less than expected (Renew 20 Percent Less), 618 MWa of renewable resources would be added instead of 218 as in MH4. To compensate for the peaking needs those renewables would create, more SCCTs would also be added: 436 MWa instead of 142. CCCTs would be substantially reduced from 1663 to 778, and a second coal plant would be added. The net effect would be an increase in system costs of about $300 million greater than MH4. Although renewables would cost less, more expensive resources would be required to meet peaking needs. Emissions would increase above those in MH4. Simply reducing the cost of renewable resources will not resolve complex planning issues.

If resource selections were restricted by removing from the portfolio all coal and gas resources except for cogeneration and solar with gas back-up (Renew Only), 2258 MWa of renewables would be added, and pumped storage would be included to meet peaking needs. Cogeneration would be increased from 330 MWa in MH4 to 670 MWa. No SCCTs, CCCTs, or coal plants would be included. The net effect would be an increase in system costs of about $2.5 billion compared to MH4. This increased system cost would result in significantly lower emissions than in MH4, particular for CO2. Whereas in MH4 CO2 emissions would increase by 32 percent, the Renew Only plan would see CO2 emissions increase by only 15 percent. However, these reduced emissions would come at a high price.

Demand Side Resource Acquisition

PacifiCorp has set ambitious goals for acquiring DSRs. The degree to which those goals can be achieved is uncertain. Demand side performance is examined through two sensitivity runs on the MH forecast case: One assumes that DSR programs acquire 30 percent less than the amount of resources expected, and the other assumes that DSR programs acquire 30 percent more resources than expected. The cost of DSR per unit of energy saved was not changed, but the total DSR costs would fall or rise according to the decrease or increase in resources acquired.

These cases should be compared to the MH step 2, as they are really variations on that case. As with step 2, the only forced variation from RIM model choices was the pilot renewable projects. The amounts of BPA Entitlement, cogeneration and renewables remain the same. As the following table shows, both more and less DSR increases the need for CCCTs, and additional DSR replaces the need for some CCCT resources.

	SCCTs	CCCTs	Coal
Medium High Step 2	263	1528	492
DSR Less 30 Percent	392	1464	492
DSR Plus 30 Percent	334	1050	492

Compared to MH4, system costs would increase by about $800 million if DSR acquisitions were lower than expected, and would decrease by about $200 million if DSR acquisitions were greater than expected. However, under both conditions, the price impacts would be small: -0.13 percent annually under MH4, -0.02 percent if less DSR was acquired, and -0.06 percent if more DSR was acquired.

Under lower DSR acquisitions, emissions would be higher than in MH4. Increased DSR acquisitions do not significantly reduce emissions, and the environment would not benefit from higher DSR levels.

If it began to appear that DSR acquisitions were well above or below expected levels, the Company would have adequate lead time to determine how to adjust its programs and/or its resource planning.

Hydro Conditions

Planning at PacifiCorp is based on critical water flows. Critical water is defined as the greatest amount of hydro energy that would be available to the region under historic dry conditions. Most utilities now define critical water as being stream flows like those that occurred between September of 1928 through March of 1932. Since the hydroelectric generation available during critical water conditions is a conservative estimate, critical water is often considered a synonym for firm hydro. The difference between average and critical water for the region is about 4000 MWa. The difference between average and critical water for PacifiCorp's hydro resources is about 150 MWa. While this is not an insignificant amount of power, it is only about one to two years of load growth.

Because the region usually has more water available than indicated by critical water levels, a sensitivity run was made on the MH forecast using average water conditions. An increased water flow would not substantially increase winter or summer peaking capability, but it would increase energy production. The resource plan assuming average water conditions included more SCCTs, fewer CCCTs, and an additional coal plant. Its 20-year system cost would be about $100 million higher than MH4. Its emission levels would be slightly higher than in MH4. Although planning based on average water would not have a major impact on system costs, it would increase the risks to the Company, and would be contrary to existing agreements with other utilities with which the Company shares reserves.

PacifiCorp believes it is more prudent to plan assuming critical water levels and deal with any surpluses either by displacing more expensive coal-fired resources or selling the surplus power on the spot market. The revenues from those sales are credited back to reduce the retail revenue requirement, and thus help maintain stable retail prices.

Existing Coal Plant Performance

Maintaining the current high operating availability of the Company's coal-based thermal plants may be increasingly difficult as the plants age. Coal plant performance is examined through a sensitivity run which assumes that the existing thermal plants operate at a plant capacity factor that is 10 percent less than the current level of about 85 percent.

If the existing thermal plants operate at 10 percent less operating availability, the system would need an additional 586 MWa in resources compared to the MH forecast case. The resulting resource plan would include more SCCTs, more CCCTs, and a second new coal plant. The 20-year system cost would increase by about $1.7 billion compared to MH4, and real price growth would increase from -0.13 percent to 0.24 percent. Although retail prices would increase faster than inflation, the rate would be less than from a high load growth forecast. Emissions would be higher for all four pollutants compared to MH4.

Keeping the existing thermal plants running at high availability is an important part of the Company's continuing effort to keep costs and prices to customers as low as possible. High availability also yields environmental benefits.

LOAD GROWTH UNCERTAINTY: ILLUSTRATIVE PLANS

Load growth uncertainty is perhaps the most difficult uncertainty in resource planning. One of the main reasons for using the Resource Integration Model to develop the illustrative plans was that it could synthesize and respond to "surprises." The Company wanted to be able to change its load forecast in the middle of the planning horizon, and test the effect on resource selections and system costs.

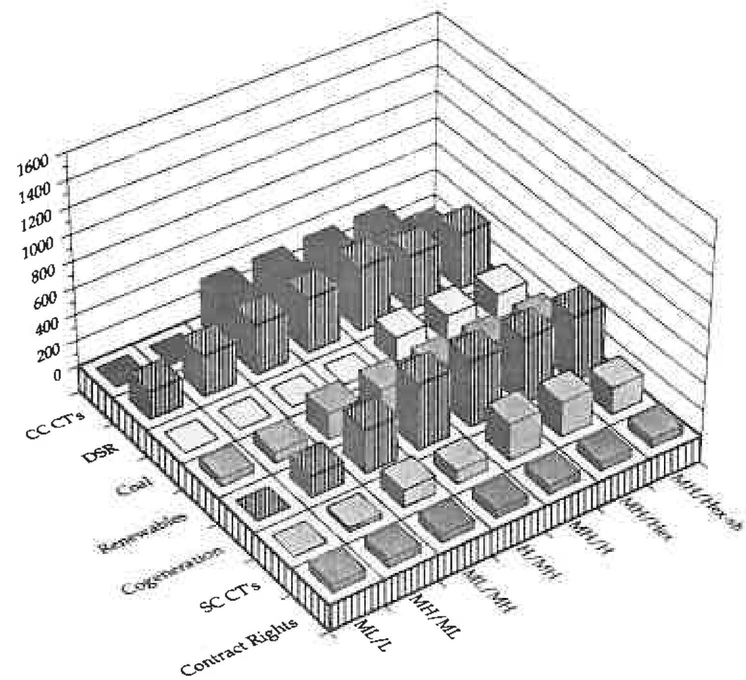
Introducing unexpected changes in load growth is one way to test the flexibility of different resource strategies. A particular load forecast is used for the beginning of the study period. The model makes resource decisions for the first year, then moves on to the next year. At that point, the model can be allowed to continue operating under the original forecast, or a new one can be introduced. If a new forecast is introduced, the model may go back and change some of its earlier resource decisions for those resources which were planned, but no commitments yet made.

The Company tested load growth uncertainty with seven "sensitivities" -- i.e., seven RIM runs. Graph 4-22 shows the resource additions for these sensitivity cases by the year 2001 and by the year 2011. The cases tested were as follows:

- ML load growth expected, low growth actually occurs, portrayed on the graph as ML/L;
- MH growth expected, ML growth occurs, portrayed on the graph as MH/ML;
- ML growth expected, MH growth occurs, portrayed on the graph as ML/MH;
- High growth expected, MH growth occurs, portrayed on the graph as H/MH;
- MH growth expected, high growth occurs, portrayed on the graph as MH/H;
- MH growth expected, high growth occurs from 1992 through 1998, then MH occurs from 1999 through 2005 (while the Company expects continued high growth), then MH occurs as expected from 2006 through 2011, portrayed on the graph as MH/Hex; and
- MH growth is expected, but high growth occurs from 1992 through 1996; then MH growth occurs from 1997 through 2011, as expected, portrayed on the graph as MH/Hex-sh.

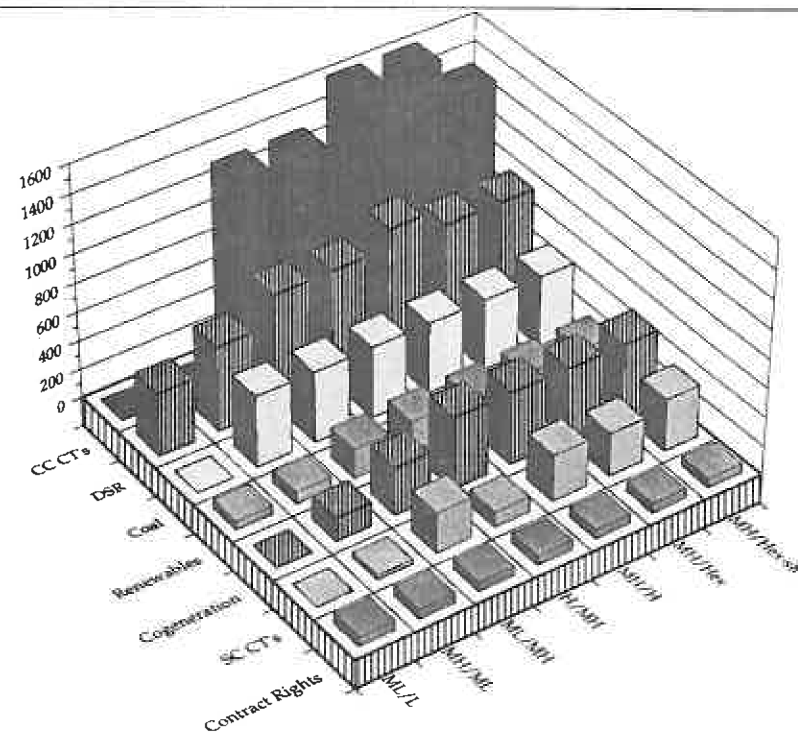
Graph 4-22

Load Uncertainty Sensitivities Total Resource Additions in MWa 1992-2001



Average MW's	ML/L	MH/ML	ML/MH	H/MH	MH/H	MH/Hex	MH/Hex-sh
CC CT's	0	0	350	350	350	350	175
DSR	213	316	381	417	486	418	418
Coal	0	0	0	0	192	192	192
Renewables	60	83	203	208	208	208	208
Cogeneration	0	161	330	501	500	500	500
SC CT's	0	31	134	99	278	267	205
Contract Rights	65	65	65	65	65	65	65
Total	**338**	**656**	**1463**	**1640**	**2079**	**2000**	**1763**

Load Uncertainty Sensitivities Total Resource Additions in MWa 1992-2011



Average MW's	ML/L	MH/ML	ML/MH	H/MH	MH/H	MH/Hex	MH/Hex-sh
CC CT's	0	0	1313	1313	3150	3214	1313
DSR	435	588	781	783	908	781	781
Coal	0	493	492	493	492	492	492
Renewables	60	83	203	218	218	218	218
Cogeneration	0	160	330	500	500	500	500
SC CT's	0	31	278	102	318	298	362
Contract Rights	65	65	65	65	65	65	65
Total	**560**	**1420**	**3462**	**3474**	**5651**	**5568**	**3731**

Medium Low Expected/Low Actual

The resource additions are quite similar to the low forecast case. Very few resources are added; thus this is not a good test of the impact of load uncertainty. The system cost is about $200 million higher than in the low forecast case.

Medium High Expected/Medium Low Actual

In the MH expected/ML actual case, the BPA Entitlement, DSR, and cogeneration are the same as in the ML forecast plan. The higher expected load growth leads to the cogeneration being added much earlier (in 1996 instead of 2009), and coal being added. Commitments are made to the two coal plants before the seven years of believing in MH growth is over, and the model is restricted from stopping them. However, in reality, the Company would not wait seven years to acknowledge that load growth was different than system cost is about $650 million higher than in the ML case, and retail prices decrease in real terms at close to the same rate.

Medium Low Expected/Medium High Actual

In the ML expected/MH actual case, the resource choices are very similar to MH4, except the load uncertainty case has more coal. System costs are about $150 million higher than MH4, and real prices decrease at -0.02 percent. We would expect that system costs would be lower than MH4; instead under-planning results in higher costs. It appears that under-planning results in system reserves which become quite low, resulting in the addition of additional resources beyond the level needed in the out-years.

High Expected/Medium High Actual

This is the companion case to the previous one, and allows a comparison of the costs of under-planning (the previous case) to over-planning (this case). The primary difference between the over-planning case and MH4 is higher amounts of cogeneration and coal in the over-planning case. System costs are about $100 million higher in the over-planning case. Over-planning results in slightly higher costs, but they are in the direction expected.

Medium High Expected/High Actual

The resource choices are similar to the high plan, except for higher levels of SCCTs, CCCTs, and coal in the uncertainty case. Under planning in this case resulted in a cost savings compared to the high plan, by about $100 million.

Medium High Expected/High Excursion

In the high excursion sensitivity, the system experiences high growth for seven years, and then experiences MH growth for the remainder. However, planners believe that high growth continues for a second seven years. The result is system costs that are about $3.5 billion greater than MH4, and $1.4 billion less than the high plan.

Medium High Expected/High Short Excursion

In the high short excursion, the system experiences high growth for 5 years, and then experiences MH growth for the remainder. Planners adjust their planning immediately. System costs can be compared to the high excursion, to see the benefits of early detection of a change in load growth. System costs are about $1.5 billion less than the high excursion case.

The system costs resulting from each case of load growth uncertainty fall between the system costs from the expected level of growth and the actual level of growth, except for the ML expected/MH actual. But the difference is too small to be significant.

The cost penalty or savings from under building or overbuilding is too small, and too inconsistent, to draw significant conclusions. The two excursion cases demonstrate the benefits of early detection of a change in load growth. All of the cases reveal that the costs of shifting levels of load growth are not high; the portfolio has sufficient flexibility to adapt to changes in the need for new resources. However, all of these results are based on an assumed access to a secondary market to both buy and sell power. Therefore, planning for a higher or lower load growth brings risks, because the prices on that secondary market cannot be assumed to be favorable. Those risks can be mitigated by activities in the long-term wholesale market. Those potential actions were not included in this modeling.

Each illustrative resource plan results in a reserve margin for each year of the planning horizon. In the Results Appendix those reserve margins are shown for each plan for winter peak and for summer peak. The reserve margins for each load uncertainty case can be compared to the margins from the resource plan for the corresponding forecast. For example, the ML expected/MH actual resource plan can be compared to MH4, the high expected/MH actual resource plan can also be compared to MH4.

The results of those comparisons indicate that the reserve margins in the load uncertainty cases deviate from the reserve margins of the corresponding forecast plan within a range of one percentage point to seven. For example, the reserve margin for the high expected/MH actual resource plan is 21 percent in 1995; the reserve margin for MH4 is 17 percent in 1995, for a difference of 4 percentage points. The difference is five or fewer percentage points for the two comparisons in most years. Under ML expected/MH actual, the system becomes over-built in the years after 2000. That occurs because the margins become too small in the early years, and so decisions are made to acquire additional resources to "catch-up." The Company could pursue seasonal exchanges or other wholesale arrangements to economically use any available power not needed for retail customers, but those transactions were not included in the modeling done for RAMPP-2.

A REVIEW OF GENERAL PATTERNS

The patterns that emerged from the four forecast cases can now be refined based on results from the scenarios and sensitivities.

Demand Side Resources

Since the real levelized cost of the DSRs is less than the real levelized cost of the resources on the supply side, the full amount of cost effective DSRs are included to meet system needs in all of the plans. The only cases which had different levels of DSRs added are the sensitivity cases with 30 percent more and 30 percent less, and the load uncertainty cases.

Renewable Resources

Because of the Company's new environmental goal, the illustrative plans all included an initial level of renewable projects. The model selected additional renewable resources beyond the 218 MWa in MH4 in only six of the other cases. Under high gas prices (two cases), the highest externality costs (two cases), or when renewables are assumed to cost less, the model adds 618-670 MWa of renewables. The last of the six cases is the Renew Only (when coal and gas resources were removed from the portfolio); the amount of renewables increased to 2258 MWa. Therefore, the pilot renewable projects and anticipated additions over the planning horizon are an appropriate amount unless gas prices increase significantly, the cost of renewables declines significantly, or greater consensus develops regarding appropriate actions to reduce CO2 emissions.

Peaking Resources

The model added SCCTs in all of the scenarios and sensitivities, except the low forecast case, the load uncertainty case with low actual loads, and the case which restricted resource choices by removing from the portfolio coal and gas resources. The SCCTs were generally added by 1996, and in the external cost cases by 1995. The total amount added over the planning horizon varied. In all of the MH and high cases the amount varied from just over 500 MW to over 2000 MW. The amount of SCCTs the Company will eventually need will depend on the course that load growth takes, and the other resources that are added to the system. Among the resource choices, SCCTs are well suited to meeting peaking requirements. The nature of other resource choices (for example, renewables) can require more peaking capability, or in the case of CCCTs, less peaking capability. However, the consistent timing of SCCTs being added in the various resource plans in the mid-1990s suggests that the Company should immediately pursue siting several hundred MW of SCCTs.

Cogeneration Resources

Cogeneration is included in all of the resource plans except the low load forecast. In all other cases, from 160 MWa to 840 MWa of cogeneration would be added by 2011. In all but a few of the cases, the model calls for 330 MWa of cogeneration. In the ML forecast case cogeneration is not called in until 2009, but in MH4 and almost all of the sensitivities based on the MH growth level, cogeneration is acquired in 1995. Therefore, it is timely for the Company to be pursuing cogeneration agreements with appropriate customers.

Gas-fired Resources

Cogeneration, SCCTs, and CCCTs make up a large part of the illustrative plans. The future price of gas will be critical in determining the actual timing and amount of gas-fired resources that are added to the system.

Gas prices are examined through the higher gas price scenario and through the sensitivity run on environmental costs which assumes higher gas prices. Those two cases demonstrate the dramatic effect higher gas prices can have on the cost competitiveness of gas fired resources. In MH4, 1872 MWa of gas-fired resources are added. In the high gas prices scenario, the total amount of gas fired resources is only 735 MWa, and 962 MWa in the sensitivity based on level 3 of external costs and high gas prices.

Fuel prices will be key economic factors for the remainder of the 1990s and through at least the first decade of the next century. In addition to gas price uncertainty, there is significant gas transportation uncertainty. Most experts predict that adequate gas supplies will be available from the United States, Canada and Mexico. The northwestern part of the United States can get its gas from Canada, Wyoming and New Mexico. The primary issue will be the availability of adequate transportation to move the gas from production fields to generating plants.

If the Company is faced with gas prices that are higher than expected, it will be forced to rely on more renewable resources. Renewables are currently more expensive and higher risk than CCCTs, because of their uncertain cost and performance. Gas prices will need to be closely tracked.

Coal Resources

By the year 2011, most of the cases have added a newly constructed coal plant. The exceptions are the low and ML forecast cases, CO2 tax scenario, environmental sensitivities (except for E1), and new renewables only sensitivity. Until more scientific consensus develops on the impact of CO2 on climate change, it is wise to keep the coal option open. The earliest on-line date for a new coal plant in any of the cases is 2001, MH4 includes coal in 2007, and the high forecast in 2002. With a lead time of seven years, a decision would not have to be made until 1994 at the earliest under any sensitivity, and most likely not until the year 2000. The actual decision year will depend on the rate of load growth that occurs. When a decision needs to be made, more information on load growth, the costs of alternative resources, and external costs will be available for making that decision.

Developing illustrative resource plans for these 26 cases has provided a wealth of information. Some of that information can be used to shed light on major issues that are facing the Company and the public. Key issues that have surfaced through the analyses in this chapter are discussed in the next chapter.

MAJOR ISSUES

Five major planning issues are discussed in this chapter:

- Growth and price stability,
- Environmental costs,
- Renewable resources,
- Peak versus energy planning, and
- Uncertainties.

GROWTH AND PRICE STABILITY

Growth and price stability are prime goals for PacifiCorp. While some are concerned that the two may be incompatible, the Company has developed a strategy to achieve both.

PacifiCorp is committed to providing competitive prices to customers, superior value to shareholders, career opportunities for employees, and responsible stewardship of the natural environment for society as a whole. To achieve these objectives, the Company has adopted strategic goals in four key areas: growth, customer service, continuous improvement, and the environment.

The growth goal says the Company will increase its business and shareholder value by increasing revenues from the sale of electricity, energy efficiency and other energy-related products and services. The goal says PacifiCorp will:

- Grow earnings available for common by an average of 3.5 percent per year, not including contributions from mergers and acquisition.
- Grow earnings per share by an average of 4 percent per year over the five-year planning horizon, including the contribution from merger and acquisition activity.
- Earn a return on assets that places the Company within the top one third of the electric utility industry.

Long-term earnings growth is essential to the Company's health. Utility investors expect competitive dividends paid on a regular and predictable basis. They also expect those dividends to increase over time to keep pace with the effects of inflation. When investors see PacifiCorp as a good investment, the Company is in a better position to borrow funds at a reasonable price and issue stock on favorable terms. This reduces the cost of financing and helps PacifiCorp maintain low electricity prices for customers. Even under lower load growth conditions, the Company has substantial capital financing requirements.

The Company can increase its revenues in a number of ways: by offering new products and services that meet customers' energy needs, increasing services which increase customers' energy efficiency, increasing the number of customers served, boosting economic development in local communities served by the Company, managing wholesale sales and wheeling, and achieving beneficial mergers and acquisitions.

PacifiCorp's strategic goals for 1992 call for keeping price increases below the rate of inflation after the Company's pledged period of price stability ends in December, 1992. The Company plans to keep future prices competitive by acquiring cost effective resources from the portfolio, through merger and acquisition activities, and continuing to improve cost management and operating efficiencies.

A strategy for growth can ultimately lead to a higher demand for electricity and the need to acquire additional resources. However, many new resources can be added at costs which do not dramatically affect total system costs. The RAMPP-2 results indicate that growth in electricity demand can be met without price increases greater than the rate of inflation.

By looking at how the retail price predicted by the RAMPP-2 modeling is expected to change over the next 20 years, the Company can analyze the price impacts associated with various levels of load growth and other uncertainties. In all forecasts other than the high-growth case, the Company could recover the costs of adding new resources without having to increase prices greater than the level of inflation. In the high-growth case, it would have to increase prices slightly more than the rate of inflation (0.33 percent real price growth per year). The only scenarios and sensitivities which result in significant price increases beyond the level of inflation are the electrification scenario (0.72 percent annual real price growth), the renewables only sensitivity (0.73 percent), and the MH forecast/high actual (0.47 percent). Three others had real price growth between 0.17 and 0.24 percent per year. The remaining 19 scenarios and sensitivities resulted in price increases less than the rate of inflation. Therefore, if one defines price stability as "keeping price increases at or below the level of inflation," PacifiCorp can maintain price stability in the face of load growth or uncertainties.

The Company believes that in the long run, the most successful companies will be those that provide superior customer service at a low cost. The Company is continuously seeking ways to provide the best value to customers, such as minimizing capital costs, improving productivity and efficiency, and improving the efficiency with which customers use electricity.

ENVIRONMENTAL COSTS

By examining the environmental impacts of the power system, the Company intends to help all those involved in resource planning more fully understand the complex trade-offs between internal and external costs. Perhaps the most common approach is to apply external cost adders to the internal costs of resources -- adding on an estimated external cost for specified emissions. The Company urges caution in the use of specific external cost adders which have been estimated outside the resource planning context. First, these numbers can have serious implications for consumers and retail prices. Second, emission levels themselves are variable and uncertain, as shown on Table 3-3 in the Portfolio

Chapter. Third, there is not yet a standard scientific method for measuring external costs. Four types of costs are generally considered in assessing the costs of external factors: damage, control, offset, and mitigation costs. The Company believes that if external cost adders are used, a least-cost approach should select the lowest cost among the four approaches for each emission.

The Company believes that analytical methods are available that do not require the addition of specific external costs at the beginning of the planning process. One such method is illustrated in the Illustrative Plans chapter, but the Company was unaware of how such a method could be incorporated in planning until quite recently. As a result, it was not possible to integrate such a method into this planning process. The Company plans to use this method more fully in RAMPP-3. PacifiCorp will continue to work with its seven state Commissions to develop a methodology that fairly includes environmental factors in planning.

A distinction should be drawn between the use of external costs in evaluating new resource additions, and the use of external costs in evaluating the acquisition of existing resources from other utilities. The contribution of existing resources to societal emission levels will be little changed by which utility has ownership or control over their output.

The use of external cost adders for specific emissions is not required for utilities to reach sound policy decisions. PacifiCorp management developed an environmental goal as one of its four strategic goals in 1992. The environmental goal was set after the Company considered the need for greater resource and fuel diversity, the need to reduce future risks from environmental regulations, and the need to act soon.

PacifiCorp has always believed that responsible environmental stewardship is good for the Company, its customers and stockholders. However, previous strategic goals did not include explicit environmental targets. The new goal says PacifiCorp will:

> "Continue to improve the management of our business operations as they affect natural resources and the environment. Seek new ways to expand Company programs that benefit the environment, while balancing the interests of customers and shareholders."

The goal calls for several specific actions, including:

- Help customers achieve annual savings of 170 MWa of electric energy by the end of 1996 through cost-effective DSR programs;

- Begin staged development of renewable resources with a target of 50 megawatts by 1996, expanding to 200 average megawatts by 2001 if proven cost-effective;

- Determine the cost and performance of utility-scale solar energy resources through participation in the Solar II demonstration project; and

- Investigate and test strategies to offset future increases in carbon dioxide emissions.

- Work cooperatively to formulate innovative regulatory measures to avoid regulatory impediments to the Company's pursuit of accelerated energy efficiency and renewable resources and air quality improvements.

RAMPP-2 analyses indicate that low external costs, or CO_2 external costs of $20/ton or less, have little effect on resource choices. A CO_2 external cost of $30/ton, however, would impact resource choices. The Company is particularly concerned about the use of external cost estimates for CO_2. While it recognizes that there is national concern over CO_2, the fact that there is still no consensus on the potential damage from CO_2 emissions makes it premature to assign high costs. The Company also feels it is premature to make major changes in resource choices based only on high external cost adders for CO_2.

RAMPP-2 results also reveal the difficulty in reducing emissions when a large existing system is involved. CO_2, SO_2, and TSP emissions increase in almost all cases, but less than the growth in GWh requirements over the 20 years. Only NO_x decreases.

Emissions were the lowest in all the cases under the low load growth forecast, but emissions would increase at almost the same rate as total GWh requirements. In all of the other cases, emissions would increase at a significantly lower rate than GWh requirements. The high load growth forecast did not result in significantly higher emissions than MH4.

The scenarios and sensitivities also revealed patterns in the relationship between emissions and load growth. In the loss of resources scenario, emissions were higher than in MH4. This is a case where efforts to help one aspect of the environment (fish species) could lead to adverse environmental consequences in another area (air emissions). High gas prices would have adverse environmental impacts. Under the scenario for high gas prices, emission levels are higher than in MH4 for all four categories of emissions. A CO_2 tax of $30/ton, or resource choices assuming an external CO_2 cost of $30/ton, would reduce emission levels, but at a high cost to society. Reducing the cost of renewables, so that more are selected, does not necessarily decrease emissions, because additional SCCTs are needed to provide capacity that the renewables don't provide. Restricting resource choices by avoiding coal and gas-fired resources reduces emissions dramatically, but at a very high cost. No real gain of lowered emissions occurs with the increase in DSR acquisitions. If the existing coal plants operate at 10 percent less availability, emissions would be consistently higher for all four pollutants compared to MH4.

Any evaluation of the trade-offs between system costs and emissions also needs to consider the trade-offs between other environmental goals and other operating conditions.

An additional analysis was performed to illustrate the benefits of a methodology which does not require external cost adders at the beginning of the planning process. This form of analysis can help identify the cases which provide increased environmental benefits at lower system cost. All of the cases that were based on the MH growth rate were plotted, to show the total system costs relative to the level of emissions. The three resource plans with both lowest system cost and lowest emissions were MH4, E2, and E3. The resource choices included in E2 and E3 differ from the resource choices in MH4 in three primary ways: E3 has more renewables than MH4, and both E2 and E3 have no new coal plants, whereas MH4 includes one new coal plant. Through the remainder of this century, E2, E3, and MH4 have the same level of renewables, and no new coal. Thus for these next ten years, the resource choices for E2 and E3 are very similar to the resource choices for MH4. The actions that the Company is planning in the near future are appropriate for both minimizing system costs and minimizing emissions.

RENEWABLE RESOURCES

The term renewable resources typically refers to the conversion of geothermal, wind, or solar energy to electricity. In addition, hydroelectric and biomass generation are derived from renewable resources; geothermal (ground source as opposed to air-to-air) heat pumps can also be considered a renewable resource. The determination of when renewable resources are cost effective depends in part on the relative costs of other resources.

PacifiCorp could bring renewable resources into production by developing those resources itself, acquiring them from developers, or simply purchasing their output. The Company is not in a position to affect the cost-effectiveness of renewable resources through its own technological research and development. PacifiCorp will continue to rely on the industries that support renewables for technological advancement, and will monitor those improvements. The Company does believe it should identify the transmission limitations and system constraints that would apply to potential renewable resource sites. It will continue to support cooperative research where that research will benefit the Company.

Consistent with PacifiCorp's environmental goal, pilot renewable projects for wind and geothermal are included in all resource plans except the low forecast cases. All but the low cases include 148 MWa of wind and geothermal by the year 2000, with wind coming on line in 1996-97, and geothermal in 1998. The cost to the system of these pilot projects can be determined by comparing the system costs for the MH forecast step 1 versus step 2. Step 1 was an untouched model run; step 2 added the pilot renewable projects, but made no other changes to the modeling inputs. The difference in system costs was about $150 million.

The Company's senior management decided to include pilot renewable projects as part of the environmental goal after weighing the costs and benefits. The benefits of renewable resources include potential environmental benefits from no air emissions, resource diversity, the ability to site small units, short lead times, and potential ease of siting and licensing. The benefits of early action on renewables can include improving technical staff capability, reducing cost and performance uncertainty, and identifying and eliminating institutional or regulatory barriers that could impede development. To capture these benefits, the Company needed to develop attractive resource sites on a realistic demonstration scale. The pilot projects will help the Company ramp up renewable resources based on actual experience and confirmed cost and performance.

PacifiCorp has examined the impact of renewable resources on planning through a sensitivity run that removed coal and gas-fired resources from the portfolio. This restriction resulted in 2258 MWa of renewables being added to the system by 2011, for a system cost of $2.5 billion more than MH4. Emissions reductions were most pronounced for CO_2, less so for NOx and TSP, and almost non-existent for SO_2. Another sensitivity assumed that renewable resources cost 20 percent less. This resulted in the addition of about 400 MWa more in renewable resources than MH4, for a system cost of about $300 million more than MH4. Emissions were less than MH4 for CO_2 and NOx, but were higher for SO_2 and TSP. Thus, reducing the cost of renewables is not the answer to lower emissions and lower system costs.

PacifiCorp has pledged $1 million to help fund the Solar II project -- the Company's first financial commitment to solar technology. This project will be jointly funded by the U.S. Department of Energy and a consortium of utilities. The $39 million Solar II project is scheduled to be on line in early 1995. It will operate as a test facility for three years, run by Southern California Edison. While expected to generate only 10 MW, Solar II will demonstrate a new technology that uses molten salt to store the sun's energy, which will in turn power a steam turbine. Anticipated benefits include greater knowledge of the costs, benefits and obstacles involved in making solar energy commercially viable, and improved expertise in the design, construction and operation of such facilities.

CAPACITY VERSUS ENERGY

RAMPP-1 focused primarily on **energy** needs -- the kilowatt hours needed to serve customers. Each resource that was evaluated also offered a certain contribution to **capacity** -- the amount of electricity the system can provide to meet the highest level of aggregate customer demand at any given time. Additions to capacity occurred as energy resources were added in each load growth case. They allowed the Company to meet peak (capacity) requirements and maintain sufficient reserves.

The Company recognizes that peaking needs as well as energy needs will drive resource decisions. The Company's earlier assessment of the cost effectiveness of DSRs did not adequately address the impact of those resources on capacity. Therefore, the cost effectiveness methodology was changed during RAMPP-1 planning to include capacity, and that approach was expanded in RAMPP-2. The modeling for RAMPP-2 adds resources based on their ability to meet both energy and capacity needs. For example, as the DSRs are added, they reduce the remaining energy and capacity needs that must be met by other resources.

The conventional utility peaking resource is a simple cycle combustion turbine - SCCT. Hydro is often thought of as the best peaking resource, because it can be increased to match load most effectively. SCCTs can be used to match load also, but hydro can be ramped up or down more quickly to respond to changes in load levels. An SCCT cannot replace hydro, but it is the resource alternative that provides benefits most similar to hydro. SCCTs offer other advantages as well, including their flexibility for expansion and for using other fuels. Additional capacity or efficiency can be obtained by adding a heat recovery steam generator and a steam turbine to a combustion turbine and creating a combined-cycle system. A gasifier can be added to create an integrated gasification combined cycle (IGCC) system to use coal, if natural gas becomes too expensive.

SCCTs are prominent in most of the illustrative plans and in most of the sensitivity runs for meeting peaking needs. In one case, when coal and gas-fired resources are avoided, pumped storage is selected. However, pumped storage requires off-peak generation to provide the power to pump the water up to the reservoir, so the water can be re-used to provide capacity during peak hours.

In all of the cases except the low and ML load growth, low load uncertainty, and no coal or gas sensitivity, SCCTs are added by 1998, usually by 1996. In all of the MH and high cases the amount varies from just over 500 MW to more than 2000 MW. Under MH load growth, the Company plans to have about 400 MW of CTs operating in 1996, and about 850 MW by 2000. The amount of SCCTs the Company will eventually need will depend on load growth, and the other resources that are added to the system. Other resource choices can require more peaking (for example, renewables), or less (for example, CCCTs). The diverse sensitivities tended to add in SCCTs in the mid-1990s; this suggests that the Company should immediately pursue siting several hundred MW of SCCTs.

With the increasing importance of capacity needs highlighted by RAMPP-2, PacifiCorp recognizes the need in future planning to examine competitive alternatives to SCCTs, including pumped storage and load management.

UNCERTAINTIES

Given the amount of uncertainty that exists in the energy marketplace and in the economy, a host of possible futures must be considered. PacifiCorp has developed illustrative resource plans for multiple forecasts, scenarios and sensitivities to address future uncertainty. The illustrative plans in RAMPP-2 illustrate how the power system would grow, over time, using reasonable planning criteria under various future conditions.

The chapter on Illustrative Plans provided two key conclusions related to future uncertainties : first, PacifiCorp's portfolio is sufficiently flexible to provide resource plans at reasonable costs for a wide range of load growth levels over the next 20 years; and second, if the Company plans for load growth that turns out to be slightly different than what occurs, the cost impact will not be severe. A related question is whether it is better to over-build or under-build. Over-building results in slightly higher costs, but they are in the direction expected. Under-building results in higher costs also. The system cost under each case of load growth uncertainty falls between the system cost under the expected level of growth and the actual level of growth, except for the ML expected/MH actual. But the difference is so small, it is not significant. No definitive conclusions can be reached to answer this question, although under-building can lead to "catch-up" resource additions that result in higher system costs.

Fuel will be a key economic issue in the 1990s and 2000s. PacifiCorp recognizes the uncertainties of fuel cost and availability. Its existing coal contracts make coal costs and availability more certain. However, gas prices, availability, and transportation are quite uncertain. Higher gas prices will have adverse impacts on system costs, retail prices, fuel diversity, and air emissions. Gas prices will need to be closely tracked because of their significant impact on resource decisions.

PacifiCorp has set ambitious goals for acquiring DSRs. The degree to which those goals can be achieved is unknown. Nevertheless, the Company's analysis indicates that if it is unable to acquire the targeted amount of DSRs, the cost impact on customers will be small.

The Company conducts its planning based on critical water years (i.e., it assumes the lowest levels of water will be available for hydro). Although planning on average water would not have a large system cost impact, it would increase risks to the Company and is contrary to existing inter-utility reserve sharing agreements.

A related uncertainty is the degree to which the Company can rely on its own hydro facilities and those of others in the region to meet peaking demand. If the region decides to alter hydro operations to protect various fish species, electricity prices will increase.

PacifiCorp's coal plants operate at a higher capacity factor than the national norm. The Company has evaluated how operating costs and retail prices would be affected if those high performance levels could not be maintained. The results indicate the Company needs to keep its thermal plants running at high availability levels in order to help keep its costs and its prices to customers as low as possible.

To manage these uncertainties, PacifiCorp is pursuing strategies to minimize the risk of a faulty assumption on load growth or the other uncertainties discussed here. The Company is currently in dynamic balance -- i.e., its level of supply is comfortably close to the level of electricity needs. The Company is committed to maintaining that balance, despite the uncertainties of load growth and resource costs and availability.

PacifiCorp's strategy is to develop and maintain flexible options and a diverse portfolio of resources. The results of the scenarios and sensitivities show that the portfolio has sufficient flexibility to respond to an uncertain future. The Company's strategy includes three approaches:

1. **Acquire "low-regret" resources.** These are resources that are beneficial regardless of the level of load growth, such as DSRs and combustion turbines (particularly SCCTs in the short term).

2. **Emphasize resource diversity**, including DSRs, the lowest-cost renewables and gas-fired resources.

3. **Assure flexibility and acquire resources that are optional and/or have short lead times.** Maintain the ability to adapt to changes in need and economics or in the performance of new resources. Cost effective resources acquired through merger and acquisition activity on a "lost opportunity" basis would be applicable here.

ACTION PLAN

This chapter summarizes the progress the Company has made in implementing its RAMPP-1 action plan, and describes the RAMPP-2 action plan. The RAMPP-2 action plan includes the steps the Company will take in the next two years to acquire the resources needed during that time and to prepare for acquiring resources in ensuing years.

RESULTS OF RAMPP-1 ACTION PLAN

Since RAMPP-1 was published two years ago, Pacific Power and Light and Utah Power and Light have successfully merged into one company. From the beginning, planning and operations have been based on the needs and characteristics of the combined system. Planning for RAMPP-2 has been enhanced by the Company's additional experience operating the merged system.

The Company's RAMPP-1 short-term action plan called for:

- Proceeding with customer energy efficiency programs;
- Proceeding with system efficiency programs;
- Testing the wholesale marketplace and securing cost-effective resources;
- Preparing to implement firming strategies; and
- Addressing future planning issues.

Progress on Customer Energy Efficiency Programs

PacifiCorp is on schedule in implementing the demand side activities in the RAMPP-1 action plan. The RAMPP-1 programs have generally achieved their goals and estimated energy savings. Those programs have achieved better penetration than anticipated for new construction (i.e., the percentage of new electric homes being built to high efficiency standards has been greater than expected) and for water heating efficiency.

The pilot project for retrofitting commercial buildings has achieved more energy savings per building though fewer buildings have participated than expected. The new construction programs have achieved penetration goals but new home construction has been less than forecast. The pilot programs for residential retrofits and industrial customers have taken longer to initiate than anticipated.

The 1990-1991 preliminary budget estimate for PacifiCorp's expenditures on DSR programs was $25.8 million; the actual budget was $20.3 million. The preliminary goal for energy savings was 10.6 average megawatts; the estimated savings actually achieved was 8.7 MWa. The greatest differences between goals and amounts achieved were in the industrial sector, where only 1.0 MWa of savings was achieved out of the 3.8 MWa goal, and in appliances, where an energy savings of 1.7 MWa was achieved, higher than the goal of 0.2 MWa.

All of the tables and detailed information provided in this chapter use MWa (energy) savings numbers. However, these DSR programs produce capacity savings as well. Those capacity savings are included in the modeling results and in the Company's targets. In order to be succinct, the information in this report is provided in terms of energy rather than energy, winter capacity and summer capacity. The corresponding capacity data is available in the Demand Side Technical Appendix.

New Residential Buildings

Super Good Cents has achieved an extraordinary penetration rate of 80 percent (i.e., 80 percent of new electric homes are included in the program). PacifiCorp's implementation of the program has the highest success rate of any large utility. This success has contributed to the acceptance of Model Conservation Standards (MCS) in Oregon and Washington. PacifiCorp is supporting efforts to examine and adopt MCS in Idaho and Montana. The Company is also supporting a program to provide incentives to mobile home manufacturers to encourage them to build their manufactured homes to high efficiency standards.

Following are the RAMPP-1 action steps related to new residential buildings, and the Company's progress on those activities:

	Action Step	Progress
1.	Continue Super Good Cents Program. Achieve 45% penetration in 1990, 60% in 1991.	Reached 54% penetration in 1990, 80% in 1991.
2.	Extend Super Good Cents to Utah by 1991. Achieve 30% penetration. in 1991.	Tariff filed, program piloted Penetration goal expected to be met by 1994.
3.	Support codes to adopt MCS in Northwest.	Codes adopted in Oregon and Washington. Under consideration in Idaho, Montana.
4.	Operate pilot program to improve manufactured home setups. Achieve 50 manufactured homes per year.	Achieved 75 manufactured homes in 1990, 542 in 1991.
5.	Support MCS standards for manufactured homes.	Program to acquire energy savings from manufactured homes expected by mid-1992.

6.	Evaluate solar access for new housing.	Passive cooling analysis completed. Training provided to local planning officials to include solar access considerations in their planning.

Residential Weatherization

Residential weatherization has mainly been achieved through the existing low-interest loan programs. PacifiCorp will increase support of community agency-sponsored weatherizations in 1992. In addition, PacifiCorp will conduct a test of performance bidding for low-income weatherization in Oregon from 1992 to 1995. In performance bidding, independent contractors submit bids based on the knowledge that they will be paid according to the results of the program.

PacifiCorp has also developed "Home Comfort" as a pilot program for residential weatherization. It has been launched in Washington to capture 4.5 MWa by 1996; Home Comfort programs are also being initiated in Oregon and California. The program is intended to update retrofit procedures based on new techniques and knowledge. In addition, the program tests the acceptance to customers of different Energy Service charge options, in which customers repay the Company for weatherization measures with part of their savings from increased energy efficiency. This mechanism allows PacifiCorp to provide full financing while minimizing retail price impacts on non-participants.

	Action Steps	Progress
1.	Achieve proportional low-income participation. Support full weatherization of 3,000 homes.	Achieved weatherization of 2,231 homes.
2.	Pilot new weatherization program which targets customers with high savings potential and achieves 600 participants.	In progress. Achieved 14 participants.
3.	Demonstrate feasibility of shared savings.	In progress.
4.	Demonstrate method to accurately estimate and measure savings.	In progress.

Residential Appliances

PacifiCorp has continued to support the Northwest Regional Appliance Group. That group has made progress in improving the standards for water heaters to an energy factor (EF) rating of .95 (95 percent efficient under certain test procedures). This is a direct result of PacifiCorp's purchase of efficient units for the "Hassle Free" water heater program. Also under the Hassle Free program, PacifiCorp distributed more than 20,000 low-flow shower heads to participating customers. These shower heads account for the largest amount of appliance-related savings. PacifiCorp will support the upcoming "Golden Carrot" program to encourage manufacturers to produce highly efficient refrigerators, and will continue to support BPA's "Blue Clue" program which recognizes distributors for selling high-efficiency appliances.

PacifiCorp purchased chlorofluorocarbon (CFC) recycling equipment and uses it in Medford, where the Company conducts a consulting and training service called "H-Pro" for heat pump dealers. The H-Pro program resulted in 200 technicians receiving national certification and 125 becoming re-certified.

	Action Steps	Progress
1.	Seek regional program for joint purchases.	Participating in Northwest Appliance Efficiency Group. Promoted .95 EF standard for water heaters.
2.	Continue to support Blue Clue program.	Achieved.
3.	Upgrade water heaters under "Hassle Free" program. Achieve 6,000 installations.	Installed 8,220 water heaters, 22,186 shower heads.
4.	Test water heater load controls.	Achieved.
5.	Hold advisory group meetings to ensure that marketing programs promote the most efficient products.	Achieved.
6.	Study feasibility of CFC and PCB recycling and proper disposal.	Purchased CFC recycling equipment for heat pump training, available to H-Pro dealers.

New Commercial Buildings

PacifiCorp's new commercial program, called "Energy FinAnswer," offers developers full financing for efficiency measures, which has resulted in high levels of customer acceptance. Energy FinAnswer achieved 11 percent penetration in 1990 and 30 percent in 1991, exceeding its initial goals. Tariffs for the program, which incorporates the Energy Service charge, have been approved in Oregon, Washington, Idaho, Utah and California. Pacific estimated that participants would achieve energy savings of 5.7 kWh/square foot, which is the full technical potential.

	Action Step	Progress
1.	Operate the new commercial building program in Oregon and Washington. Extend to other states by 1991.	Program operates in Oregon, Washington, Idaho, California and Utah. Design service operating in Montana.
2.	Examine extension of program to commercial remodel lost opportunities.	Program extended to include major remodel.
3.	Support field staff and integrate Energy FinAnswer into field activities.	Achieved.

4.	Achieve penetration rates of 1 percent in 1990, 11 percent in 1991.	Reached 11 percent in 1990 evaluation, 30 percent in 1991.
5.	Support commercial MCS in Northwest.	In progress.
6.	Demonstrate shared savings program operation.	Shared savings successfully demonstrated.

Commercial Retrofit Program

PacifiCorp piloted its commercial retrofit program in Albany, Oregon. The program offers participants professional assistance with lighting, HVAC (heating, ventilation and air conditioning) and interior design. To emphasize these benefits, the program is called "Pacific Environments." It provides full financing for efficiency measures with repayment through an Energy Service charge. Pacific Environments has completed about 70 audits. Of those, about 20 retrofits have been completed. Twenty-four of the audited customers have declined to participate, but three will implement the conservation measures on their own. The remainder are in some stage of considering the offer. Energy savings per participant have been somewhat greater than expected.

	Action Step	Progress
1.	Operate Pacific Environments in medium-size city. Achieve 100 participants by 1991.	Albany selected as pilot site. Audited 70 participants by 1991, 18 completed projects by 1991.
2.	Offer advanced assistance in lighting and interior design.	In progress.
3.	Demonstrate shared savings program operation.	Shared savings demonstrated successfully.
4.	Demonstrate method to accurately estimate and measure savings.	In progress.

Industrial Sector

The industrial program, "Energy Partners," is in its early developmental stages. Through the program, PacifiCorp will offer full financing for efficiency measures and an Energy Service charge that is equivalent to a loan at the prime rate plus 3 percent. A major hurdle in implementing the program is reaching the appropriate decision-makers in a given industrial company. The program is now being redesigned to work directly with corporate executives. Thus far, Energy Partners has conducted seven design studies and experiments. Of those, one participant has signed up for the financing. However, three participants are implementing the recommendations using their own financing. As a result, the program has been successful in achieving energy savings goals although participation has been slower than expected.

	Action Steps	Progress
1.	Develop new program. Conduct studies and implement program at four facilities. Achieve five major participants.	Achieved.
2.	Develop industrial sector data base.	In progress.
3.	Integrate efficiency programs into customer contacts.	In progress.
4.	Demonstrate shared savings program operation.	In progress. Initial results support shared savings concept.

Progress on System Efficiency Programs

The Company has begun implementing various system efficiency programs which were identified as cost-effective resources in RAMPP-1. These improvements are on schedule, and are to be implemented over the next 10 years. For that reason, they are included in RAMPP-2 as part of the existing system rather than as new resources. The Company plans to implement the following levels of efficiency improvements: 4 MWa in 1992, 10 MWa in 1993, and increasing each year to reach 84 MWa in 2001.

Progress in Securing Cost Effective Resources from the Marketplace

In the area of power purchases, RAMPP-1 called for the Company to identify and secure specific long-term firm purchase opportunities with costs comparable to those in the resource portfolio, if those purchases might become lost opportunities, and to develop and test contractual arrangements with the most cost effective cogeneration candidates. PacifiCorp has acquired existing generating facilities and other integrated arrangements through two transactions completed in 1991. One series of agreements is with Arizona Public Service Company (APS); the other involves certain generating facilities of Colorado-Ute Electric Association. Negotiations are continuing with cogeneration candidates.

The RAMPP-1 action plan identified a need to test the broader marketplace through a trial competitive bidding process consistent with Washington and Oregon Commission rules. The Company issued a request for proposals for 50 MW of resources in June of 1991. Bids for those resources were due on February 28, 1992. In April, 1992, a short list was announced. The short list is now being evaluated and the bids ranked.

Progress on Firming Strategies

In preparing to implement firming strategies, the Company planned to modify maintenance procedures at its thermal plants to derive more firm energy from the coordinated hydro-thermal system. The Company also took the necessary steps to be able to re-start the Gadsby Plant within one year of a decision to do so. PacifiCorp has changed the maintenance schedules on its thermal plants from a 12-to-18 month schedule to an 18-to-24 month schedule, freeing the plants for more firm energy output. The Gadsby Plant began operating with natural gas in April of 1991.

Progress on Future Planning Issues

To prepare for future planning, the Company reviewed the adequacy of information on potential renewable resources. In January of 1991, the Company filed with the Oregon Commission a report on its assessment of renewable resources, and planned activities to further develop of those resources.

The Company also said that it would improve its ability to evaluate new resource alternatives and planning strategies, taking into consideration major uncertainties. In this second round of RAMPP, specific analyses of uncertainties were conducted. They are described in the section on uncertainties in the chapter on Illustrative Plans.

RAMPP-2 ACTION PLAN FOR 1992 AND 1993

The RAMPP-2 analyses show that a broad range of alternative resources can be relied on to meet future needs, but the actual amount and timing of new resources will depend on how the future unfolds. Fortunately, most decisions to acquire new resources over the next 20 years do not need to be made immediately. Nevertheless, some actions are necessary in the short term to prepare for the long term.

The action plan was developed after analyzing the results of the illustrative plans, input from the RAMPP Advisory Group, and input from the Company's upper management. The primary goals of the action plan are to implement DSR acquisitions to be ready for ramp-up in the mid-1990s, prepare for acquisition of renewable resources, increase the Company's peaking resources, and pursue cogeneration possibilities. These actions will give the Company the flexibility it needs to respond to uncertain load growth.

The action plan is based on the assumption that load growth for at least the next two years will be within the range of ML to MH. If load growth occurs outside that range, the Company will reassess its action plans. However, DSR activity in the next two years would not be affected by level of load growth, because that activity level is based on the Company's desire to be ready for full ramp-up of DSR programs in the mid-1990s. The renewable pilot projects would also be continued because the Company sees a continuing need to gain experience and knowledge with those technologies. If load growth in the next two years were lower or higher than expected, the BPA Entitlement contract provides some flexibility, as do contract negotiations with potential cogenerators.

One of the primary uncertainties facing PacifiCorp is how much cost effective resource it can acquire from existing utilities through mergers and acquisitions. If cost effective M&A opportunities arise, the Company will pursue them. The action plan might then need to be modified. However, the Company would not plan to modify its demand side or renewable activities. Those actions are needed, regardless of other resource acquisitions, so the Company can acquire the experience and knowledge needed to pursue such resources in the future.

PacifiCorp believes that with the portfolio of resource options identified in RAMPP-2, it can manage situations that may arise outside of the forecast cases. For example, if the future brings very low load growth, the flexibility built into some of the resource options would allow the Company to maintain reasonable levels of resources and sell any residual surplus through the Company's access to other markets. If load growth is significantly greater than the high case, the Company's resource portfolio contains sufficient resources that could be activated on short notice to sustain a modest period of higher-than-expected growth without dramatic retail price impacts. These short-notice resources include SCCTs and some renewable resources.

Action Steps

1. **Continue to increase the amount of demand side acquisitions. Achieve 27 MWa of savings by the end of 1993.** By sector, the MWa savings goals to be achieved by 1993 are as follows:

Residential Weatherization	4.9
New Residential	1.9
Commercial Retrofit	4.6
New Commercial	7.8
Industrial	7.1
Appliance	0.9
Irrigation	0.2
Total	27.3 MWa

Since the real levelized cost of the DSRs in the portfolio is less than the real levelized cost of the resources on the supply side, the full amount of the cost effective DSRs is included in all of the plans. Programs to achieve the savings listed above are described below. Additional details, such as specific budgets and goals for each program, are provided in the Demand Side Technical Appendix.

2. **Determine actions needed in 1992 and 1993 to have 125 MW of wind capacity (40 MW effective capacity) in operation by 1996-97, and pursue those identified actions.**

The analyses discussed in the Illustrative Plans chapter indicated that the pilot renewable projects and the additions anticipated over the planning horizon are appropriate unless gas prices increase significantly, the cost of renewables declines significantly, or greater consensus develops regarding the impact of CO2 on climate change. The Company recognizes that the next step in the pursuit of renewable resources is to acquire some and learn from the experience. Therefore, it will determine what actions are needed in the next two years, and pursue those needed to achieve some wind capacity by 1996-97. Although the illustrative resource plans indicate additional renewable resources will be added on a regular schedule over the planning horizon, those plans will be re-evaluated as additional information becomes available. Therefore, the performance and costs of the pilot projects will determine whether the original schedule for acquisition of renewable resources is maintained or adjusted.

3. Sign confidentiality agreements for one or more potential sites to analyze the feasibility of bringing 50 MW of geothermal capacity on line by 1998.

Again, the company recognizes that near-term steps are required to acquire renewable resources in this decade. While development of the Blundel plant in Utah has provided valuable experience with geothermal resources, the Company needs site-specific information on cost and feasibility of additional geothermal resources, including potential sites in the Pacific Northwest.

4. Determine the cost and performance of utility-scale solar energy resources through participation in the Solar II demonstration project.

PacifiCorp has agreed to be a primary sponsor and has pledged $1 million from 1992-1994 to help fund the Solar II project. The Company will have a representative on the Project Steering Committee and the Technical Review Committee. PacifiCorp's objectives will include determining the cost and performance of utility-scale solar thermal technology.

5. Initiate siting, permitting, and procurement for up to 450 MW of SCCTs. Operational and resource uncertainties may require more CTs. Seek permits which allow some of the SCCTs to be converted to CCCTs units if needed.

Recognition of the Company's peaking needs has led to a commitment to acquire additional peaking resources. Depending on the forecast, scenario, or sensitivity being tested, most of the resource plans show SCCTs coming on line in 1995 and 1996. The total amount added over the planning horizon varies. In all of the MH and high cases the amount varies from just over 500 MW to over 2000 MW. The amount of SCCTs the Company will eventually need will depend on load growth, and the other resources that are added to the system.

SCCTs may be needed to meet general load-following needs, take better advantage of transmission resources, protect against the risk of reduced peaking availability from hydro resources as a result of fish concerns, and provide peaking needed for renewable resources which are not suited for load following. Other resource choices may require more peaking capability (for example, renewables), or less (for example, CCCTs). SCCTs offer the advantage of being flexible for expansion. Additional capacity or efficiency can be obtained by adding a heat recovery steam generator and a steam turbine to create a combined-cycle system. The system can also be converted to run on coal, if natural gas becomes too expensive.

The locations for SCCTs currently under consideration are on PacifiCorp's west side (Oregon or Washington), east side (Utah or Wyoming) and in Arizona. In these locations the SCCTs would be near loads as well as existing transmission. However transmission capacity constraints can at times limit power flow between east and west side and limit the ability to serve loads. Future studies will investigate how potential locations can most cost effectively fit with the existing system.

6. Implement the decision to acquire 150 MW of peaking resources in Arizona Public Service Company's service area. Determine whether CTs or renewable resources are more cost effective. Initiate siting, permitting and procurement.

As part of the Company's agreement with APS, 150 MW of resources will be constructed in the Arizona area by the end of 1996. Such resources are consistent with the need for SCCTs described in Action Step 1, above. The Arizona Corporation Commission has requested that the Company investigate the feasibility and cost-effectiveness of using a renewable technology, such as wind or solar, for that resource. Therefore, the first step is an investigation of the cost and benefits of renewable versus a conventional combustion turbine. The next step will be to pursue siting, permitting and procurement of equipment for whichever technology is chosen.

7. Sign intent agreements and pursue contract negotiations with industrial customers to achieve to 300 MWa of cogeneration on line by 1997. Build in options to accelerate or delay construction to allow for load growth uncertainty.

Cogeneration is included in all of the plans except the low load forecast, ranging from 160 MWa to 840 MWa by 2011. Under ML or MH load growth levels, cogeneration can contribute up to 300 MWa toward future requirements by the late 1990s. Most of the integration model sensitivity runs show cogeneration coming on line in 1994 and 1995. PacifiCorp currently has contracts with three industrial customers giving the Company options to participate in and determine the timing of cogeneration developments. Before large-scale acquisition can begin, contractual arrangements must be developed so the Company can participate in the development of cogeneration in a way that benefits the industrial customer, all other customers, and the Company itself. PacifiCorp has held discussions with these industrial customers, and maintains ongoing communication with them to assess the potential for development of this resource.

8. Identify at least one potential pumped storage site and determine the feasibility and cost effectiveness of the technology.

Pumped storage is a peaking approach which can add significant flexibility to a system which has low cost, off-peak resources available. Pumped storage, if ideally located, could enhance the cost effectiveness of the Company's existing thermal resources by providing a use for generation during hours when there would otherwise be less need to run the plants. This would result in more even and constant usage of the thermal plants, increasing their efficiency and decreasing their deterioration.

9. Identify where transmission upgrades could enhance resources and proceed where such upgrades are cost-effective.

The dispersed nature of PacifiCorp's system requires that transmission constraints be considered in all resource decisions. The modeling tools available analyzed resource needs on a system basis, rather than on a locational basis. Improved planning would result if resource needs could also be evaluated in terms of the transmission paths available between key customer areas and resource locations.

Because the Company is faced with some transmission limitations, there may be locations where load can be met more cost effectively by the addition of transmission capability rather than generation resources. Those locations need to be identified, and the costs estimated as accurately as possible. RAMPP-3 will include more explicit consideration of the entire transmission system. The Company is now investigating its short- and long-term transmission capability and requirements. During the RAMPP-3 planning cycle, it will be able to use information provided by a long-term transmission plan. That plan will address PacifiCorp's current energy options and the resource picture as it may be affected by any merger/acquisition activity by then. The plan will also enable the Company to better evaluate the appropriate geographic locations for specific resources.

10. Explore new or expanded modeling solutions for RAMPP-3.

PacifiCorp began looking for a more detailed operations simulation model after the consummation of the PP&L - UP&L merger. The Company reviewed several commercial models that used either hourly chronological or probabilistic load duration methods. Although most of these models were strong in representing capacity needs in resource dispatch, none treated transmission limits in a sufficiently rigorous manner.

Since the Company was unable to find an adequate commercial model, it looked for a vendor who was willing and able to modify their product. The Simulation Group (TSG), developer and marketer of PROSYM was selected. PROSYM is a derivative of POWERSYM, a chronological hourly production costing model developed at the Tennessee Valley Authority. PacifiCorp worked with TSG to enhance PROSYM to perform a reasonable multi-area simulation and to model discretionary wholesale sales. TSG made these changes to PROSYM and markets the resulting model under the name MULTISYM.

The Company has been working with MULTISYM for almost 2 years, developing and refining the representation of its system, testing the model logic, and enhancing output capabilities. The model, when fully tested, will be used in conjunction with existing power cost models. Because the model requires significant time to execute, it will be used primarily for short-term analysis of operational issues.

MULTISYM will likely be used along with a resource selection model in RAMPP-3, to provide production costing that reasonably reflects the complex PacifiCorp system. The Company's search for a suitable resource selection model will begin immediately upon the issuance of this Report.

11. Continue to implement system efficiency improvements as identified in RAMPP-1 and included in the existing system for RAMPP-2.

Efficiency improvements have been identified for the thermal plants, hydro plants, transmission, and distribution systems. Some have already been implemented, and others identified for the duration of the planning horizon.

DEMAND SIDE RESOURCE ACQUISITION ACTION STEPS

New Residential Buildings

The Company's objective with new residential buildings is to continue to capture more lost opportunities and begin acquiring cost-effective conservation beyond codes.

PacifiCorp will work toward improved building codes as the preferred way to capture savings in new residential construction. It will use the Super Good Cents program to improve builders' familiarity with efficient building practices; overcome resistance to codes; and work with state and local governments to improve enforcement of existing codes. The Company will use its program for capturing energy efficiency from manufactured homes as a model for effective incentives at the manufacturer level. It will also demonstrate efficient appliances to builders. The Company will:

- **Expand the Super Good Cents program to all states.** Achieve the following participation rates:

	1992	1993
MT	25	40
UT, WY	10	25

- **Extend the Long-Term Super Good Cents program to Oregon, Washington, Idaho and California, and include efficient appliances in the program.** Achieve the following participation rates:

	1992	1993
OR, WA, ID	15%	25%
CA	10	20

- **Achieve more than 85 percent penetration of efficient mobile homes in the Northwest market by 1994.** Support a regional program to encourage manufacturers to produce energy efficient mobile homes, and extend the program to Utah, Wyoming, and California. Support strong HUD standards.

- **Support incorporation of Model Conservation Standards into local codes in Idaho and Montana.**

- **Study effectiveness of code enforcement efforts in Northwest.** Work with Utah agencies to assure implementation of efficiency measures in new building code enforcement.

- **Incorporate solar access, solar water heating and passive cooling site design into the Super Good Cents program.**

- **Evaluate savings potential from new efficient appliances, such as ventilation heat pump water heater.**

Residential Retrofits

The Company plans to continue to develop the capability to acquire residential conservation while minimizing impact on non-participants. It will use current programs and pilot demonstrations to build capability. The action steps are to:

- **Develop and test a retrofit weatherization program in Washington. Operate a weatherization program there that achieves 3,000 audits and 1,500 weatherizations per year.** This program will verify that the activity levels assumed in future plans are achievable. Verify that customers can be persuaded to participate in the numbers anticipated. Investigate alternative approaches, such as competitive bidding.

- **Operate a weatherization program that offers enhanced audits and instant measures as a means of increasing customer acceptance of full weatherization.** Achieve the following numbers of full weatherization participants per year:

	1992	1993
OR		1300
CA	150	250
WA	933	1552
UT		300

- **Test a pilot program for pay-for-performance bidding for low-income weatherization in Oregon.** Examine whether bidding has advantages for program operation. Achieve full weatherization of 2,000 homes by the end of 1994.

- **Demonstrate feasibility of using Energy Service charge to operate residential programs while minimizing the impact on non-participants.**

- **Incorporate recently discovered means of achieving potential savings, such as from recovery of heating duct losses, into the weatherization program.** Demonstrate a methodology to accurately estimate and measure savings for purposes of quality control, cost assignment and documentation of program benefits.

- **Achieve proportional participation by low-income customers in residential weatherization.** Support full weatherization of 2,900 homes through community energy groups.

Residential Appliances

The Company wants to encourage a transformation of the market toward more efficient appliances. It will provide a market for high-efficiency water heaters and refrigerators through joint purchase programs with other utilities. The action steps:

- **Rely on improved standards as the preferred way to achieve savings.** Participate in joint projects with other utilities. Investigate manufacturer incentives like that used in "Golden Carrot" for future upgrading of appliance efficiency.

- **Upgrade efficiency of water heaters installed under the Hassle Free water heater program, and install 8,000 high-efficiency water heaters through the program.** Include installation of low-flow shower heads in all installations.

- **Join a national utility program providing incentives to manufacturers to produce super-efficiency refrigerators.** Participate in "Golden Carrot" award for efficient refrigerators to the extent that it is cost-effective for the Company.

- **Continue support for Northwest Regional Appliance Efficiency Group.** Seek market transformation toward leading-edge energy efficiency technology through joint utility programs that encourage customers to purchase more efficient models.

- **Continue to participate in BPA's Blue Clue program encouraging high-efficiency appliances.**

- **Evaluate customer preferences and available products for alternative cooling appliances in Utah.** The purpose is to determine which evaporative cooling products will receive customer acceptance as potential replacements for air conditioning.

Existing Commercial Buildings

PacifiCorp will continue to develop capability to acquire DSRs in small and large commercial buildings. It will also develop effective auditing and quality control. The action steps:

- **Pilot a program to retrofit 10 to 25 large commercial buildings in Salt Lake City and Portland.** Achieve a savings of 2.0 MWa by 1994.

- **Expand Pacific Environments program from Albany to include small businesses in Corvallis, Oregon.** Develop marketing techniques to persuade existing customers to pursue retrofits.

- **Focus on limited geographic areas to ease program development.** Develop management tools to effectively implement and manage large commercial programs. Verify appeal of programs to the market.

- **Improve ability to effectively market program to small businesses.** Operate pilot in Oregon. Achieve savings of 0.4 MWa by 1994.

- **Develop "standard package" offers for small businesses to minimize the costs of operating the program.**

- **Demonstrate the degree to which the Energy Service charge can reduce the impact on non-participants.**

- **Develop a way to commission buildings and verify that energy conservation measures are working.**

- **Demonstrate a methodology to accurately estimate and measure savings for purposes of quality control, cost assignment and documentation of program benefits.**

Commercial New Construction

The company's objective is to capture more lost opportunities in commercial construction. The action steps:

- **Expand program to capture lost opportunities as soon as possible.** Target most important segments for immediate attention. Review results to ensure that Company is on track to achieving 85 percent penetration by 1995.

- **Operate Energy FinAnswer in all states by 1993. Achieve the following participation rates in new construction:**

	1992	1993
OR	35%	45%
UT, CA, WA, ID	22	35
MT, WY		20

Develop simplified approach to increased efficiency for small businesses. Improve technical ability to verify installations and savings estimates. Revise program to incorporate lessons learned for future marketing.

- **Develop "standard package" offers for small businesses to minimize program operation cost.**

- **Develop methodology to commission buildings and verify that energy conservation measures are working.**

- **Demonstrate the degree to which energy service charge can reduce the impact on non-participants.**

- **Demonstrate a methodology to accurately estimate savings for purposes of quality control, cost assignment and documentation of program benefits.**

Industrial Sector

PacifiCorp will continue to develop its ability to acquire industrial DSRs. It will gain experience in implementing energy-efficient industrial technology; demonstrate the feasibility of efficient industrial processes; and develop a program that provides maximum value to participants with minimal impact on non-participants. The Company will also capture lost opportunities associated with new construction as they occur. The action steps:

- **Develop high market penetration for targeted high potential niches.** Identify key market segments for saturation ("blitz") marketing. Expand program offerings from successful segments to other opportunities.

- **Achieve 4.6 MWa of efficiency savings from the industrial sector.** Identify key market segments for saturation marketing. Expand program offerings from successful segments.

- **Develop Energy Partners program in all states.** Achieve the following participation per year:

	1992	1993
OR	1.1 MWa	0.9 MWa
CA	.2	.2
WA	.3	.5
UT	.7	1.1
WY	--	2.2
Total	2.3 MWa	5.0 MWa

- **Continue development of an industrial sector database to improve assessments of resource cost and availability.**

- **Demonstrate feasibility of using the Energy Service charge to distribute efficiency benefits to all customers.** Provide opportunities for participants to benefit from up front financing in exchange for sharing savings with other customers.

- **Develop programs across specific segments of industrial customers, offering technologies such as efficient air compressors, ammonia refrigeration or efficient motors.**

- **Develop pilot irrigation program in California.** Achieve a savings of 1,500 MWH by 1994.

QUESTIONS AND ANSWERS

This chapter is intended to focus on questions of a technical nature, or those that are of interest to a limited audience. The following topics are discussed:

- **Calculation of avoided costs**
- **PacifiCorp's bidding plans**
- **Economic development activities**
- **Lost opportunity purchases and acquisitions**
- **Discount rates**
- **The cost-effectiveness of conservation**
- **Clean Air Act of 1990**
- **Designing rates to acquire demand-side resources**
- **Impact of external costs on rate design**
- **Decoupling**
- **Evaluation of fuel switching**

1. How will avoided costs be calculated using information from the integrated resource plan?

One of the objectives of RAMPP is to provide information and guidance for calculating avoided costs and conducting competitive bidding. The load growth forecast used to calculate avoided costs will be between the RAMPP-2 ML and MH forecasts.

To calculate the short-term avoided costs (before resources are deficient), two studies using a production cost model are performed on a monthly basis. The models use forecasted power costs and 50 years of water year data weighted by 107 years of stream flow data. The only difference between the two studies is that one adds an increment to the system resources available each month. The increment serves as a proxy for generation from qualifying facilities. The differences in system production costs between the two studies represent the Company's short-term avoided costs.

To calculate avoided costs after resource deficiency, the Company compares the costs of resource expansion plans for the avoided cost base case to resource expansion plans for a case with less resource need. Both expansion plans will be developed from the same portfolio of resources, using the same selection techniques used to develop the illustrative plans for the RAMPP-2 forecasts.

2. How will competitive bidding be used to implement RAMPP-2?

Competitive bidding is a resource acquisition process that should be undertaken only after PacifiCorp has a relatively clear view of its requirements for new resources for the next five to 10 years. The Company's integrated resource planning process helps determine when to develop new resources and the most efficient mix of resources that may be acquired through competitive bidding.

Through competitive bidding, utilities can test and assess the competitive marketplace for power supply and can potentially acquire some of the low-cost electricity resources that have been identified and evaluated through least cost planning. Competitive bidding can pose some risks for a utility that operates in a number of jurisdictions where the state commissions do not agree on a general process for bidding. The risks to both customers and shareholders increase if state commissions implement competitive bidding rules that vary substantially from jurisdiction to jurisdiction. Conflicting rules could lead to a situation in which a competitive bidding process must violate the rules of one state to comply with the rules of another, resulting in extended litigation.

PacifiCorp released a Request for Proposals (RFP) on October 1, 1991. The RFP is for a total of 50 MWa of long-term resources that produce electricity or savings of electricity for at least 10 years but not more than 20 years. All bids were due by February 28, 1992 and a short list was selected on April 24, 1992. While the RFP is not included in RAMPP-2 resource alternatives, if resources offered in response to the RFP are more cost effective than resources identified in the plan, they will be developed first.

PacifiCorp plans to file a request for proposals every two years; however, it is anticipated that the timing of the next RFP will be more closely aligned with the completion of RAMPP-3. The timing of the Company's first RFP occurred before RAMPP-2 to avoid delay in beginning the bidding process. The timing of the next RFP will occur after resource needs are evaluated in RAMPP-3. Once RAMPP-3 is completed, the Company anticipates issuing an RFP for some block of resources identified in RAMPP-3.

The 1991 request for proposals marks the first time PacifiCorp has used an RFP in resource acquisition. Both demand side and supply side bids are being solicited. Supply side resource proposals must be for a project of not less than 100 kW. They are requested system wide and are limited to qualifying facilities and independent power producers. Any supply side bidding needs to be done on a system wide basis, since that is how Company resources are planned. DSR proposals must provide for a minimum of 250,000 kWh of savings per calendar year and are requested in the states of Utah and Washington. Significant jurisdictional issues exist for DSRs, so that demand side bidding must be done separately for each jurisdiction.

For planning purposes, the example DSR programs are utility operated programs. This does not eliminate the possible use of energy efficiency services from outside contractors. In fact, the programs are expected to be operated mainly through contractors. Within a given demand side program, efficient management will include competitive bidding among contractors to control costs and develop the infrastructure. Another possible approach is for the Company to use demand side bidding to offer to pay for energy savings that are achieved. PacifiCorp is currently experimenting with demand side bidding in specific areas. Based on those results, the Company will develop other bid offers. In general, the Company expects to use bidding to fill in market niches where utility programs are not as effective at achieving participation.

3. How does the Company's assessment of the costs and benefits of economic development activities relate to RAMPP?

Economic development, whether it is assisting existing businesses and industries, attracting new ones, or working with local communities in their development efforts, is an important part of PacifiCorp's overall service commitment because it benefits customers, the Company, and the communities served by PacifiCorp.

The Company works in partnership with local communities, states and other interests, to support the development and implementation of plans, strategies and programs to expand and diversify the overall economic base. The Company's three-pronged approach to economic development is to: 1) work with individual communities to help them achieve the growth they want; 2) work with existing businesses to help them succeed and expand; and 3) help businesses locate new facilities and jobs in the Company's service area.

The Company's economic development activities produce both quantifiable and non-quantifiable benefits. The tangible benefits to the Company consist primarily of direct and indirect electric revenues which help keep prices stable for all customers. The less tangible benefits are those associated with establishing a broad and more diversified economic base in the Company's service area.

Local communities, as well as the customers within those communities, benefit from economic development in a number of ways. Diversified economies are more resilient to the dislocation and social costs that can result from cutbacks or shutdowns of major employers in the community. There is no question that the economy and quality of life in a community are adversely impacted when major employers or industries downsize or curtail operations. This is precisely what occurred in Utah in the 1980s with Geneva Steel and Kennecott and throughout the Northwest in the 1990s in timber dependent communities. By expanding and diversifying the economies of local communities, the existing work force is used, employment opportunities increase, household income increases, and the local tax base is expanded.

Economic development is one of the Company's activities that, when working with various resource acquisition strategies, can help the Company keep price increases at or below the level of inflation. PacifiCorp's load forecasts reflect the combined effects of general economic conditions and the Company's activities. The impact of economic development on retail prices is incorporated in the Major Issues chapter of this report under the section on Growth and Price Stability.

4. What standards will the Company use to evaluate "lost opportunity" purchased power and acquisitions? How does the concept of lost opportunity relate to merger and acquisition activity?

The resource acquisition strategy of the Company is multi-faceted. The Company intends to acquire cost effective resources from a variety of sources that will both complement and enhance the Company's existing power supply system. This strategy includes acquisition of energy efficiency resources through demand side programs; resources from IPPs, QFs and others through the bidding program; Company-owned resources through construction, such as combustion turbines and renewables, conventional and non-conventional arrangements with other utilities; and existing low cost resources available for a limited time, as with resources available due to the bankruptcy of Colorado-Ute.

PacifiCorp considers several general criteria in determining reasonable costs for purchased power and acquisitions. The resource should be needed to meet anticipated loads; provide flexibility, reliability and a good fit with the operation of the existing system; and be cost-effective relative to other resources available in the RAMPP portfolio and to long-term avoided costs. The Company also considers the short-term and long-term effects on customer prices, and the short-term and long-term effects on Company earnings. And, the Company evaluates whether the resources would have been a "lost opportunity" (an opportunity available only for a limited time).

The Company looks for the following type of benefits from any resource acquisition:

- Is the resource a stable, low cost generating asset?
- What access is available to additional low-cost surplus generation?
- Are there opportunities for seasonal capacity exchanges?
- Are transmission arrangements available?
- Can arrangements be structured to provide future generation and transmission benefits?

In analyzing any asset acquisition or generation purchase, the Company considers how the load served by that resource complements the PacifiCorp system; any transmission which would benefit retail customers; the energy storage capabilities of the resource; its environmental characteristics and the risks posed by its current emissions; its potential for contributing to lower costs for the entire system; its potential to be a productive capital addition; whether it provides assets that can be fully added to rate base; and the likelihood of it being approved in a timely fashion.

The concept of lost opportunity can be applied to any resource alternative. The notion of lost opportunity reflects the timing of a resource acquisition being somewhat in advance of expected need. Nevertheless, resources acquired ahead of need must still be cost effective in the long run. Lost opportunity can be applied to the DSR area. For example, new construction provides an opportunity to influence design and construction standards of buildings. If the Company does not intervene during construction, that opportunity to acquire cost effective resources from current construction is lost. Certain renewable projects and purchases may only be available for a limited time at a favorable cost.

Lost opportunity can also be applied to supply side resources. There can be limited windows of opportunity for acquiring existing generation facilities. For example, if the Company had not entered into the Colorado-Ute transactions during the bankruptcy proceeding, it would have missed the opportunity to participate.

PacifiCorp is continuing to look for similar windows of opportunity. The Company believes that because of the continued surplus of resources in certain areas, a limited window of opportunity exists for the Company to acquire resources at favorable costs. PacifiCorp has identified several "windows of opportunity" to acquire existing, low-cost assets from other utilities. The identified surplus capability is located in areas which have:

- A predominance of thermal generation,
- Reduced load growth,
- Capacity additions which came on line ahead of need, and
- Large seasonal load differences.

However, the Company will not rely on lost opportunity resource acquisitions as its sole resource strategy; rather, it will use such acquisitions to complement the flexible and diverse acquisition strategies described in RAMPP-2.

RAMPP-1 identified a significant amount of resources available from the marketplace. PacifiCorp believes it can meet its pricing goal while concurrently enhancing its earnings base by acquiring the actual generating assets while prices are low, as opposed to buying the power on a wholesale basis. The same assumptions and information are used to conduct the evaluation of acquisitions as are used in the analyses for RAMPP-2.

It is clear from past experience that resource acquisition opportunities rarely involve a simple numerical comparison of one resource to another (i.e., coal versus gas versus conservation). Instead, such opportunities represent a chance to achieve, through innovative arrangements, potential benefit from the diverse load and resource characteristics within the region and with other regions.

PacifiCorp's recent agreements with APS and Colorado-Ute demonstrate such opportunities for acquisition. Further, one of the key benefits of the Utah Power/Pacific Power merger, as confirmed by the analysis that led to RAMPP-1, was that it uniquely positioned the Company to pursue potential resource acquisitions and take advantage of regional diversities.

Mergers and acquisitions of existing generation help the Company grow by providing proven, low-cost resources. These opportunities complement the company's existing power supply resources. They provide low-cost power for customers and improve access to wholesale markets. Both the APS and Colorado-Ute transactions involve acquiring coal-fired power plants that, compared to other resource options, are very economical. They also create new opportunities for innovative arrangements, e.g. wholesale exchanges, increased operating efficiencies, and new customers, which helps to spread fixed costs. These assets allow the Company time to pursue the best of the RAMPP-2 options. They also protect shareholders and customers against the risk that emerging technologies could render new, longer-lived central station power plants and systems obsolete.

PacifiCorp will continue to pursue opportunities to acquire existing low-cost assets and other arrangements with other utilities. These include generation and transmission assets, negotiated rights to future generation, seasonal exchanges, and future access to retail and wholesale customers.

The RAMPP-2 analysis did not include a hypothetical merger candidate in its portfolio of resources. A hypothetical analysis is unlikely to be representative of an actual situation, and may speculate on specific details which would be either premature or inappropriate. Each opportunity is unique, and is evaluated based on criteria discussed above, including the multi-faceted benefits it could bring to the Company and its customers. The publicly-filed testimony and analysis available from the Utah/Pacific merger can provide readers who wish more information significant insight into the kinds of merger benefits that can be achieved through mergers and acquisitions.

5. Has PacifiCorp evaluated the impact of different discount rate levels, and if so, what is the result of that evaluation?

Discount rates are used in RAMPP to consistently evaluate the costs of resources that come on line at different times and have different lifetimes. For each new resource alternative, there is an associated stream of annual costs. A discount rate is applied to these streams of annual costs to calculate a present value in a standard year, thus allowing a comparison to be made of the costs of the alternative resources.

The effects of three discount rate levels on the resource portfolio were tested. Those discount rate levels were 8.2 percent, 9.54 percent and 10.9 percent. The 9.54 percent level is the Company's marginal after-tax cost of capital. The 8.2 percent level is based on a 3.0 percent social discount rate as used by the Northwest Power Planning Council. The 10.9 percent reflects the difference between the 8.2 and the 9.54 added to the 9.54, for symmetry. The three levels had very little impact on the resource costs, and did not change the ranking of any resources. Therefore, the Company's marginal after-tax cost of capital was used for all of the analyses shown in RAMPP-2.

Graphs showing the impact of different discount rate levels on resource costs are available in the Supply Side Technical Appendix.

6. How will the RAMPP-2 results be used to calculate a new level of conservation cost effectiveness?

The avoided costs derived from RAMPP-2 will provide the basis for generation costs used in determining what level of conservation is cost effective. Included in generation energy costs will be the estimated value of the nonfirm wholesale market opportunities available to the Company.

After avoided costs are calculated, a worksheet is prepared which adds the components that adjust the avoided costs for conservation cost effectiveness. Those components are the 10 percent regional conservation advantage (from the Regional Act), line losses, and transmission and distribution savings. The cost effectiveness limit determines which DSRs are too expensive. However, individual programs, when they are proposed to the Commissions, may include measures which exceed the cost-effectiveness limit. This could be to ensure a particular program is consistent with other regional efforts, or to include measures which would increase customer participation.

7. What other sources besides RAMPP-2 are used to determine the appropriate levels of conservation cost effectiveness?

PacifiCorp has relied on recent marginal cost analyses, as well as avoided cost results, to calculate the appropriate level of conservation cost effectiveness. For example, the transmission capacity costs included in conservation cost effectiveness are based on the Company's forecast of the cost of meeting increased load on its transmission system. These costs are derived from the Company's most recent marginal cost analysis. Transmission capacity costs are not included until 1996 because the decremental load placed on these facilities as a result of conservation is not enough to cause a change in investment for several years.

In determining appropriate distribution costs to include in conservation cost effectiveness levels, only the transformer portion of distribution capacity costs are considered because, unlike most distribution costs, the size of the transformer varies depending on the load placed upon it. It is conceivable that DSR could defer the incremental transformer capacity costs associated with increasing load. Therefore, the marginal cost of the transformer portion of distribution capacity costs is included beginning in 1996. The fixed, or commitment-related transformer costs would not vary since DSR would have no effect on the fact that every customer must have access to a transformer. In addition, distribution commitment-related costs such as meters and service drops would not be avoided as a result of DSR.

The question of whether other distribution capacity costs would be avoidable as a result of DSR was also analyzed. The demand portion of the backbone distribution facilities (substations, poles and conductors) exists to serve the combination of all customer loads occurring on the feeder. It is doubtful that this part of the system would change in response to a reduction in load. In addition, since backbone distribution facilities are built to serve both participants and non-participants, the impact of demand side programs would be very diluted. Due to these reasons and the fact that it would be very difficult to model the effects, if any, of load reduction by demand side programs on this part of the system, these costs were not included in arriving at conservation cost effectiveness values.

The conservation load factor is used to convert marginal capacity costs from dollars per kW to mills per kWh. It is based on the relationship between the DSR energy savings to the DSR capacity savings. The estimated conservation load factor varies by customer class.

The Company's most recent line loss study, dated May, 1991, resulted in a 10.5 percent estimate of system wide secondary sales losses. That estimate is used to adjust energy costs for conservation cost effectiveness.

8. How will the Clean Air Act of 1990 affect PacifiCorp?

The 1990 Clean Air Act will have two major effects on the external costs considered in resource evaluation. First, some costs that formerly were external will become internal. Second, a great deal of additional information will be generated which will improve utility and regulatory estimates of those external costs.

The act calls for major reductions in both sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions. SO2 is to be reduced through a permanent cap on emissions and a system of tradeable emission allowances. NOx will be reduced by an allowable emissions rate based on type of boiler.

PacifiCorp has 23 coal-fired units, about half of which are equipped with scrubbers to reduce SO2 emissions. The PacifiCorp plants most affected by the Clean Air Act are the Centralia plant in Washington and Naughton Units 1 and 2 in Wyoming. The Company is studying how to cost effectively bring these plants into compliance. Several PacifiCorp units may also be affected by provisions in the Clean Air Act relating to NOx.

Analysis of the requirements of the 1990 Clean Air Act Amendments indicates that some equipment and operations modifications will likely be required at most of PacifiCorp's coal-fired electric generating units to bring them into compliance with the sulfur dioxide, nitrogen oxide, and continuous emission monitoring provisions of the Act. Each of PacifiCorp's units must meet certain emission limitations by January 1, 2000, and have continuous emissions monitoring equipment (CEMS) installed and operating by January 1, 1995.

It is currently estimated that the capital cost of the CEMs will be between $2.0-2.5 million; operating costs will be approximately $40,000 per year. PacifiCorp units must also comply with nitrogen oxide emission (NOx) limitations where tangentially-fired boilers must meet 0.45 lb/mmbtu and wall-fired units must meet 0.50 lb/mmbtu based on low-NOx burner technology. Most units do not presently have specific equipment to control NOx emissions, and the nature of such emissions from PacifiCorp units is currently being analyzed. However, the capital costs of boiler upgrades are estimated at $20 to 40 million. Operating costs will increase nominally due to combustion efficiency losses.

Compliance costs associated with the Phase II (i.e. year 2000) SO2 provisions of the Amendments can be estimated after a definite compliance strategy is selected for those PacifiCorp units needing to take compliance actions. The selected strategy could include reducing emissions through sulfur dioxide allowance trading, possible process modifications, and/or fuel management strategies.

9. What is the appropriate role for price design in the acquisition of demand side resources?

PacifiCorp believes that the cost of providing service is an important element in the pricing of electricity, along with fairness, meeting customers' needs, customer impacts, ease of understanding and administration, relationship to competitive alternatives, and avoidance of undue discrimination. The decision to use energy is closely related to the decision to conserve. Through these decisions, the customer can and should apply energy to high value applications and limit energy directed to low value uses. Appropriately designed prices should help the customer to make wise decisions for both kinds of uses.

The Company believes that integrated resource planning is not the appropriate forum for considering specific rate design changes. Rate design is determined by the Company and each state's regulatory authority. Evaluation of the Company's pricing structures should be considered as an implementation of the results of the RAMPP planning process. It would be very difficult for the Company to assure that it could achieve significant rate design changes. Therefore, it would not be appropriate to use possible consumption changes from rate design changes as a "resource" in RAMPP.

Additionally, designing prices to affect demand side activity would require the use of elasticity estimates. The only estimates the Company has are those used in the load forecasting model. Those elasticity estimates, while reliable and appropriate in their intended applications, are not appropriate for the design of prices. First, the forecasts are developed using "frozen technology" models. The elasticities address only the fuel choices consumers will make as energy price changes, and are therefore referred to as cross-elasticities. They do not address how consumers' use of an appliance will be altered as prices change. The cross-elasticity measures are not appropriate when designing prices, since prices can affect appliance choice and use, as well as fuel choice. Second, the cross elasticities used in the forecasting models reflect expected behaviors of entire customer classes. Elasticities used in price design would need to be developed for each tariff. Finally, elasticities employed for price design would have to be very precise. While some ambiguity in elasticities is acceptable when dealing with forecasts where there are many factors that could affect the outcome, we believe that precise elasticities would be necessary for price design.

10. How should external costs be reflected in retail prices?

The Company believes that its prices should reflect the costs incurred by the Company in the production and delivery of products and services. External costs play a role in those functions, and are legitimately included to the extent that they affect costs. For example, the incorporation of externalities into the Company's planning and resource selection procedures may well alter the order in which resources are selected, with impacts on overall and marginal costs. These impacts should be incorporated into the Company's revenue requirement and price design.

11. Would a mechanism to decouple sales from profits help PacifiCorp acquire the demand side resources in its integrated resource plan?

No. The Company believes that direct economic incentives can be developed to assure the acquisition of all cost effective DSRs. Investment in DSRs is profitable for the Company, given revenue neutrality and simple modifications to existing accounting treatment so that the Company has an opportunity to earn a utility rate of return on DSR investment. Once properly addressed within the existing framework, investments in DSRs provide the Company with a way to achieve growth in the business and provide both customer and shareholder value.

In such an environment, decoupling will not encourage additional demand side investment. As evidence, the Company recently announced its commitment to acquire 170 MWa of DSRs by the end of 1996 -- requiring an investment of nearly a half billion dollars. This will allow the Company to acquire its share of the NWPPC Regional Conservation Goal. And, it will put PacifiCorp among the leaders in DSR acquisition as measured by percent of revenue devoted to such acquisition -- over 6 percent of revenues in 1996. For PacifiCorp, the decision to undertake this effort was based on the cost effectiveness of these resources and the assumption that the Company would have an opportunity to earn its allowed rate of return on such investments.

Some proponents of decoupling believe that it removes the utility incentive to pursue additional sales. The Company believes that sales which result from energy efficient applications provide benefits to customers and society, and should not be discouraged.

PacifiCorp believes its customers are better off if they are aware of all their options so they can make the best energy choices for themselves. The Company provides the best service to its customers by conveying a consistent message to employees. That message is that employees are there to help customers make smart and sound energy decisions. A sound energy decision for a customer would be to improve the efficiency of his or her electric end uses, or to adopt new electrotechnologies which could make those uses more energy efficient and productive.

Decoupling is a very limited mechanism which addresses only short term adjustments between rate cases. Promoting energy efficient technologies enhances the long run viability of the Company's business and provides long run customer benefits. Decoupling mechanisms would not have an impact on the Company's promotion of energy efficient uses.

PacifiCorp believes there are a number of potential disadvantages with current decoupling proposals as adopted by several utilities. These include:

1) To a significant extent, decoupling effectively guarantees that utilities will earn their allowed revenue through price adjustments.

2) Decoupling creates a market distortion by insulating utilities from real marketplace forces that other businesses must face.

3) Decoupling can reduce the amount and vigor of competition to meet the needs of citizens.

4) Mechanisms to achieve decoupling can be complex for customers, regulators and utilities to understand.

In summary, while the Company recognizes that some form of alternative regulation may eventually be developed that effectively deals with these concerns, it cannot support PacifiCorp adopting any of the decoupling systems other utilities have put in place.

12. Has PacifiCorp evaluated fuel switching as a demand side opportunity, and if so, what is the result of that evaluation?

Some parties have suggested that residential customers of electric utilities should switch from electricity to natural gas for their space and water heating. The rationale is that such switching would lessen the need for expensive new electricity generating resources and reduce the use of fossil fuels, which have been linked to global warming and acid rain.

PacifiCorp believes that public policy should encourage the efficient use of all fuels, rather than promoting one fuel over another. No public policy should encourage the increased use of a nonrenewable finite fuel without regard to end use efficiency. Shifting consumption toward gas may result in uses which are less efficient than they could be if competition with electricity provided motivation for technological advancement. Regulatory mandates that encourage fuel switching tend to restrict competition, which then slows the development of new energy efficient technologies and products.

Electricity should be encouraged for some end uses because of its efficiency, though not for others. The real issue is how to help consumers make wiser energy decisions.

PacifiCorp believes that customers will be able to make wiser choices if the various energy providers are encouraged to compete with one another. In fact, this has been the experience where competition has occurred. A good example is with the development of energy efficient heat pumps, which was met by the development of high efficiency gas systems and gas heat pumps.

PacifiCorp recognizes that customers have fuel alternatives. It takes that fact into account in making its demand forecasts -- not in its evaluation of resource alternatives. Gas is a more efficient fuel in some applications, but not in others. This is true even for specific markets such as space heating, because the form of end use affects efficiency. For example, if resistance heating is used to heat one room, it can be considerably more efficient than a whole-house gas system.

As a result of the Oregon Public Utility Commission's proceeding on fuel switching, PacifiCorp evaluated customers' use of natural gas as a potential resource. Fuel switching is deliberate load shedding, not conservation. The analysis compared the life-cycle cost of the fuel switch using the avoided costs of gas vs. electricity. The marginal costs associated with transmission and distribution were included in calculating the avoided costs but the 10 percent cost advantage for conservation was not included. For most of the cases examined, fuel switching was not a cost effective option. The savings gained from typical consumption were not sufficient to justify the cost of changing the equipment. There are exceptional cases of high consumption where fuel switching might be more beneficial. However, the analysis did not show that sufficient resource could be gained to justify fuel switching as a resource acquisition program.

CONCLUSION

This RAMPP-2 Report represents a working document and a dynamic process which will be used to guide PacifiCorp's resource and marketing decisions for the next two years. The primary value in producing 20-year plans is twofold: to provide a long-term context for developing an action plan for utility activities in the next two years with an understanding of the long term implications of those actions; and to provide an overall perspective and consistent planning framework for making resource and market decisions over those two years. The Company uses the RAMPP process to make decisions rather than rigidly adhering to a specific plan. In this way, the Company retains the flexibility it needs to respond to changing conditions.

PacifiCorp's approach to managing power supply and demand will continue to reflect a priority on the following eight key principles. The Company uses these eight principles to evaluate resources, and to develop and evaluate resource plans. There is no one best resource plan. The best approach at any time depends on how resource alternatives and Company objectives can be balanced to meet system needs.

1. **Minimizing cost and retail price impact:** The Company's strategic goals include keeping retail prices and customer costs as low as possible to remain competitive in the energy marketplace.

2. **Reliable service:** All resource choices should be evaluated on their ability to enhance the Company's ability to provide reliable service to customers.

3. **Efficiency:** This includes enhancing the efficient operation of the Company's existing system, identifying beneficial arrangements with other resource providers to sell, purchase or exchange power, and helping customers use energy more efficiently.

4. **Environmental responsibility:** The Company will continue to improve its business operations to mitigate impacts on natural resources and the environment, and will continue to integrate into its resource planning a consideration of environmental impacts.

5. **Flexibility:** A variety of resource options will be employed as needed to respond to changing circumstances.

6. **Diversity:** The Company will maintain a broad variety of resource options to hedge the risks associated with an uncertain future.

7. **Dynamic balance:** The desired balance is an economically efficient margin of resources over loads.

8. **Innovation:** PacifiCorp is willing to take calculated risks and try new ideas to better meet customer and shareholder needs.

INTEGRATED RESOURCE PLANNING

The RAMPP process uses an approach called "integrated resource planning." It sets up a framework for the Company to consider both resource and market conditions in making decisions. Included in the RAMPP-2 report are all of the basic elements of integrated resource planning. The following section provides answers to some of the key questions related to the Company's approach to integrated or "least cost" resource planning:

1) The Company followed least cost principles in developing its plan.

Resources were selected based on their cost and on Company policy goals, such as an accelerated DSR program and renewable pilot projects. Basing resource selections partly on Company strategic goals means some of those resource choices will not be strictly "least cost." However, the Company's experience with those resources will provide valuable knowledge for making least cost decisions in the future.

2) The Company examined a range of forecasts and considered other important future uncertainties.

The fact that the future is uncertain was addressed through four forecasts, from a low of 0.5 percent to a high of 4 percent load growth over 20 years. In addition, four scenarios were examined which primarily introduced uncertainties on the resource side. Finally, a number of sensitivity studies were conducted, including five which examined the impact of external cost adders on resource planning, six which introduced uncertainties in the existing system and new resources, and seven load growth sensitivities that tested what would happen if actual load growth was different from the load growth assumed for planning.

3) The Company considered all feasible resource alternatives for balancing resource supply with electricity demand.

The demand side portfolio includes resources which are consistent with the DSRs that have been identified by other regional entities. The supply side portfolio included a variety of resources, such as contract rights, renewables, gas-fired, and coal-fired resources.

4) The Company assessed supply and demand alternatives in a consistent manner.

All demand and supply alternatives were evaluated using the real levelized cost of energy. DSRs were evaluated from a total resource cost perspective. The estimated costs for the identified DSR resources were below the costs of supply side resources, thus each of the illustrative plans shows DSRs being added first to meet resource needs.

5) The planning process described long-range plans for balancing supply and demand amid all the uncertainties, and a short-range action plan consistent with the long-range plans.

Long-run illustrative plans were developed for each of the forecasts, scenarios and sensitivities to balance supply and demand. A short-range action plan was derived from those illustrative plans, consisting of the actions needed in the next two years to be able to put those plans into action.

6) The Company evaluated possible external cost impacts as part of its evaluation of resource alternatives and considered those impacts in its resource plans.

Residual air emissions of four types were considered for each resource alternative, and again for the Company's power system as a whole after each illustrative plan was developed. External cost adders at four different levels were applied to the four air emissions to measure their effect on relative cost comparisons of resource alternatives. The external cost adders were also used to develop alternative illustrative plans for the MH forecast. And, they were used as adders to the internal costs of existing resources to test their impact on the dispatch of those existing resources. The Company accelerated plans to test and develop renewable resources, in recognition of their lower environmental impacts, as well as the need to confirm cost and performance assumptions.

7) The planning process included the results of substantial public involvement.

PacifiCorp held 11 meetings with its public advisory group, and additional subgroup meetings on specific topics. The advisory group provided valuable guidance and feedback which the Company used in refining its planning process. Additional information on the advisory group and the meetings is available in the Results Appendix.

MANAGING UNCERTAINTY

The RAMPP-2 analyses have demonstrated that effective resource choices can be made in spite of multiple uncertainties. The Company will face uncertainties in several areas.

Pricing

The Company's merger-related pricing commitments of "no price increases" will expire at the end of 1992, marking five years of price stability and, in some cases, price reductions. PacifiCorp has no immediate plans to increase its prices after 1992. The Company's current strategic goals call for holding retail prices to a level that, on average, does not increase as fast as the rate of inflation. The Company has identified a broad portfolio of resource options it can bring on line to provide electric service to customers at competitive prices.

RAMPP-2 indicates that load growth can occur, and new resources can be added to meet that need, without the Company having to request price increases greater than the level of inflation. Challenges to price stability could come from high load growth, high gas prices, and/or extreme actions to force emission reductions.

Environmental Impacts

Managing environmental impacts along with other key considerations is essential for sound resource planning. Emission levels for each of the illustrative plans indicates that significant gains in reducing emissions per kWh can be achieved under most load growth conditions (i.e., emissions grow at a much lower rate than total GWH requirements). The exception to that pattern is low load growth, where emissions grow at about the same rate as GWh requirements.

By linking the environmental goal with the RAMPP-2 planning process, the Company was able to test the planning prudence of the targets in that goal. The analyses indicate that the pilot renewable projects and the anticipated additions over the planning horizon will be appropriate unless gas prices increase significantly, the cost of renewables declines significantly, or national policy direction is developed regarding aggressive CO2 targets to avoid global climate change. The performance and costs of the pilot projects will determine whether the initial schedule for acquisition of renewable resources is maintained or adjusted.

The resource plans that minimize both system costs and emissions are very similar to MH4, especially for the next ten years. Therefore, the actions the Company anticipates over the next two years are consistent with both of those goals.

Load Growth

There are three ways in which future load is uncertain: 1) what the actual level of load growth will be, 2) whether it will be different than expected, and 3) whether it will change over the planning period. Although the actual level of future loads is uncertain, a portfolio of flexible resources allows the Company to adjust resource acquisitions and maintain a reasonable balance. If very low load growth occurs, the flexibility built into some of the resource options would allow the Company to maintain reasonable levels of resources and, because of the Company's access to other markets, sell any residual surplus that may exist. If load growth is very high, the Company's flexible resource portfolio contains sufficient resources that can be acquired on short notice to be able to obtain the resources needed to meet customers' needs. These short-notice resources include SCCTs and some renewable resources.

If future load growth is different than the level expected, costs are still manageable, and price increases remain below the level of inflation except in the case of high growth. If the level of load growth changes over the planning period, price increases can be kept below the level of inflation unless high growth occurs for a substantial period.

Due to any of these uncertainties, the Company could inadvertently over-build or under-build. The analyses indicate that there are not large cost impacts to some over- or under-building. The Company's broad access to power markets enables it to acquire secondary or long-term power to meet temporary shortages, and to sell any temporary surpluses. The revenues from these sales is credited back to benefit retail customers through lower prices.

Demand Side Resource Acquisition

The price impact on PacifiCorp's customers would be small if the level of DSR acquired is more or less than anticipated. If DSRs were being acquired in lesser or greater amounts than anticipated, the Company would have adequate lead time to determine how to adjust its programs and/or resource planning. The diverse portfolio and access to markets allows the Company to acquire power needed to meet system needs if DSR acquisitions do not occur as quickly as planned, and the Company can delay other commitments if DSR acquisitions occur more quickly than planned.

Fuel Prices

Fuel price uncertainty is reduced by the Company's long-term coal supplies and the abundance of low sulfur coal reserves close to our existing generating facilities. Natural gas prices, however, present greater risks. Gas-fired resources (cogeneration, SCCTs, and CCCTs) are a large component of the illustrative plans. The future price of gas will be critical in determining the actual timing and amount of gas-fired resources that are added to the system. If natural gas prices increase faster than anticipated, the Company will need to rely on more renewable resources. Coal gassification or other clean coal technologies may also provide an effective hedge against gas price escalation risks in the future.

Capacity and Energy Needs

It is uncertain now whether future resource needs may be driven more by peak or energy needs. The Company's strategy to quickly site SCCTs (to provide peaking), with sufficient land to be able to convert them later to CCCTs (to provide energy) can mitigate the potential costs to the system of this uncertainty. Plans to explore pumped storage also provide future flexibility to balance both capacity and energy needs.

Current Resource Performance

If existing resources are unable to perform as expected, the Company has enough flexibility and options to still meet customers' power needs at low cost. If hydro resources become less flexible, there would be retail price impacts, but prices would not need to increase faster than inflation. If the thermal plants perform at a lower capacity factor, the price impact could be greater than inflation, but it would still be less than the impact associated with high load growth. The Company's continuing efforts to maintain and increase plant efficiency is an important strategy to reduce future planning uncertainties.

WHERE DO WE GO FROM HERE?

Development of RAMPP-2 resulted in a new action plan for PacifiCorp for 1992 and 1993. That action plan calls for the Company to:

In the Areas of Demand Side Activities and Renewables:

- Continue to increase the amount of DSR acquisitions. Achieve 25 MWa of savings by the end of 1993, and take the necessary actions in the next two years to accelerate the ramping up of DSR programs so that the Company achieves 170 MWa by 1996.

- Determine actions needed in 1992 and 1993 to bring 125 MW of wind capacity (40 MW effective capacity) on line by 1996-97, and pursue those actions.

- Sign confidentiality agreements for one or more potential sites to analyze the feasibility of bringing 50 MW of geothermal capacity on line by 1998.

- Determine the cost and performance of utility-scale solar energy resources through participation in the Solar II demonstration project.

In the Area of Peaking Resources:

- Initiate siting, permitting, and procurement for up to 450 MW of simple cycle combustion turbines (SCCTs).

- Implement the decision to acquire 150 MW of peaking resources as part of the Company's agreements with Arizona Public Service Company.

- Identify at least one potential pumped storage site and determine the feasibility and cost effectiveness of that technology.

In the Area of Cogeneration:

- Sign intent agreements and pursue contract negotiations with industrial customers to bring up to 300 MWa of cogeneration on line by 1997.

In the Area of Efficiency Improvements:

- Identify where transmission upgrades could enhance resources and proceed where such upgrades are cost-effective.

- Continue to implement system efficiency improvements as identified in RAMPP-1 and included in RAMPP-2.

Getting Ready for RAMPP-3:

- Explore new or expanded modeling solutions for RAMPP-3.

No one knows what the future will bring. The actions identified in RAMPP-2 are designed to give PacifiCorp the flexibility it needs to be able to prudently and responsibly meet customers' electricity needs, regardless of how the future unfolds. RAMPP-2 is not a hard-and-fast blueprint for the future -- and therein lies its strength. It provides options and a diverse set of tools to be employed as needed depending on future circumstances.

The plan provides a guide for evaluating future opportunities, and making resource and market decisions over the next two years. The two-year action plan is a road map for actions the Company needs to take to prepare for the future. The overall plan will be revised in two years. At that time, an additional two years of information will be available. The result will be a new two-year action plan for 1994 and 1995.

GLOSSARY

20-year NPV Op. Rev.
20-year net present value of operating revenue. Can also be thought of as the 20-year net present value of the Company's revenue requirement.

AFB coal plants
Atmospheric fluidized-bed Coal Plants. see Atmospheric fluidized-bed combustion.

Annual cost ($/kW Yr)
As a result of levelization (see below) the capital cost of a resource is spread over several years, and the annual running cost is added to it.

APS
see Arizona Public Service.

Arizona Public Service
Arizona utility which recently completed an agreement with PacifiCorp involving the sale of Cholla unit 4, other generating rights, transmission rights, and a long term power transaction.

Atmospheric fluidized-bed combustion
Technology where coal is burned in an atmospheric pressure fluid-bed that is suspended by air blown in from below.

Average Megawatts (MWa)
A unit of electric consumption or production over a year. It is equivalent to the energy produced by the continuous use of one megawatt of capacity over a period of one year. It is equivalent to 8760 megawatt hours, or 8760,000 kilowatt hours.

Average water
The amount of hydro energy that would be available if the region experienced an average stream flow condition.

Avoided cost
The price at which qualifying facilities sell their power to utilities. Avoided cost is calculated by the utility based on resource additions as identified in their least cost plan.

Base unit cost
The average price to the retail customer.

Binary cycle plant
Geothermal plant that uses a secondary working fluid, which is vaporized by hot geothermal fluids, to drive a turbine generator.

Blue Clue program
BPA's residential sector demand-side program which recognizes distributors for selling high-efficiency appliances.

Bottlenecks
Transportation design anomaly where insufficient capacity is available for the level of power needed to be transported.

BPA
Bonneville Power Administration. The federal agency which markets power from federal hydro dams in the Northwest.

BTU
British Thermal Unit

Capacity
The amount of electricity the system can provide to meet the highest level of aggregate customer demand at any given time. Also, see Peak. Also referred to as demand.

Capital costs - installed $/kW
Cost of investment in a new resource.

CCCT
Combined-Cycle Combustion Turbine. See Combined-cycle.

CF
Capacity Factor. The percentage of a resource's maximum generating ability that is actually generated.

Cholla
PacifiCorp coal plant, acquired from Arizona Public Service.

Claus plant
Part of IGCC which takes sulfur compounds, removed from the intermediate BTU gas produced by the gasifier, and reduces it to elemental sulfur.

Co-generation
The simultaneous production of electricity and useful heat energy from a fuel source. Often this is accomplished by the recovery of waste energy from an industrial or commercial operation.

CO_2
Carbon dioxide. An emission from fossil fuel burning.
Also used as abbreviated reference to the CO_2 tax scenario.

CO_2 Tax Scenario
A scenario which assumes that a federal tax of $30 per ton of CO_2 emitted is enacted.

Colorado-Ute Electric Association
Utility which recently filed for bankruptcy. PacifiCorp acquired Craig and Hayden coal plants and agreed to sale with the Public Service Company of Colorado and seasonal exchange with Tri-State.

Combined-cycle
A combustion turbine where the hot exhaust gasses from the turbine are passed through a heat recovery steam generator that produces steam for a conventional steam turbine generator.

Combustion turbine
A natural gas fired resource.

Commercial Retrofit program
Commercial sector demand-side program.

Contract rights
see Purchased power.

Craig
PacifiCorp coal plant, acquired from Colorado-Ute.

Critical water
The greatest amount of hydro energy that would be available if the region experienced a recurrence of the worst stream flow sequence on record (1928-1932).

CT
see Combustion Turbine.

D-
Used as an abbreviated reference to the DSR -30 percent sensitivity.

D+
Used as an abbreviated reference to the DSR +30 percent sensitivity.

D.S. Lost Ops.
Demand-side lost opportunities. see Demand-side programs, and Lost opportunity resource.

Decoupling
Ratemaking mechanisms to undo the link between sales and profits.

Demand
The greatest amount of electricity used by a customer or a group of customers at one point in time.

Demand-side programs
Programs which help meet the customer's need for electricity by increasing efficiencies.

Demographics
Statistical data describing the population and population trends.

Dispatchable
Resources which the utility has control over when the resource is generating, and at what level of generation.

DRI
Data Resources Institute/McGraw-Hill is a national economic research institute and consulting firm whose national and regional economic forecasts are widely used.

DRI Mountain 1 prices
DRI's forecast for fuel prices in PacifiCorp's service area.

DSR
Demand-side resources. see Demand-side programs.

DSR-
A sensitivity case which assumes that DSR acquisitions are at a level that is 30 percent less than in the other medium high cases.

DSR+
A sensitivity case which assumes that DSR acquisitions are at a level that is 30 percent more than in the other medium high cases.
Electrification Scenario
A scenario which assumes that major breakthroughs in electro-technology leads to load levels above the High Forecast.

Electro-technology
Technology which uses electricity as its source of energy.

Emissions
Pollutants resulting from a process. see CO_2, SO_2, NOx, and TSP.

End-use
Purpose for using electricity. Residential end-use is primarily for space and water heating and appliances, commercial for lighting, industrial for processing.

Energy
Total amount of electricity needed to serve customers over a period of time.

Energy FinAnswer
Commercial sector demand-side program which includes a mechanism for the customers of the program to pay for its costs.

Energy Partners
Industrial sector demand-side program.

E1
A plan using the medium high forecast for loads, and adding to the internal cost of all resources, \$1000 per ton of SO_2, \$100 per ton of NOx, \$200 per ton of TSP, and \$5 per ton of CO_2.

E2
A plan using the medium high forecast for loads, and adding to the internal cost of all resources, \$2000 per ton of SO_2, \$4000 per ton of NOx, and \$3000 per ton of TSP.

E3
A plan using the medium high forecast for loads, and adding to the internal cost of all resources, \$2000 per ton of SO_2, \$4000 per ton of NO_x, \$3000 per ton of TSP, and \$10 per ton of CO_2.

E3G
Used as an abbreviated reference to the environmental sensitivity which uses level 3 of external cost adders and high gas price assumptions.

E4
A plan using the medium high forecast for loads, and adding to the internal cost of all resources, \$2000 per ton of SO_2, \$4000 per ton of NO_x, \$3000 per ton of TSP, and \$30 per ton of CO_2.

ESc
Energy Service charge - payments included in a customer's electricity bill, for the cost of that customer's energy efficiency programs.

External costs
Costs added to the internal cost of new resources to reflect environmental externalities. Usually in dollars per ton emitted.

Externalities
The impacts one activity (i.e. electric power generation) would have on other activities (e.g. the environment, human health, etc.) that are not priced in the marketplace.

Firm power
Power which the utility is obligated to serve.

Fixed O&M (\$/kW Yr)
Operating costs which occur, regardless of the level of output of a resource.

Flashed steam plant
Geothermal plant that uses hot geothermal fluids to directly drive a turbine generator.

Fluidized-bed boiler
Boiler used in AFB coal plant. see Atmospheric fluidized-bed combustion.

G
Used as an abbreviated reference to the high gas price scenario.

Gadsby
PacifiCorp plant. It was once a coal-fired plant, but has been converted to burn natural gas.

Gasifier
Part of IGCC which takes pulverized coal and produces an intermediate BTU gas.

Geothermal fluids
Natural underground moisture that contains the heat used for geothermal energy.

Golden Carrot award
Residential sector demand-side program to encourage manufacturers to produce highly-efficient refrigerators.

Gross utility program cost
The direct utility cost, before costs or benefits have been shared with participants. Also, see TRC, and Utility cost.

GWh
Gigawatt-hours - one GWh equals 1 million kWh.

H2O
A sensitivity case which assumes that planning is done on average hydro conditions rather than on critical water, as in the other cases.

Hassle Free program
Residential sector demand-side program which encourages the use of energy efficient electric water heaters.

Hayden
PacifiCorp coal plant, acquired from Colorado-Ute.

High Forecast
4% load growth.

High Gas Scenario
A scenario which assumes that natural gas prices follow the DRI Mountain 1 forecast, and continue at the forecasted escalation rate after 2011. These assumptions result in higher gas prices than in the other cases.

HVAC
Heating, ventilation, and air conditioning.

IGCC plant
see Integrated gasification combined cycle.

Integrated gasification combined cycle
A combined cycle combustion turbine which uses, instead of natural gas, a coal gasifier as its source of fuel.

InterCompany Pool
The ICP (InterCompany Pool) is an office set up originally to arrange the scheduling of power among the following utilities: PacifiCorp, PGE, Puget, Water Power, Idaho, Montana, and Sierra Pacific. Also it arranges the allocation of surplus hydro from BPA, so BPA sees only one IOU entity. The ICP does not operate any projects. They're only a clearing house for inter-company wholesale sales and purchase transactions.

Internal costs
Costs associated with a resource, not including external costs.

kWh
Kilowatt-hours - unit of electrical energy use. The amount of energy used over a specified time period, typically one year.

Levelized (levelization)
The financial process of spreading the capital costs of an investment over a period of time, typically the number of years of useful life of the investment.

Load
The amount of electricity used by a customer or group of customers during a specified time period.

LOR
Loss of resources scenario. Assumes the Company loses some of the flexibility in operating its hydro facilities, and has reduced peaking available from BPA.

Loss of Resources Scenario
A scenario which assumes that measures taken to preserve dwindling fish population result in loss of hydro shaping ability and loss of ramp-up of PacifiCorp's BPA Capacity contract.

Lost opportunity resource
Resource that is available only for a limited time.

Low Forecast
0.5% load growth.

Low-nitrogen oxide burner
Technology available for conventional coal plant which produces lower levels of NOx.

Low-regret resource
Resources that are beneficial regardless of the level of load growth, such as demand-side resources and single-cycle combustion turbines.

LTH
The sensitivity case which assumes that the existing thermal plants operate at a 10 percent lower operating availability than in the other cases.

Luz solar plant
A thermal solar plant which can use a conventional gas-fired steam turbine, when solar energy is not available.

MCS
Model Conservation Standards, adopted in Oregon and Washington. These standards require higher levels of insulation and other energy efficiency measures.

Medium High Forecast
3% load growth.

Medium Low Forecast
1.7% load growth.

Megawatts
A unit of electrical power equal to one million watts or one thousand kilowatts.

MH
The medium high load forecast.

MH1
Used as an abbreviated reference for the medium high step 1 illustrative plan.

MH2
Used as an abbreviated reference for the medium high step 2 illustrative plan.

MH3
Used as an abbreviated reference for the medium high step 3 illustrative plan.

MH4
A resource plan for the medium high forecast of load growth, which was developed using four steps. MH4 is the adopted plan for the medium high forecast.

MH/H
A load growth uncertainty sensitivity in which medium-high load growth expected, High load growth actually occurs.

MH/Hex
A load growth uncertainty sensitivity in which medium-high load growth expected, High load growth excursion occurs before settling back at a Medium-high growth.

MH/Hex-sh
A load growth uncertainty sensitivity in which medium-high load growth expected, short High load growth excursion occurs.

MH/ML
A load growth uncertainty sensitivity in which medium-high load growth expected, Medium-low load growth actual occurs.

Mirror system
A type of thermal solar system.

ML
The medium low load forecast.

ML/L
A load growth uncertainty sensitivity in which medium-low load growth expected, Low load growth actual occurs.

ML/MH
A load growth uncertainty sensitivity in which medium-low load growth expected, Medium-high load growth actual occurs.

mills
One tenth of a penny. Used to represent the cost of electricity per kWh, for example 5 cents per kWh equals 50 mills/kWh.

mmbtu
Millions of BTUs.

MW
A unit of electric power, represents the amount of power being used or produced at one moment in time. Used as a measure for peak or capacity.

MWa
A unit of electric consumption or production over a year. It is equivalent to the energy produced by the continuous use of one megawatt of capacity over a period of one year. It is equivalent to 8760 megawatt hours, or 8760,000 kilowatt hours.

Nominal
Dollars, in the year's units as specified. Nominal dollars reflect inflation.

Nonfirm purchase
Power which a utility can purchase from another if the seller has available power at that given time.

Northwest Power Pool
The Northwest Power Pool is the already existing agency with responsibility for the Pacific Northwest Coordination Agreement's implementation. They do hydro regulation and related studies for the seventeen participating Northwest generating utilities.

NOx
Nitrogen oxide. An emission.

NPV
Net Present Value.

Op.Rev.
Operating revenue.

Operating revenue
Can also be thought of as the company's revenue requirement.

Other DSR Acquisitions
Conservation customers do on their own, without the benefit of any Company program.

Parabolic dish
A type of thermal solar system.

Peak
The maximum amount of electricity needed to serve customers at a given time.

Photovoltaic (PV)
Solar technology that directly converts sunlight into electricity.

Pulverized coal power plants
Conventional coal plant, which uses a subcritical steam boiler that burns subbituminous coal.

Purchased power
Power which the utility purchases from another utility.

QF
Qualifying Facility - private electric generating facility which "qualifies" under the 1978 PURPA Act to sell power to utilities.

R
Used as an abbreviated reference for the renewables only (coal and gas-fired resources are removed from the portfolio).

R20
The sensitivity which assumes that all renewable resources cost 20 percent less than in the other cases.

Ramp-up
Increase to a higher level.

Real
Dollars, adjusted for inflation.

Real levelized costs
Costs which are "levelized" into a series of periodic payments spanning a given time frame, and adjusted for inflation.

Real levelized fixed charge
The percentage of the total investment which is allocated to the first year after the levelization process.

Renew.
A sensitivity case which removes coal and gas-fired resources from the portfolio, except for cogeneration and solar with gas back-up.

Renewable resource
Resource which is based on natural sources, such as wind, solar, or geothermal.

Renew Only
A sensitivity case which removes coal and gas-fired resources from the portfolio, except for cogeneration and solar with gas back-up.

Reserve requirement
Additional power the utility is required to keep in reserve, in case of outages or other influences on the system which would cause the amount of power generated to be insufficient for the load needs.

Residential weatherization
Residential sector demand-side measure which increases the energy efficiency of a home.

Resource yield
Energy "produced" by a resource, expressed in MWa.

RIM Model
Resource Integration Model - the computer tool which selects new resources from a pool of available resources to balance peak and energy as it follows a load growth forecast.

Saturation level
Number of customers equipped for end-use.

SCCT
Single-Cycle Combustion Turbine. see Simple-Cycle and Combustion Turbine.

Sectors
Categorization. In the utility industry, the customer base is generally divided into residential, commercial, and industrial sectors.

Selective catalytic reduction
A method of reducing NOx emissions in a combustion turbine.

Simple-cycle
Combustion turbine where natural gas is used to produce electricity. It is similar to a jet engine. Because it can be fired quickly, it is used for peaking.

SO_2
Sulfur dioxide. An emission.

Solar pond
A type of thermal solar system.

Space Heat
An end use for electricity, typically for residential customers, to heat their homes.

Steam turbine generator
Electric generator driven by steam.

Subcritical steam boiler
Boiler used in a conventional coal plant.

Super Good Cents program
Residential sector demand-side program.

Total fixed cost ($/kW Yr)
The sum of the Annual cost and Fixed O&M. see Annual cost, and Fixed O&M.

Total levelized resource cost
The total resource cost, which is then "levelized" into a series of periodic payments over the life of the resource. see TRC.

Total resource additions
Expressed in MWa in the charts, these show the total amount of each of the categories of new resources added within the given time frame.

BALANCED PLANNING FOR GROWTH

Technical Appendix: Supply Side Resources

Resource and Market Planning Program RAMPP - 2

May 14, 1992

PACIFICORP

PacifiCorp RAMPP-2
Technical Appendix: Supply Side Resources

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DISCOUNT RATE SENSITIVITY

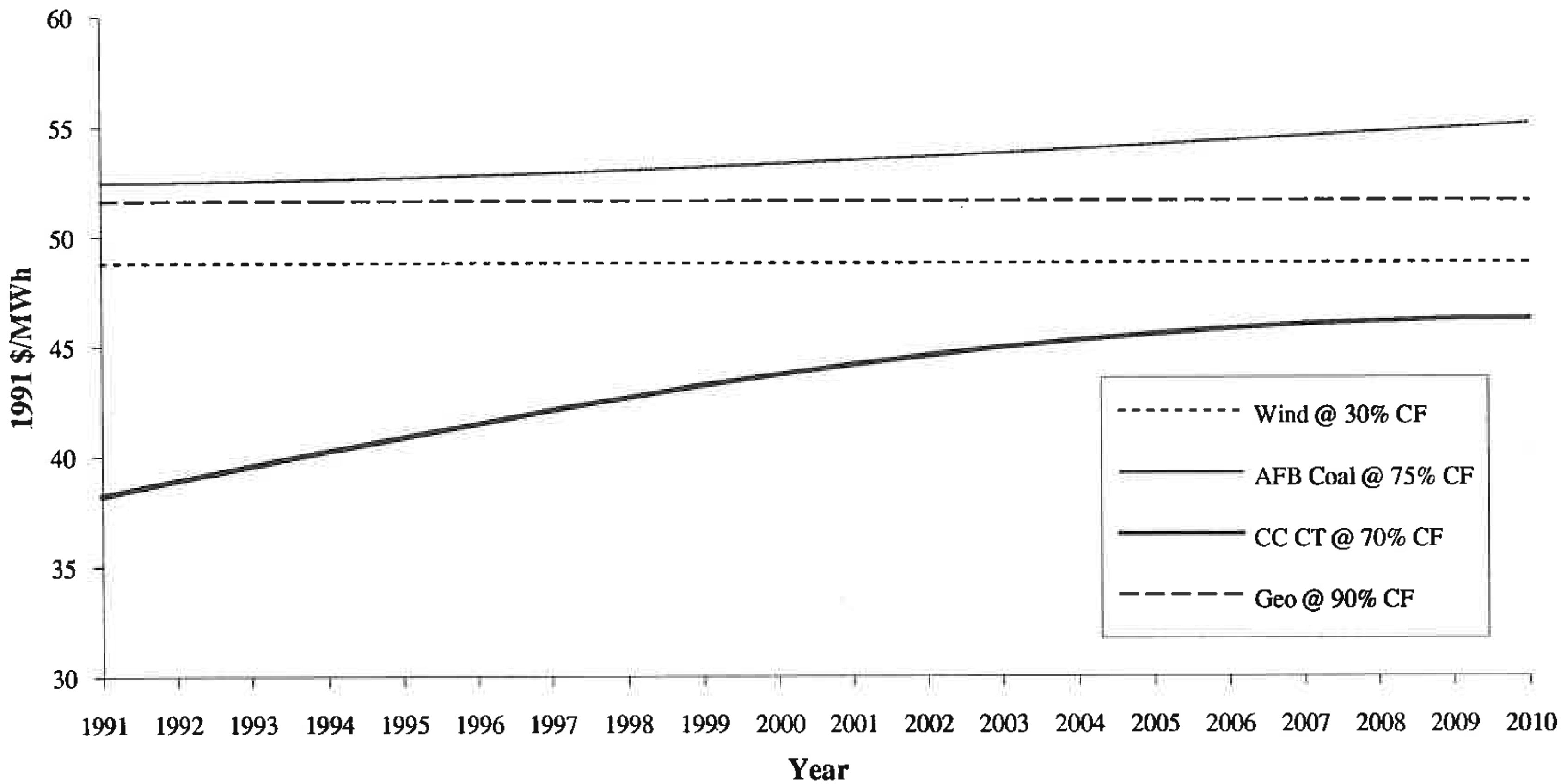
Discount Rate Sensitivity Supply Curves

Three graphs were prepared to illustrate the impacts on the resource portfolio of altering the discount rate. The three levels are 8.2, 9.54, and 10.9. 8.2 reflects a 3.0 real social cost of capital; the 9.54 represents the Company's after-tax cost of capital; the 10.9 reflects the difference between the 8.00 and the 9.54 added to the 9.54, for symmetry. The first table summarizes the results illustrated by the three graphs. The three different discount rates result in very similar curves.

PacifiCorp Electric Operations
RAMPP II Analysis of Interest Rates
Fuel and Total Cost in Year 2000

	Discount Rate	CF	Low 8.20%	Med 9.54%	High 10.90%	Difference Between High and Low	
		(1)	(2)	(3)	(4)	(5)	(6)
	Fuel (1991 $/mmbtu)					(Low-High)	(Low-High)/Low
(1)	Gas		$3.58	$3.55	$3.51	$0.07	1.96%
(2)	Coal		$1.16	$1.14	$1.13	$0.03	2.59%
	Total Costs (1991 $/MWh)					(High-Low)	(High-Low)/High
(3)	CC CT	70%	$43.23	$43.71	$44.18	$0.95	2.15%
(4)	AFB Coal	75%	$51.72	$53.30	$54.87	$3.15	5.74%
(5)	Geothermal	90%	$49.57	$51.59	$53.58	$4.01	7.48%
(6)	Wind	30%	$47.78	$48.77	$49.77	$1.99	4.00%

Real Levelized Total Cost of All Units @ 9.54%



COAL SUPPLIES

RAMPP-2
Coal Supplies to the Company's Existing Plants

The Company's existing coal plants receive their coal either from Companyu-owned mines with long-term contracts, or from spot market coal sold on 6- and 12-month contracts. There are several differences between Wyoming and Utah coal. First, the mines in Wyoming tend to be surface mines, which have low operating costs. Those in Utah tend to be underground, with higher operating costs. However, transporting coal from Wyoming to Utah would be more expensive than mining it or buying it on the spot market in Utah, due to limited rail access to plants in central Utah. Also, Wyoming coal produces fewer kWh's per ton of coal compared to Utah coal due to the lower heating value (Btu) of the Wyoming coal.

In Utah, the Hunter plant receives its coal from the Cottonwood mine; Huntington receives its coal from the Deercreek mine; and coal is purchased on the spot market for Carbon.

The Company's Wyoming plants (Johnston, Bridger, Naughton, and Wyodak) use coal from mines within Wyoming. Other Wyoming coal is generally sold outside the region, because of the low sulfur content and the low operating costs of the mines can result in a total cost (operating plus transportation) that is competitive in other regions. The Dave Johnson plant receives its coal from the Dave Johnston coal mine, and some coal is purchased from the Powder River Basin near Gillette, Wyoming on annual contracts. Bridger has an associated mine from which it receives its coal. The Naughton plant receives its coal under a contract with the Pittsburg and Midway Coal Company from a mine operated by them nearby. Naughton's coal is purchased on a long term contract, which is currently being arbitrated. Wyodak receives its coal from the associated Wyodak Mine.

The Colstrip plant receives its coal from an associated mine, and Centralia receives its coal from an associated mine. After the year 2000, outside coal will need to be added for the Centralia plant.

The Cholla plant receives its coal from the McKinley Mine, which is operated by Pittsburg and Midway Coal Company. The Company has a long-term contract with them for the coal, which extends to the year 2001. In 1994 a contract extension opportunity would allow the Company to extend that contract for 10 more years. The Company can separately negotiate for coal above the amount specified in the contract. The cost competitiveness of the contract versus alternatives is currently being examined.

The Craig plant is supplied with coal from the Trapper Mine; PacifiCorp now owns about 20 percent of the mine. Coal is also obtained from the Colowyo Mine on a variable take long term contract.

The Hayden plant receives its coal from the Seneca Mine, which is operated by Peabody Coal. The joint venture partnership has a long term contract with Peabody for the coal supply.

Spot market coal prices are also used to judge the cost effectiveness of the Company's own coal mining operations. In fact, the Company's coal mining operations are among the most efficient in the country, but the spot market provides a benchmark against which to compare the operating costs.

FUEL PRICE ASSUMPTIONS

Fuel Price Assumptions

Notes on Real prices

There are two factors that influence prices over time: One is changes in the general price levels; the second is changes in the real prices. General price levels changes are refered to as inflation, when prices trend up, or deflation, when prices trend down. The forecast price of a good in the year 2000 is typically higher than todays price. Does that mean that the good is more valuable in 2000 than today? In order to answer that simple question you must back out any forecasted inflation and examine the prices in "real" terms. Real prices are discribed in terms of a dollars buying power at some point in time. For the resource selection in RAMPP 2 the costs are discribed in terms of real 1991 dollars. As the costs are discribed in real dollars, a higher forecast price in the year 2000 than todays price implies that the good becomes more highly valued over time.

When selecting a resource, the Company also implicitly selects a stream of fuel to run the resource. Real levelized fuel costs are computed and used for comparing the life cycle cost of resources. The fuel costs are computed based on the in service date of the resource to capture projected price changes that occur before the plant is built. Real levelization differs from nominal levelization as follows: a real levelized stream of payments is constant in inflation adjusted terms, but increases in nominal terms; a nominal levelized stream is constant in nominal terms, but falling over time with inflation. Both streams are designed to yield the same net present value. The real levelized stream is similar to an economist's view of rental costs while the nominal levelized is like an auto or fixed rate mortgage payment. With care either a nominal or a real analysis will yield the same answer, however the real levelized approach tends to minimize problems with end effects. analyzing the cost impacts of resources with 25, 30, and 35 year lifes in a 20 year study window.

Coal Price Projections

Data Resources Inc. (DRI) forecasts fuel prices by region. Prices are forecasted to various customer classes. The Company Has used a burner tip price forecast (the price for fuel delivered to electric utility's plant). The price for the mountain 1 region (which includedes Colorado, Montana, Utah, and Wyoming) was used for genaric coal plants, while the fuel prices for expansions to existing plants was based on Company projections of existing coal supplies. Coal prices beyond 2010 were estimated by escalating the 2010 price forecast by the 2005-2010 annual average price increase. For Wyodak 2 and Hunter 4 the 2010-2040 price escalation was the base inflation rate, for DRI Mountain 1 Coal delivered to electric utilities, the 2010-2040 escalation rate was 1.52%/year in real terms.

Gas Price Projections

Gas price estimates for combustion turbine resources were based on either DRI's second quarter 1991 Mountain 1 gas delivered to electric utilies price or a combination of the DRI forecast and the price of gas delivered to the Company's Gadsby plant

High Case - DRI's forecast was used for 1991 to 2010 (gas prices starting at $1.948/mmbtu and escalating at 9.94% nominal. 4.61% real over the 1991-2010 time frame). After 2010 the gas price was assumed to track inflation.

High Gas Sensitivities - DRI's forecast was used for 1991 to 2010. After 2010 the gas price escalated based on the 2005-2010 DRI escalation rate (8.63% nominal,3.36% real).

Base Gas Assumptions - The escalation rates were based on DRI's forecast (9.94% nominal. 4.61% real over the 1991-2010 time frame), however, the starting point was $1.65/mmbtu. The lower starting point was based on the Company's experience in negotiating a gas contract for the Gadsby plant, which came back on line in March 1991. After 2010 the gas price was assumed to track inflation.

Natural gas has a great deal of price uncertainty, both up and down. Econometric forecasters of gas prices, such as DRI, have been forecasting gas escalation rates similar to the RAMPP 2 assumptions, for the last decade, while the actual gas prices have plunged. This trend has continued to date. DRI's forecast was for gas to go up 8% in 1991-1992. The actual gas market price has continued to fall in both nominal and real terms.

PacifiCorp Electric Operations Group
Coal Price Forecasts by Sources
Prepared for RAMPP II Cost Estimates

Nominal Discount Rate =	9.54%
Inflation Rate =	5.10%
Real discount Rate =	4.22%

	in Nominal $/mmbtu by Source			Real $/mmbtu by Source			Real Levelized by In-Service Date 1991 $/mmbtu by Region over time			
	DRI Coal	Pacific Estimates		DRI Coal	Pacific Estimates					
	Mountain 1	Powder River	Utah Coal	Mountain 1	Powder River	Utah Coal	DRI Mtn.1	Powder River	Utah Coal	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1991	1.078	0.479	0.899	1.078	0.479	0.899	1.06	0.48	0.83	1991
1992	1.096	0.503	0.931	1.043	0.479	0.886	1.06	0.48	0.83	1992
1993	1.120	0.529	0.963	1.014	0.479	0.872	1.07	0.48	0.83	1993
1994	1.152	0.556	0.997	0.992	0.479	0.859	1.07	0.48	0.82	1994
1995	1.198	0.584	1.032	0.982	0.479	0.846	1.08	0.48	0.82	1995
1996	1.252	0.614	1.068	0.976	0.479	0.833	1.09	0.48	0.82	1996
1997	1.310	0.645	1.106	0.972	0.479	0.820	1.10	0.48	0.82	1997
1998	1.373	0.678	1.162	0.969	0.479	0.820	1.12	0.48	0.82	1998
1999	1.440	0.713	1.221	0.967	0.479	0.820	1.13	0.48	0.82	1999
2000	1.512	0.749	1.284	0.966	0.479	0.820	1.14	0.48	0.82	2000
2001	1.592	0.787	1.349	0.968	0.479	0.820	1.16	0.48	0.82	2001
2002	1.683	0.827	1.418	0.974	0.479	0.820	1.18	0.48	0.82	2002
2003	1.783	0.870	1.490	0.982	0.479	0.820	1.19	0.48	0.82	2003
2004	1.889	0.914	1.566	0.989	0.479	0.820	1.21	0.48	0.82	2004
2005	2.007	0.960	1.646	1.000	0.479	0.820	1.23	0.48	0.82	2005
2006	2.138	1.009	1.730	1.014	0.479	0.820	1.25	0.48	0.82	2006
2007	2.280	1.061	1.818	1.029	0.479	0.820	1.27	0.48	0.82	2007
2008	2.436	1.115	1.911	1.046	0.479	0.820	1.29	0.48	0.82	2008
2009	2.601	1.172	2.008	1.062	0.479	0.820	1.31	0.48	0.82	2009
2010	2.776	1.232	2.111	1.079	0.479	0.820	1.33	0.48	0.82	2010
2011				1.095	0.479	0.820				
2012		Real Escalation in 2005-2010		1.112	0.479	0.820				
2013	1.52%	0.00%	0.00%	1.129	0.479	0.820				
2014				1.146	0.479	0.820				
2015		Real Escalation in 2011-2045		1.164	0.479	0.820				
2016	1.52%	0.00%	0.00%	1.181	0.479	0.820				
2017				1.199	0.479	0.820				
2018		Nominal Escalation in 2011-2045		1.218	0.479	0.820				
2019	6.70%	5.10%	5.10%	1.236	0.479	0.820				
2020				1.255	0.479	0.820				
2021				1.274	0.479	0.820				
2022				1.294	0.479	0.820				
2023		Real Escalation in 1991-2010		1.313	0.479	0.820				
2024	0.00%	0.00%	-0.48%	1.333	0.479	0.820				
2025				1.354	0.479	0.820				
2026		Nominal Escalation in 1991-2010		1.374	0.479	0.820				
2027	5.10%	5.10%	4.59%	1.395	0.479	0.820				
2028				1.417	0.479	0.820				
2029				1.438	0.479	0.820				
2030				1.460	0.479	0.820				
2031				1.482	0.479	0.820				
2032				1.505	0.479	0.820				
2033				1.528	0.479	0.820				
2034				1.551	0.479	0.820				
2035				1.575	0.479	0.820				
2036				1.599	0.479	0.820				
2037				1.623	0.479	0.820				
2038				1.648	0.479	0.820				
2039				1.673	0.479	0.820				
2040				1.699	0.479	0.820				
2041				1.725	0.479	0.820				
				1.751	0.479	0.820				

PacifiCorp Electric Operations Group
DRI Gas Price Forecasts by Region
Prepared for RAMPP II Cost Estimates

Nominal Discount Rate =	9.54%
Inflation Rate =	5.10%
Real discount Rate =	4.22%

	DRI Gas Price Forecast to Electric Utilities in Nominal $/mmbtu by Case			DRI Gas Price Forecast to Electric Utilities in Real 1991 $/mmbtu by Case			Real Levelized by Inservice Date 1991 $/mmbtu by Case over time			
	Base Case Gadsby	High Forecast Mtn.1 2Q	High Gas Sensitivity	Base Case Gadsby	High Forecast Mtn.1 2Q	High Gas Sensitivity	Base Case Gadsby	High Forecast Mtn.1 2Q	High Gas Sensitivity	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1991	1.650	1.948	1.948	1.650	1.948	1.948	2.83	3.34	3.52	1991
1992	1.788	2.111	2.111	1.701	2.009	2.009	2.91	3.44	3.66	1992
1993	1.950	2.302	2.302	1.765	2.084	2.084	3.00	3.54	3.82	1993
1994	2.222	2.623	2.623	1.914	2.259	2.259	3.09	3.65	3.97	1994
1995	2.467	2.913	2.913	2.022	2.387	2.387	3.17	3.75	4.13	1995
1996	2.696	3.183	3.183	2.102	2.482	2.482	3.25	3.84	4.29	1996
1997	2.973	3.510	3.510	2.206	2.604	2.604	3.33	3.94	4.46	1997
1998	3.292	3.886	3.886	2.324	2.743	2.743	3.41	4.03	4.63	1998
1999	3.690	4.356	4.356	2.478	2.926	2.926	3.48	4.11	4.81	1999
2000	4.123	4.868	4.868	2.635	3.111	3.111	3.55	4.19	4.99	2000
2001	4.570	5.395	5.395	2.779	3.281	3.281	3.61	4.26	5.16	2001
2002	5.045	5.956	5.956	2.919	3.446	3.446	3.66	4.32	5.34	2002
2003	5.544	6.545	6.545	3.052	3.603	3.603	3.71	4.38	5.53	2003
2004	6.056	7.150	7.150	3.172	3.745	3.745	3.75	4.43	5.72	2004
2005	6.603	7.796	7.796	3.291	3.885	3.885	3.79	4.47	5.91	2005
2006	7.206	8.508	8.508	3.417	4.034	4.034	3.82	4.51	6.11	2006
2007	7.866	9.287	9.287	3.549	4.190	4.190	3.85	4.54	6.31	2007
2008	8.552	10.096	10.096	3.671	4.334	4.334	3.86	4.56	6.52	2008
2009	9.261	10.934	10.934	3.783	4.466	4.466	3.88	4.58	6.74	2009
2010	9.988	11.792	11.792	3.882	4.583	4.583	3.88	4.58	6.96	2010
2011				3.882	4.583	4.737				2011
2012		Real Escalation in 2011-2045		3.882	4.583	4.896				2012
2013	0.00%	0.00%	3.36%	3.882	4.583	5.060				2013
2014				3.882	4.583	5.230				2014
2015		Nominal Escalation 2011-2045		3.882	4.583	5.406				2015
2016	5.10%	5.10%	8.63%	3.882	4.583	5.587				2016
2017				3.882	4.583	5.775				2017
2018				3.882	4.583	5.968				2018
2019				3.882	4.583	6.169				2019
2020	Gadsby Forecast is based on the actual p			3.882	4.583	6.376				2020
2021	paid for Gadsby Gas in 1991 escalated at			3.882	4.583	6.590				2021
2022	implicit rate for DRI Mtn.1 2Q forecast.			3.882	4.583	6.811				2022
2023				3.882	4.583	7.040				2023
2024		Nominal Escalation in 1991-2010		3.882	4.583	7.276				2024
2025	9.94%	9.94%	9.94%	3.882	4.583	7.520				2025
2026				3.882	4.583	7.773				2026
2027		Real Escalation in 1991-2010		3.882	4.583	8.034				2027
2028	4.61%	4.61%	4.61%	3.882	4.583	8.304				2028
2029				3.882	4.583	8.582				2029
2030		Real Escalation in 2005-2010		3.882	4.583	8.870				2030
2031	3.36%	3.36%	3.36%	3.882	4.583	9.168				2031
2032				3.882	4.583	9.476				2032
2033				3.882	4.583	9.794				2033
2034				3.882	4.583	10.123				2034
2035				3.882	4.583	10.463				2035
2036				3.882	4.583	10.814				2036
2037				3.882	4.583	11.177				2037
2038				3.882	4.583	11.552				2038
2039				3.882	4.583	11.940				2039
2040				3.882	4.583	12.341				2040
2041				3.882	4.583	12.755				2041

COMBUSTION TURBINE OPTIONS

Combustion Turbine Options

Simple Cycle Combustion Turbines

Combustion turbines (CT's) come in a wide range of sizes and efficiencies. Three sizes of simple cycle CT's were modeled for RAMPP 2: a 40 MW machine; a 100 MW machine; and a 150 MW machine. There are economies of scale with CT's. Smaller machines, sizes under 70 MW's, tend to be considerable more expensive than the larger machines. The largest CT's tend to have lower capital costs and better heat rates than the medium sized CT's. However, the best CT heat rates are found on small CT's that are optimized for simple cycle operation. The larger CT's are designed for optimal combined cycle usage. Lower efficiency in simple cycle operation results in a higher exhaust gas temperature. The higher temperature exhaust gases work better in the heat recovery steam generator. Thus better combined cycle performance may be obtained with a less "efficient" simple cycle. The largest CT's are the lowest cost in terms of dollars per installed kW, closely followed by medium sized CT's. The small CT's cost significantly more in terms of dollars per installed kW. However, there may be distinct advantages is small CT's for voltage or local load support that cannot be generically modeled. Additionally, joint plants may lower the cost of smaller CT capacity additions.

Combined Cycle Combustion Turbines

Combined cycle combustion turbines (CCCT's) also come in a wide range of sizes and efficiencies. However, the smallest machines tend to be quite expensive (over $1000/kW) for relatively low efficiency (a a 9400 btu/kWh heat rate, see remarks above). The smaller machines were not included in the portfolio. A Medium and larger size CCCT were modeled. The medium CCCT had 128 MW's capacity, an 8300 btu/kWh heat rate, and an $800/kW expected capital cost. The large CCCT had 250 MW's capacity, a 7600 btu/kWh heat rate, and a $760/kW expected capital cost.

Emission Controls

Burning a mmbtu of gas produces about 50-60% of the CO_2 a mmbtu of coal would produce. Particulates fall and SO_2 production goes to near zero. However, NO_x production can be fairly high. Several methods have been used to reduce NO_x. Simple cycle machines can use steam or water injection to lower the combustion temperature to control NO_x production. (NO_x formation tends to increase with burn temperature. An AFBC coal plant also uses a lower burn temperature to control NOx formation.) Combined cycle machines make use of steam or water injection and, if lower NOx emissions were required, selective catalytic reduction (SCR). SCR's were required if the CCCT's needed to produce a single digit NOx output (9 ppm NOx). It now appears that Dry Low NOx combustion may be able to produce single digit NOx emissions.

Selective Catalytic Reduction

The SCR's system reacts ammonia with the NOx to produce benign emissions. However, there are a number of issues with SCR's that need to be addressed. First of all, the catalyst is an expensive material. As SCR's use ammonia some form of ammonia must be stored at the site. SCR's work in a relatively narrow temperature window. As the temperature goes out of this window, the reaction stops. Without the reaction, both NOx and ammonia are vented to the atmosphere. If the temperature is too high the catalyst is destroyed (high exhaust temperature is the reason why SCR's are not used on simple cycle CT's). And finally, the spent catalyst is a hazardous waste material.

Dry Low NOx Combustion

The dry low NOx combustion is an emerging method to achieve low NOx emission rates without the use of water or catalysts. The basic approach is to design a combustion chamber that achieves conditions minimizing NOx formation with a good heat rate. This is a nontrivial problem. Good heat rates tend to reflect high burn temperatures, which in turn produces higher NOx emissions. However, several venders have announced plans for single digit NOx (9 ppm or below) emissions from dry low NOx CT's by 1996. As the reduction would take place in the combustion chamber, the low NOx emissions would be for simple or combined cycle CT's. The projected costs are 10-35% of the life cycle costs of SCR's, without the water use, ammonia storage, or hazardous waste disposal issues. Even in the 9-25 ppm range dry low NOx systems might be superior to the net environmental impacts of SCR's..

Long Run Fuel Options

Combustion turbines have considerable long run fuel flexibility. If fuel prices and/or expected capacity factors are low, a simple cycle CT makes sense. As fuel prices climb, and/or capacity factors increase, the CT may be converted to combined cycle operation. If natural gas prices get too high an integrated gasification unit can be added to convert coal to gas for use in the CCCT. The incremental cost of adding a heat recovery steam generator and/or an integrated gasification combined cycle (IGCC) to a simple cycle CT results in few extra costs to the total $/kW estimate provided that there is enough space and rail (or barge) access to the CT site. Several promising sites for CT's are at existing plants, or at sites previously acquired for cancelled plants. Some of these sites have good pipeline access, plenty of space, and good access to coal resources (either at mine mouth or rail). It should be noted that benefits of converting to IGCC operations would be less if CO2 is proven to be a significant environmental hazard, as an IGCC plant emits significantly more CO2 than the same CCCT units would emit if fired by natural gas.

COGENERATION OPTIONS

Cogeneration Supply

Cogeneration costs and characteristics vary widely depending on the specific needs and requirement of the host facility. The company has modeled three general price ranges: a 30-50 mills/kWh range; a 50-70 mills/kWh range; and a 70+ mills/kWh range.

Cogen 1 - 30-50 Mills/kWh

The best sites have large, relatively constant, heat requirements for nearly all hours. This means the cogen installations are large enough (say 10 MW plus) to capture considerable scale economies in capital and nonfuel O&M costs. Fuel can be obtained directly from a pipeline, cutting burner tip prices. The result is a cogen plant the has capital and variable O&M costs similar to a combined cycle CT with a 5000 btu/kWh heat rate. Even with higher fixed O&M and somewhat higher fuel prices, this is a competitive source of baseload power.

Cogen 2 - 50-70 Mills/kWh

The next best sites have smaller, more variable, heat requirements. The smaller size (say 1-10 MW) increases the capital and nonfuel O&M costs. The heat rate may be lower, and the capacity factor suffers, raising the total mills/kWh. For example, a large manufacturing plant may have a high heat requirement, but a double shift with no weekend work lowers the maximum capacity factor to under 50%. Production in excess of 50% may reduce the net heat rate,because the production does not match heat requirements for the manufacturing process.

Cogen 3 - 70+ Mills/kWh

The final category are small cogen sites (under 1 MW). These sites have high capital and O&M costs. The small size may increase the fuel costs (these sites can not economically receive service from a gas pipeline and typically take gas on an LDC's commercial tariff).

These categories are very general. Actual cogen costs are extremely site specific.

Does a plant needs a new boiler to add cogen? How long would the existing boiler last? The incremental cost of cogen will be quite different if the boiler has ten years of life left verses a boiler with one year left.

Does the plant have some free fuel? Pulp mills must burn black liquor. To dispose of black liquor in another fashion would involve

high costs. Black liquor has a negative cost to burn. A similar situation might be arising with wood wastes at sawmills. The cost of disposing wood wastes is increasing. Obtaining free disposal (by burning) might help offset the high cost of clean boilers for new hog fuel cogen facilities.
Access to natural gas pipelines. Location can significantly improve the ability of a plant to obtain low cost fuel.

General Availability of Cogen categories by case (MW capacity).

Case	$30-50/MWh	$50-70/MWh	$70 plus/MWh
Low	200	300	600
Med.Low	200	500	800
Med.High	400	700	1100
High	1000	1000	1400

RESOURCE FILES

PacifiCorp Electric Operations Group

RAMPP II Plant Cost Estimates

Costs in Real 1991 Dollars

Gas Fired Combustion Turbines

	Lg. CC CT	Med. CC CT	Lg. SC CT	Med. SC CT	Sm. SC CT
Capital Cost Ranges					
Low (-15%) $/kW =	$660.45	$760.75	$409.70	$409.70	$510.00
Expected $/kW =	$777.00	$895.00	$482.00	$482.00	$600.00
High (+15%) $/kW =	$893.55	$1,029.25	$554.30	$554.30	$690.00
Licensing Estimates					
2.5% of Capital $/kW =	$19.43	$22.38	$12.05	$12.05	$15.00
NWPPC estimates $/kW =	$6.00	$6.00	$5.00	$5.00	$5.00
Capacity in MW =	250	125	150	100	40
Economic Life in Years =	35	35	30	30	30
Fixed O&M $/kW yr =	$6.60	$6.60	$0.44	$0.44	$0.44
Variable O&M($/MWh)=	$1.87	$1.87	$4.40	$4.40	$4.40
Heat Rate (btu/kWh) =	7600	8300	11000	11500	10500
CO2 emissions vs a Pulverized Coal Plant=	42%	46%	60%	60%	60%
Fuel Type =	Gas/Oil	Gas/Oil	Gas/Oil	Gas/Oil	Gas/Oil
Total Lead Time =	4 - 5 Years	4 - 5 Years	4 - 5 Years	4 - 5 Years	4 - 5 Years

PacifiCorp Electric Operations Group
250 MW Combined Cycle Combustion Turbine Cost Est.
Developed for RAMPP II

250 MW Combined Cycle	
Capital Costs ($/kW) =	$777.00
Variable O&M ($/MWh) =	$1.54
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$83.88
Fixed O&M ($/kW yr) =	$9.34
Total Fixed Costs =	$93.22
Heat Rate (btu/kWh) =	7,600
Resource CO2 as a % of Pulverized Coal CO2=	38% - 45%

	Base Case	High Forecast	High Gas Sens.
l Fuel Price $/mmbtu	$1.65	$1.95	$1.95
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	2.83	3.34	3.52
1992	2.91	3.44	3.66
1993	3.00	3.54	3.82
1994	3.09	3.65	3.97
1995	3.17	3.75	4.13
1996	3.25	3.84	4.29
1997	3.33	3.94	4.46
1998	3.41	4.03	4.63
1999	3.48	4.11	4.81
2000	3.55	4.19	4.99
2001	3.61	4.26	5.16
2002	3.66	4.32	5.34
2003	3.71	4.38	5.53
2004	3.75	4.43	5.72
2005	3.79	4.47	5.91
2006	3.82	4.51	6.11
2007	3.85	4.54	6.31
2008	3.86	4.56	6.52
2009	3.88	4.58	6.74
2010	3.88	4.58	6.96

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	129.42	76.22	58.48	49.61	44.29	40.75	38.21	36.31	34.83	1991
1996	132.68	79.48	61.74	52.88	47.55	44.01	41.47	39.57	38.10	1996
2001	135.38	82.17	64.44	55.57	50.25	46.70	44.17	42.27	40.79	2001
2006	136.99	83.79	66.05	57.18	51.86	48.32	45.78	43.88	42.40	2006
2010	137.45	84.25	66.51	57.64	52.32	48.78	46.24	44.34	42.87	2010
High Case										
1991	133.30	80.09	62.36	53.49	48.17	44.62	42.09	40.19	38.71	1991
1996	137.15	83.95	66.21	57.34	52.02	48.47	45.94	44.04	42.56	1996
2001	140.33	87.13	69.39	60.53	55.21	51.66	49.12	47.22	45.75	2001
2006	142.24	89.03	71.30	62.43	57.11	53.56	51.03	49.13	47.65	2006
2010	142.78	89.58	71.84	62.97	57.65	54.11	51.57	49.67	48.19	2010
High Gas Sensitivity										
1991	134.69	81.48	63.74	54.88	49.56	46.01	43.48	41.58	40.10	1991
1996	140.59	87.39	69.65	60.78	55.46	51.92	49.38	47.48	46.00	1996
2001	147.20	93.99	76.26	67.39	62.07	58.52	55.99	54.09	52.61	2001
2006	154.37	101.16	83.43	74.56	69.24	65.69	63.16	61.26	59.78	2006
2010	160.86	107.65	89.92	81.05	75.73	72.18	69.65	67.75	66.27	2010

PacifiCorp Electric Operations Group
125 MW Combined Cycle Combustion Turbine Cost Est.
Developed for RAMPP II

	125 MW Combined Cycle
Capital Costs ($/kW) =	$895.00
Variable O&M ($/MWh) =	$1.54
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$96.62
Fixed O&M ($/kW yr) =	$9.34
Total Fixed Costs =	$105.96
Heat Rate (btu/kWh) =	8,300
Resource CO2 as a % of Pulverized Coal CO2=	41% - 50%

	Base Case	High Forecast	High Gas Sens.
1 Fuel Price $/mmbtu	$1.65	$1.95	$1.95
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	2.83	3.34	3.52
1992	2.91	3.44	3.66
1993	3.00	3.54	3.82
1994	3.09	3.65	3.97
1995	3.17	3.75	4.13
1996	3.25	3.84	4.29
1997	3.33	3.94	4.46
1998	3.41	4.03	4.63
1999	3.48	4.11	4.81
2000	3.55	4.19	4.99
2001	3.61	4.26	5.16
2002	3.66	4.32	5.34
2003	3.71	4.38	5.53
2004	3.75	4.43	5.72
2005	3.79	4.47	5.91
2006	3.82	4.51	6.11
2007	3.85	4.54	6.31
2008	3.86	4.56	6.52
2009	3.88	4.58	6.74
2010	3.88	4.58	6.96

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	145.94	85.46	65.31	55.23	49.18	45.15	42.27	40.11	38.43	1991
1996	149.50	89.03	68.87	58.79	52.74	48.71	45.83	43.67	41.99	1996
2001	152.45	91.97	71.81	61.73	55.69	51.65	48.77	46.61	44.93	2001
2006	154.21	93.73	73.57	63.49	57.45	53.41	50.53	48.37	46.69	2006
2010	154.71	94.24	74.08	64.00	57.95	53.92	51.04	48.88	47.20	2010
High Case										
1991	150.18	89.70	69.54	59.46	53.41	49.38	46.50	44.34	42.66	1991
1996	154.38	93.91	73.75	63.67	57.62	53.59	50.71	48.55	46.87	1996
2001	157.86	97.38	77.22	67.14	61.10	57.06	54.18	52.02	50.34	2001
2006	159.94	99.46	79.30	69.22	63.17	59.14	56.26	54.10	52.42	2006
2010	160.53	100.05	79.90	69.82	63.77	59.74	56.86	54.70	53.02	2010
High Gas Sensitivity										
1991	151.69	91.21	71.05	60.97	54.93	50.90	48.02	45.86	44.18	1991
1996	158.14	97.66	77.50	67.43	61.38	57.35	54.47	52.31	50.63	1996
2001	165.36	104.88	84.72	74.64	68.59	64.56	61.68	59.52	57.84	2001
2006	173.18	112.71	92.55	82.47	76.42	72.39	69.51	67.35	65.67	2006
2010	180.27	119.80	99.64	89.56	83.51	79.48	76.60	74.44	72.76	2010

PacifiCorp Electric Operations Group
150 MW Simple Cycle Combustion Turbine Cost Est.
Developed for RAMPP II

	150 MW Simple Cycle
Capital Costs ($/kW) =	$482.00
Variable O&M ($/MWh) =	$2.68
Real Levelized Fixed Charge =	11.07%
Capital Cost ($/kW yr) =	$53.34
Fixed O&M ($/kW yr) =	$2.33
Total Fixed Costs =	$55.67
Heat Rate (btu/kWh) =	11,000
Resource CO_2 as a % of Pulverized Coal CO_2=	55% - 66%

	Base Case	High Forecast	High Gas Sens.
1 Fuel Price $/mmbtu	$1.65	$1.95	$1.95
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	2.83	3.34	3.52
1992	2.91	3.44	3.66
1993	3.00	3.54	3.82
1994	3.09	3.65	3.97
1995	3.17	3.75	4.13
1996	3.25	3.84	4.29
1997	3.33	3.94	4.46
1998	3.41	4.03	4.63
1999	3.48	4.11	4.81
2000	3.55	4.19	4.99
2001	3.61	4.26	5.16
2002	3.66	4.32	5.34
2003	3.71	4.38	5.53
2004	3.75	4.43	5.72
2005	3.79	4.47	5.91
2006	3.82	4.51	6.11
2007	3.85	4.54	6.31
2008	3.86	4.56	6.52
2009	3.88	4.58	6.74
2010	3.88	4.58	6.96

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	97.31	65.53	54.94	49.64	46.47	44.35	42.83	41.70	40.82	1991
1996	102.03	70.25	59.66	54.37	51.19	49.07	47.56	46.42	45.54	1996
2001	105.93	74.16	63.56	58.27	55.09	52.97	51.46	50.32	49.44	2001
2006	108.27	76.49	65.90	60.60	57.42	55.30	53.79	52.66	51.77	2006
2010	108.93	77.16	66.56	61.27	58.09	55.97	54.46	53.32	52.44	2010
High Case										
1991	102.92	71.14	60.55	55.26	52.08	49.96	48.45	47.31	46.43	1991
1996	108.50	76.72	66.13	60.83	57.65	55.53	54.02	52.89	52.00	1996
2001	113.10	81.33	70.73	65.44	62.26	60.14	58.63	57.49	56.61	2001
2006	115.86	84.08	73.49	68.19	65.01	62.90	61.38	60.25	59.36	2006
2010	116.64	84.87	74.28	68.98	65.80	63.68	62.17	61.04	60.15	2010
High Gas Sensitivity										
1991	104.93	73.15	62.56	57.26	54.08	51.97	50.45	49.32	48.44	1991
1996	113.48	81.70	71.11	65.81	62.63	60.51	59.00	57.87	56.98	1996
2001	123.04	91.26	80.67	75.37	72.20	70.08	68.56	67.43	66.55	2001
2006	133.41	101.64	91.05	85.75	82.57	80.45	78.94	77.81	76.92	2006
2010	142.81	111.03	100.44	95.15	91.97	89.85	88.34	87.20	86.32	2010

PacifiCorp Electric Operations Group
100 MW Simple Cycle Combustion Turbine Cost Est.
Developed for RAMPP II

	100 MW Simple Cycle
Capital Costs ($/kW) =	$482.00
Variable O&M ($/MWh) =	$2.68
Real Levelized Fixed Charge =	11.07%
Capital Cost ($/kW yr) =	$53.34
Fixed O&M ($/kW yr) =	$2.33
Total Fixed Costs =	$55.67
Heat Rate (btu/kWh) =	11,500
Resource CO2 as a % of Pulverized Coal CO2=	57% - 69%

	Base Case	High Forecast	High Gas Sens.
l Fuel Price $/mmbtu	$1.65	$1.95	$1.95
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	2.83	3.34	3.52
1992	2.91	3.44	3.66
1993	3.00	3.54	3.82
1994	3.09	3.65	3.97
1995	3.17	3.75	4.13
1996	3.25	3.84	4.29
1997	3.33	3.94	4.46
1998	3.41	4.03	4.63
1999	3.48	4.11	4.81
2000	3.55	4.19	4.99
2001	3.61	4.26	5.16
2002	3.66	4.32	5.34
2003	3.71	4.38	5.53
2004	3.75	4.43	5.72
2005	3.79	4.47	5.91
2006	3.82	4.51	6.11
2007	3.85	4.54	6.31
2008	3.86	4.56	6.52
2009	3.88	4.58	6.74
2010	3.88	4.58	6.96

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	98.72	66.94	56.35	51.06	47.88	45.76	44.25	43.11	42.23	1991
1996	103.66	71.88	61.29	55.99	52.81	50.70	49.18	48.05	47.17	1996
2001	107.74	75.96	65.37	60.07	56.89	54.78	53.26	52.13	51.25	2001
2006	110.18	78.40	67.81	62.51	59.33	57.21	55.70	54.57	53.68	2006
2010	110.87	79.10	68.50	63.21	60.03	57.91	56.40	55.26	54.38	2010
High Case										
1991	104.59	72.81	62.22	56.92	53.75	51.63	50.11	48.98	48.10	1991
1996	110.42	78.64	68.05	62.75	59.57	57.46	55.94	54.81	53.92	1996
2001	115.23	83.46	72.86	67.57	64.39	62.27	60.76	59.62	58.74	2001
2006	118.11	86.34	75.74	70.45	67.27	65.15	63.64	62.50	61.62	2006
2010	118.94	87.16	76.57	71.27	68.09	65.98	64.46	63.33	62.44	2010
High Gas Sensitivity										
1991	106.69	74.91	64.32	59.02	55.84	53.73	52.21	51.08	50.19	1991
1996	115.62	83.85	73.25	67.96	64.78	62.66	61.15	60.01	59.13	1996
2001	125.62	93.84	83.25	77.96	74.78	72.66	71.15	70.01	69.13	2001
2006	136.47	104.69	94.10	88.80	85.63	83.51	81.99	80.86	79.98	2006
2010	146.29	114.51	103.92	98.63	95.45	93.33	91.82	90.68	89.80	2010

PacifiCorp Electric Operations Group
40 MW Simple Cycle Combustion Turbine Cost Est.
Developed for RAMPP II

40 MW Simple Cycle	
Capital Costs ($/kW) =	$600.00
Variable O&M ($/MWh) =	$2.68
Real Levelized Fixed Charge =	11.07%
Capital Cost ($/kW yr) =	$66.40
Fixed O&M ($/kW yr) =	$2.33
Total Fixed Costs =	$68.73
Heat Rate (btu/kWh) =	10,500
Resource CO2 as a % of Pulverized Coal CO2=	52% - 63%

	Base Case	High Forecast	High Gas Sens.
1 Fuel Price $/mmbtu	$1.65	$1.95	$1.95
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	2.83	3.34	3.52
1992	2.91	3.44	3.66
1993	3.00	3.54	3.82
1994	3.09	3.65	3.97
1995	3.17	3.75	4.13
1996	3.25	3.84	4.29
1997	3.33	3.94	4.46
1998	3.41	4.03	4.63
1999	3.48	4.11	4.81
2000	3.55	4.19	4.99
2001	3.61	4.26	5.16
2002	3.66	4.32	5.34
2003	3.71	4.38	5.53
2004	3.75	4.43	5.72
2005	3.79	4.47	5.91
2006	3.82	4.51	6.11
2007	3.85	4.54	6.31
2008	3.86	4.56	6.52
2009	3.88	4.58	6.74
2010	3.88	4.58	6.96

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	110.80	71.57	58.50	51.96	48.03	45.42	43.55	42.15	41.06	1991
1996	115.31	76.08	63.00	56.46	52.54	49.93	48.06	46.66	45.57	1996
2001	119.04	79.81	66.73	60.19	56.27	53.65	51.78	50.38	49.29	2001
2006	121.26	82.03	68.95	62.42	58.49	55.88	54.01	52.61	51.52	2006
2010	121.90	82.67	69.59	63.05	59.13	56.52	54.65	53.25	52.16	2010
High Case										
1991	116.16	76.93	63.85	57.32	53.39	50.78	48.91	47.51	46.42	1991
1996	121.48	82.25	69.17	62.64	58.71	56.10	54.23	52.83	51.74	1996
2001	125.88	86.65	73.57	67.03	63.11	60.50	58.63	57.23	56.14	2001
2006	128.51	89.28	76.20	69.66	65.74	63.12	61.26	59.86	58.77	2006
2010	129.26	90.03	76.95	70.42	66.49	63.88	62.01	60.61	59.52	2010
High Gas Sensitivity										
1991	118.08	78.85	65.77	59.23	55.31	52.69	50.82	49.42	48.33	1991
1996	126.24	87.01	73.93	67.39	63.47	60.85	58.98	57.58	56.49	1996
2001	135.36	96.13	83.06	76.52	72.60	69.98	68.11	66.71	65.62	2001
2006	145.27	106.04	92.96	86.42	82.50	79.88	78.02	76.61	75.53	2006
2010	154.24	115.01	101.93	95.39	91.47	88.85	86.98	85.58	84.49	2010

PacifiCorp Electric Operations Group

RAMPP II Plant Cost Estimates

Costs in Real 1991 Dollars

Renewable Options Options

	Geo. Purch.	Geothermal	Current Wind	Luz Plant *2/	Solar "2000"	Pumped Storage
Capital Cost Ranges						
Low (-15%) $/kW =	$1,360.00	$2,278.00	$637.50	$2,398.70	$2,398.70	$722.50
Expected $/kW =	$1,600.00	$2,680.00	$750.00	$2,822.00	$2,822.00	$850.00
High (+15%) $/kW =	$1,840.00	$3,082.00	$862.50	$3,245.30	$3,245.30	$977.50
Licensing Estimates						
2.5% of Capital $/kW =	$40.00	$67.00	$18.75	$70.55	$70.55	$21.25
NWPPC estimates $/kW =	$46.00	$77.05	$15.00	$14.00	$14.00	$14.00
Capacity in MW =	50	100		50	80	100
Economic Life in Years =	35	35	20	30	30	35
Fixed O&M $/kW yr =	$56.00	$93.80	$0.00	$4.82	$4.82	$3.70
Variable O&M($/MWh)=	$20.00	$3.00	$13.24	$0.00	$0.00	$3.70
Heat Rate (btu/kWh) =	N.A.	N.A.	N.A.	10000	10000	N.A.
CO_2 emissions vs a Pulverized Coal Plant=	0%	0%	0%	14%	14%	Depends
Fuel Type =	Geo. Fluid	Geo. Fluid	Wind	Solar/Gas	Solar/Gas	Electricity
Total Lead Time =	5 - 7 Years	5 - 7 Years	2 - 4 Years	2 - 4 Years	2 - 4 Years	4 - 6 Years

PacifiCorp Electric Operations Group
Geothermal Plant Cost Estimates
Developed for RAMPP II
Assuming Plant Ownership and Steam Purchase

	Mid Range
Capital Costs ($/kW) =	$1,600.00
Variable O&M ($/MWh) =	$20.00
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$172.72
Fixed O&M ($/kW yr) =	$56.00
Total Fixed Costs =	$228.72
Heat Rate (btu/kWh) =	10,000
Resource CO2 as a % of Pulverized Coal CO2=	0% - 10%

	DRI Mtn.1	Powder River	Utah
l Fuel Price $/mmbtu	NA	NA	NA
1991-2010 Real Esc.	NA	NA	NA
2011-2045 Real Esc.	NA	NA	NA

Real Levelized Fuel Costs in 1991 $/mmbtu

	DRI Mtn.1 (1)	Powder River (2)	Utah (3)
1991	0.00	0.00	0.00
1992	0.00	0.00	0.00
1993	0.00	0.00	0.00
1994	0.00	0.00	0.00
1995	0.00	0.00	0.00
1996	0.00	0.00	0.00
1997	0.00	0.00	0.00
1998	0.00	0.00	0.00
1999	0.00	0.00	0.00
2000	0.00	0.00	0.00
2001	0.00	0.00	0.00
2002	0.00	0.00	0.00
2003	0.00	0.00	0.00
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.00	0.00	0.00
2007	0.00	0.00	0.00
2008	0.00	0.00	0.00
2009	0.00	0.00	0.00
2010	0.00	0.00	0.00

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cost Est.										
1991	281.10	150.55	107.03	85.27	72.22	63.52	57.30	52.64	49.01	1991
1996	281.10	150.55	107.03	85.27	72.22	63.52	57.30	52.64	49.01	1996
2001	281.10	150.55	107.03	85.27	72.22	63.52	57.30	52.64	49.01	2001
2006	281.10	150.55	107.03	85.27	72.22	63.52	57.30	52.64	49.01	2006
2010	281.10	150.55	107.03	85.27	72.22	63.52	57.30	52.64	49.01	2010
20% Lower Capital Cost										
1991	228.88	124.44	89.63	72.22	61.78	54.81	49.84	46.11	43.21	1991
1996	228.88	124.44	89.63	72.22	61.78	54.81	49.84	46.11	43.21	1996
2001	228.88	124.44	89.63	72.22	61.78	54.81	49.84	46.11	43.21	2001
2006	228.88	124.44	89.63	72.22	61.78	54.81	49.84	46.11	43.21	2006
2010	228.88	124.44	89.63	72.22	61.78	54.81	49.84	46.11	43.21	2010
20% Higher Capital Cost										
1991	333.32	176.66	124.44	98.33	82.66	72.22	64.76	59.16	54.81	1991
1996	333.32	176.66	124.44	98.33	82.66	72.22	64.76	59.16	54.81	1996
2001	333.32	176.66	124.44	98.33	82.66	72.22	64.76	59.16	54.81	2001
2006	333.32	176.66	124.44	98.33	82.66	72.22	64.76	59.16	54.81	2006
2010	333.32	176.66	124.44	98.33	82.66	72.22	64.76	59.16	54.81	2010

PacifiCorp Electric Operations Group
Geothermal Plant Cost Estimates
Developed for RAMPP II accepting NPPC mid Range Cost.
Assuming Plant and Well Field are owned.

	Mid Range
Capital Costs ($/kW) =	$2,680.00
Variable O&M ($/MWh) =	$3.00
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$289.31
Fixed O&M ($/kW yr) =	$93.80
Total Fixed Costs =	$383.11
Heat Rate (btu/kWh) =	10,000
Resource CO2 as a % of Pulverized Coal CO2=	0% - 10%

	DRI Mtn.1	Powder River	Utah
Fuel Price $/mmbtu	NA	NA	NA
1991-2010 Real Esc.	NA	NA	NA
2011-2045 Real Esc.	NA	NA	NA

Real Levelized Fuel Costs in 1991 $/mmbtu

	DRI Mtn.1 (1)	Powder River (2)	Utah (3)
1991	0.00	0.00	0.00
1992	0.00	0.00	0.00
1993	0.00	0.00	0.00
1994	0.00	0.00	0.00
1995	0.00	0.00	0.00
1996	0.00	0.00	0.00
1997	0.00	0.00	0.00
1998	0.00	0.00	0.00
1999	0.00	0.00	0.00
2000	0.00	0.00	0.00
2001	0.00	0.00	0.00
2002	0.00	0.00	0.00
2003	0.00	0.00	0.00
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.00	0.00	0.00
2007	0.00	0.00	0.00
2008	0.00	0.00	0.00
2009	0.00	0.00	0.00
2010	0.00	0.00	0.00

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cost Est.										
1991	440.34	221.67	148.78	112.33	90.47	75.89	65.48	57.67	51.59	1991
1996	440.34	221.67	148.78	112.33	90.47	75.89	65.48	57.67	51.59	1996
2001	440.34	221.67	148.78	112.33	90.47	75.89	65.48	57.67	51.59	2001
2006	440.34	221.67	148.78	112.33	90.47	75.89	65.48	57.67	51.59	2006
2010	440.34	221.67	148.78	112.33	90.47	75.89	65.48	57.67	51.59	2010
20% Lower Capital Cost										
1991	352.87	177.93	119.62	90.47	72.97	61.31	52.98	46.73	41.87	1991
1996	352.87	177.93	119.62	90.47	72.97	61.31	52.98	46.73	41.87	1996
2001	352.87	177.93	119.62	90.47	72.97	61.31	52.98	46.73	41.87	2001
2006	352.87	177.93	119.62	90.47	72.97	61.31	52.98	46.73	41.87	2006
2010	352.87	177.93	119.62	90.47	72.97	61.31	52.98	46.73	41.87	2010
20% Higher Capital Cost										
1991	527.80	265.40	177.93	134.20	107.96	90.47	77.97	68.60	61.31	1991
1996	527.80	265.40	177.93	134.20	107.96	90.47	77.97	68.60	61.31	1996
2001	527.80	265.40	177.93	134.20	107.96	90.47	77.97	68.60	61.31	2001
2006	527.80	265.40	177.93	134.20	107.96	90.47	77.97	68.60	61.31	2006
2010	527.80	265.40	177.93	134.20	107.96	90.47	77.97	68.60	61.31	2010

Wind Turbine Cost Estimates

Wind Turbine Cost Estimates

Developed for RAMPP II

Accepting Current Developer Costs

	Current Wind
Capital Costs ($/kW) =	$750.00
Variable O&M ($/MWh) =	$13.24
Real Levelized Fixed Charge =	11.86%
Capital Cost ($/kW yr) =	$88.94
Fixed O&M ($/kW yr) =	$4.45
Total Fixed Costs =	$93.38
Heat Rate (btu/kWh) =	NA
Resource CO2 as a % of Pulverized Coal CO2=	0% - 0%

	DRI Mtn.1	Powder River	Utah
l Fuel Price $/mmbtu	NA	NA	NA
1991-2010 Real Esc.	NA	NA	NA
2011-2045 Real Esc.	NA	NA	NA

Real Levelized Fuel Costs in 1991 $/mmbtu

	DRI Mtn.1	Powder River	Utah
	(1)	(2)	(3)
1991	0.00	0.00	0.00
1992	0.00	0.00	0.00
1993	0.00	0.00	0.00
1994	0.00	0.00	0.00
1995	0.00	0.00	0.00
1996	0.00	0.00	0.00
1997	0.00	0.00	0.00
1998	0.00	0.00	0.00
1999	0.00	0.00	0.00
2000	0.00	0.00	0.00
2001	0.00	0.00	0.00
2002	0.00	0.00	0.00
2003	0.00	0.00	0.00
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.00	0.00	0.00
2007	0.00	0.00	0.00
2008	0.00	0.00	0.00
2009	0.00	0.00	0.00
2010	0.00	0.00	0.00

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	22%	23%	24%	25%	26%	27%	28%	29%	30%	
	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	
Base Cost Est.										
1991	61.69	59.59	57.66	55.88	54.24	52.72	51.31	50.00	48.77	1991
1996	61.69	59.59	57.66	55.88	54.24	52.72	51.31	50.00	48.77	1996
2001	61.69	59.59	57.66	55.88	54.24	52.72	51.31	50.00	48.77	2001
2006	61.69	59.59	57.66	55.88	54.24	52.72	51.31	50.00	48.77	2006
2010	61.69	59.59	57.66	55.88	54.24	52.72	51.31	50.00	48.77	2010
20% Lower Capital Cost										
1991	52.00	50.32	48.77	47.35	46.04	44.83	43.70	42.65	41.67	1991
1996	52.00	50.32	48.77	47.35	46.04	44.83	43.70	42.65	41.67	1996
2001	52.00	50.32	48.77	47.35	46.04	44.83	43.70	42.65	41.67	2001
2006	52.00	50.32	48.77	47.35	46.04	44.83	43.70	42.65	41.67	2006
2010	52.00	50.32	48.77	47.35	46.04	44.83	43.70	42.65	41.67	2010
20% Higher Capital Cost										
1991	71.39	68.86	66.54	64.41	62.44	60.62	58.93	57.35	55.88	1991
1996	71.39	68.86	66.54	64.41	62.44	60.62	58.93	57.35	55.88	1996
2001	71.39	68.86	66.54	64.41	62.44	60.62	58.93	57.35	55.88	2001
2006	71.39	68.86	66.54	64.41	62.44	60.62	58.93	57.35	55.88	2006
2010	71.39	68.86	66.54	64.41	62.44	60.62	58.93	57.35	55.88	2010

PacifiCorp Electric Operations Group
Luz Solar Thermal Plant Cost Estimates
Developed for RAMPP II
Assumed Costs as of 1998

	Luz Plant
Capital Costs ($/kW) =	$2,822.00
Variable O&M ($/MWh) =	$3.55
Real Levelized Fixed Charge =	10.30%
Capital Cost ($/kW yr) =	$290.72
Fixed O&M ($/kW yr) =	$35.97
Total Fixed Costs =	$326.69
Heat Rate (btu/kWh) =	10,000
Resource CO2 as a % of Pulverized Coal CO2=	14% - 18%

	Base Case	High Forecast	High Gas Sens.
l Fuel Price $/mmbtu	$1.65	$1.95	$1.95
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	2.83	3.34	3.52
1992	2.91	3.44	3.66
1993	3.00	3.54	3.82
1994	3.09	3.65	3.97
1995	3.17	3.75	4.13
1996	3.25	3.84	4.29
1997	3.33	3.94	4.46
1998	3.41	4.03	4.63
1999	3.48	4.11	4.81
2000	3.55	4.19	4.99
2001	3.61	4.26	5.16
2002	3.66	4.32	5.34
2003	3.71	4.38	5.53
2004	3.75	4.43	5.72
2005	3.79	4.47	5.91
2006	3.82	4.51	6.11
2007	3.85	4.54	6.31
2008	3.86	4.56	6.52
2009	3.88	4.58	6.74
2010	3.88	4.58	6.96

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	376.48	190.02	127.86	103.85	89.44	79.83	72.97	67.82	63.82	1991
1996	376.48	190.02	127.86	104.92	91.15	81.98	75.42	70.51	66.68	1996
2001	376.48	190.02	127.86	105.81	92.57	83.75	77.45	72.72	69.05	2001
2006	376.48	190.02	127.86	106.34	93.42	84.81	78.66	74.05	70.46	2006
2010	376.48	190.02	127.86	106.49	93.66	85.11	79.01	74.43	70.87	2010
High Case										
1991	376.48	190.02	127.86	105.12	91.48	82.38	75.88	71.01	67.22	1991
1996	376.48	190.02	127.86	106.39	93.50	84.92	78.78	74.18	70.60	1996
2001	376.48	190.02	127.86	107.44	95.18	87.01	81.17	76.80	73.39	2001
2006	376.48	190.02	127.86	108.06	96.18	88.26	82.60	78.36	75.06	2006
2010	376.48	190.02	127.86	108.24	96.47	88.62	83.01	78.81	75.54	2010
High Gas Sensitivity										
1991	376.48	190.02	127.86	105.58	92.21	83.29	76.93	72.15	68.44	1991
1996	376.48	190.02	127.86	107.52	95.32	87.18	81.37	77.01	73.62	1996
2001	376.48	190.02	127.86	109.69	98.79	91.53	86.34	82.44	79.41	2001
2006	376.48	190.02	127.86	112.05	102.57	96.24	91.73	88.34	85.70	2006
2010	376.48	190.02	127.86	114.19	105.98	100.51	96.61	93.68	91.40	2010

PacifiCorp Electric Operations Group
DRAFT 100 MW Modular Pumped Storage Cost Est.
Developed for RAMPP II
Based On Mountain 1 Fuel Prices

	100 MW Combined Cycle
Capital Costs ($/kW) =	$760.00
Variable O&M ($/MWh) =	$1.87
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$82.04
Fixed O&M ($/kW yr) =	$0.00
Total Fixed Costs =	$82.04

Heat Rate (btu/kWh) = NA

CCCT CO2 emissions vs a Pulverized Coal Plant= 0.00

	Real Levelized 1991 $/MWh Offpeak Energy (1)	Real Levelized Fuel" @75% Eff. 1991 $/MWh (2)	Real Levelized O&M Costs 1991 $/MWh (3)	Real Levelized Running Costs 1991 $/MWh (4)
1991	16.00	21.33	1.87	23.21
1992	16.00	21.33	1.87	23.21
1993	16.00	21.33	1.87	23.21
1994	16.00	21.33	1.87	23.21
1995	16.00	21.33	1.87	23.21
1996	16.00	21.33	1.87	23.21
1997	16.00	21.33	1.87	23.21
1998	16.00	21.33	1.87	23.21
1999	16.00	21.33	1.87	23.21
2000	16.00	21.33	1.87	23.21
2001	16.00	21.33	1.87	23.21
2002	16.00	21.33	1.87	23.21
2003	16.00	21.33	1.87	23.21
2004	16.00	21.33	1.87	23.21
2005	16.00	21.33	1.87	23.21
2006	16.00	21.33	1.87	23.21
2007	16.00	21.33	1.87	23.21
2008	16.00	21.33	1.87	23.21
2009	16.00	21.33	1.87	23.21
2010	16.00	21.33	1.87	23.21

Total Real Levelized Costs by CF in 1991 $/MWh

	5% (5)	10% (6)	15% (7)	20% (8)	25% (9)	30% (10)	35% (11)	40% (12)	
1991	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1991
1992	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1992
1993	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1993
1994	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1994
1995	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1995
1996	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1996
1997	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1997
1998	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1998
1999	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	1999
2000	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2000
2001	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2001
2002	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2002
2003	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2003
2004	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2004
2005	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2005
2006	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2006
2007	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2007
2008	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2008
2009	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2009
2010	210.52	116.86	85.64	70.03	60.67	54.42	49.96	46.62	2010

PacifiCorp Electric Operations Group
RAMPP II Plant Cost Estimates
Costs in Real 1991 Dollars

	Cogeneration Options		
	Cogen 1	**Cogen 2**	**Cogen 3**
Capital Cost Ranges			
Low (-15%) $/kW =	$595.00	$952.00	$1,428.00
Expected $/kW =	$700.00	$1,120.00	$1,680.00
High (+15%) $/kW =	$805.00	$1,288.00	$1,932.00
Licensing Estimates			
2.5% of Capital $/kW =	$17.50	$28.00	$42.00
NWPPC estimates $/kW =	$20.13	$32.20	$48.30
Capacity in MW =	100	100	100
Economic Life in Years =	35	35	35
Fixed O&M $/kW yr =	$32.85	$32.85	$32.85
Variable O&M($/MWh)=	$2.50	$10.00	$10.00
Heat Rate (btu/kWh) =	5000	6500	6500
CO2 emissions vs a Pulverized Coal Plant=	27%	36%	36%
Fuel Type =	Gas, Oil, or Misc.	Gas, Oil, or Misc.	Gas, Oil, or Misc.
Total Lead Time =	1 - 4 Years	2 - 4 Years	2 - 4 Years

PacifiCorp Electric Operations Group
100 MW Best Site Cogeneration Cost Est.
Developed for RAMPP II

100 MW Cogeneration 1	
Capital Costs ($/kW) =	$700.00
Variable O&M ($/MWh) =	$2.50
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$75.57
Fixed O&M ($/kW yr) =	$32.85
Total Fixed Costs =	$108.42
Heat Rate (btu/kWh) =	5,000
Resource CO2 as a % of Pulverized Coal CO2=	25% - 30%

	Base Case	High Forecast	High Gas Sens.
l Fuel Price $/mmbtu	$1.95	$1.95	$1.95
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	3.34	3.34	3.52
1992	3.44	3.44	3.66
1993	3.54	3.54	3.82
1994	3.65	3.65	3.97
1995	3.75	3.75	4.13
1996	3.84	3.84	4.29
1997	3.94	3.94	4.46
1998	4.03	4.03	4.63
1999	4.11	4.11	4.81
2000	4.19	4.19	4.99
2001	4.26	4.26	5.16
2002	4.32	4.32	5.34
2003	4.38	4.38	5.53
2004	4.43	4.43	5.72
2005	4.47	4.47	5.91
2006	4.51	4.51	6.11
2007	4.54	4.54	6.31
2008	4.56	4.56	6.52
2009	4.58	4.58	6.74
2010	4.58	4.58	6.96

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	142.94	81.06	60.43	50.12	43.93	39.80	36.86	34.65	32.93	1991
1996	145.47	83.59	62.96	52.65	46.46	42.34	39.39	37.18	35.46	1996
2001	147.57	85.69	65.06	54.74	48.56	44.43	41.48	39.27	37.56	2001
2006	148.82	86.94	66.31	56.00	49.81	45.68	42.74	40.53	38.81	2006
2010	149.18	87.29	66.67	56.35	50.17	46.04	43.09	40.88	39.17	2010
High Case										
1991	142.94	81.06	60.43	50.12	43.93	39.80	36.86	34.65	32.93	1991
1996	145.47	83.59	62.96	52.65	46.46	42.34	39.39	37.18	35.46	1996
2001	147.57	85.69	65.06	54.74	48.56	44.43	41.48	39.27	37.56	2001
2006	148.82	86.94	66.31	56.00	49.81	45.68	42.74	40.53	38.81	2006
2010	149.18	87.29	66.67	56.35	50.17	46.04	43.09	40.88	39.17	2010
High Gas Sensitivity										
1991	143.85	81.97	61.34	51.03	44.84	40.72	37.77	35.56	33.84	1991
1996	147.74	85.85	65.23	54.91	48.73	44.60	41.65	39.44	37.73	1996
2001	152.08	90.20	69.57	59.26	53.07	48.95	46.00	43.79	42.07	2001
2006	156.80	94.92	74.29	63.98	57.79	53.66	50.72	48.51	46.79	2006
2010	161.07	99.19	78.56	68.25	62.06	57.93	54.99	52.78	51.06	2010

PacifiCorp Electric Operations Group
100 MW Second Cogeneration Cost Est.
Developed for RAMPP II

100 MW Cogeneration 2	
Capital Costs ($/kW) =	$1,120.00
Variable O&M ($/MWh) =	$10.00
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$120.90
Fixed O&M ($/kW yr) =	$32.85
Total Fixed Costs =	$153.75
Heat Rate (btu/kWh) =	6,500
Resource CO_2 as a % of Pulverized Coal CO_2=	32% - 39%

	Base Case	High Forecast	High Gas Sens.
l Fuel Price $/mmbtu	$1.95	$1.95	$1.95
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	3.34	3.34	3.52
1992	3.44	3.44	3.66
1993	3.54	3.54	3.82
1994	3.65	3.65	3.97
1995	3.75	3.75	4.13
1996	3.84	3.84	4.29
1997	3.94	3.94	4.46
1998	4.03	4.03	4.63
1999	4.11	4.11	4.81
2000	4.19	4.19	4.99
2001	4.26	4.26	5.16
2002	4.32	4.32	5.34
2003	4.38	4.38	5.53
2004	4.43	4.43	5.72
2005	4.47	4.47	5.91
2006	4.51	4.51	6.11
2007	4.54	4.54	6.31
2008	4.56	4.56	6.52
2009	4.58	4.58	6.74
2010	4.58	4.58	6.96

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	207.20	119.44	90.19	75.56	66.78	60.93	56.75	53.62	51.18	1991
1996	210.49	122.73	93.48	78.85	70.08	64.23	60.05	56.91	54.47	1996
2001	213.21	125.45	96.20	81.58	72.80	66.95	62.77	59.64	57.20	2001
2006	214.84	127.08	97.83	83.20	74.43	68.58	64.40	61.26	58.82	2006
2010	215.31	127.55	98.29	83.67	74.89	69.04	64.86	61.73	59.29	2010
High Case										
1991	207.20	119.44	90.19	75.56	66.78	60.93	56.75	53.62	51.18	1991
1996	210.49	122.73	93.48	78.85	70.08	64.23	60.05	56.91	54.47	1996
2001	213.21	125.45	96.20	81.58	72.80	66.95	62.77	59.64	57.20	2001
2006	214.84	127.08	97.83	83.20	74.43	68.58	64.40	61.26	58.82	2006
2010	215.31	127.55	98.29	83.67	74.89	69.04	64.86	61.73	59.29	2010
High Gas Sensitivity										
1991	208.38	120.62	91.37	76.74	67.97	62.12	57.94	54.80	52.37	1991
1996	213.43	125.68	96.42	81.80	73.02	67.17	62.99	59.86	57.42	1996
2001	219.08	131.33	102.07	87.45	78.67	72.82	68.64	65.51	63.07	2001
2006	225.22	137.46	108.20	93.58	84.80	78.95	74.77	71.64	69.20	2006
2010	230.77	143.01	113.76	99.13	90.35	84.50	80.32	77.19	74.75	2010

PacifiCorp Electric Operations Group
100 MW Third Cogeneration Cost Est.
Developed for RAMPP II

Note: Third Estimate Cogeneration assumes a 40% higher gas price.
The gas is assumed to be delivered at an LDC'c Commercial Tarriff.

100 MW Cogeneration 3	
Capital Costs ($/kW) =	$1,680.00
Variable O&M ($/MWh) =	$10.00
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$181.36
Fixed O&M ($/kW yr) =	$32.85
Total Fixed Costs =	$214.21
Heat Rate (btu/kWh) =	6,500
Resource CO2 as a % of Pulverized Coal CO2=	32% - 39%

	Base Case	High Forecast	High Gas Sens.
l Fuel Price $/mmbtu	$2.73	$2.73	$2.73
1991-2010 Real Esc.	4.61%	4.61%	4.61%
2011-2045 Real Esc.	0.00%	0.00%	3.36%

Real Levelized Fuel Costs in 1991 $/mmbtu

	Base Cases (1)	High Forecast (2)	High Gas Sens. (3)
1991	4.67	4.67	4.92
1992	4.81	4.81	5.13
1993	4.96	4.96	5.34
1994	5.11	5.11	5.56
1995	5.25	5.25	5.79
1996	5.38	5.38	6.01
1997	5.51	5.51	6.25
1998	5.64	5.64	6.49
1999	5.76	5.76	6.73
2000	5.87	5.87	6.98
2001	5.97	5.97	7.23
2002	6.05	6.05	7.48
2003	6.13	6.13	7.74
2004	6.20	6.20	8.00
2005	6.26	6.26	8.27
2006	6.32	6.32	8.55
2007	6.36	6.36	8.84
2008	6.39	6.39	9.13
2009	6.41	6.41	9.43
2010	6.42	6.42	9.75

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Base Cases										
1991	284.88	162.61	121.86	101.48	89.26	81.11	75.28	70.92	67.52	1991
1996	289.49	167.23	126.47	106.09	93.87	85.72	79.89	75.53	72.13	1996
2001	293.30	171.04	130.28	109.91	97.68	89.53	83.71	79.34	75.94	2001
2006	295.58	173.32	132.56	112.18	99.96	91.81	85.98	81.62	78.22	2006
2010	296.23	173.97	133.21	112.84	100.61	92.46	86.64	82.27	78.87	2010
High Case										
1991	284.88	162.61	121.86	101.48	89.26	81.11	75.28	70.92	67.52	1991
1996	289.49	167.23	126.47	106.09	93.87	85.72	79.89	75.53	72.13	1996
2001	293.30	171.04	130.28	109.91	97.68	89.53	83.71	79.34	75.94	2001
2006	295.58	173.32	132.56	112.18	99.96	91.81	85.98	81.62	78.22	2006
2010	296.23	173.97	133.21	112.84	100.61	92.46	86.64	82.27	78.87	2010
High Gas Sensitivity										
1991	286.54	164.27	123.52	103.14	90.92	82.77	76.94	72.58	69.18	1991
1996	293.61	171.35	130.59	110.21	97.99	89.84	84.02	79.65	76.25	1996
2001	301.52	179.26	138.50	118.12	105.90	97.75	91.93	87.56	84.16	2001
2006	310.10	187.84	147.09	126.71	114.48	106.33	100.51	96.14	92.75	2006
2010	317.88	195.61	154.86	134.48	122.26	114.10	108.28	103.92	100.52	2010

PacifiCorp Electric Operations Group

RAMPP II Plant Cost Estimates

Costs in Real 1991 Dollars

	New Coal Fired Options			
	Hunter 4	Wyodak 2	AFB Coal	IGCC Coal
Capital Cost Ranges				
Low (-15%) $/kW =	$1,344.08	$1,570.00	$1,576.00	$1,672.00
Expected $/kW =	$1,581.27	$1,847.06	$1,970.00	$2,090.00
High (+15%) $/kW =	$1,818.46	$2,124.12	$2,364.00	$2,508.00
Licensing Estimates				
2.5% of Capital $/kW =	$39.53	$46.18	$49.25	$52.25
NWPPC estimates $/kW =	$30.00	$30.00	$41.00	$38.00
Capacity in MW =	400	256	250	500
Economic Life in Years =	35	35	35	35
Fixed O&M $/kW yr =	$0.00	$0.00	$32.40	$34.00
Variable O&M($/MWh)=	$3.44	$4.16	$4.50	$3.47
Heat Rate (btu/kWh) =	10000	11000	10045	9500
CO2 emissions vs a Pulverized Coal Plant=	100%	110%	100%	95%
Fuel Type =	Coal	Coal	Coal, Etc.	Coal, Etc.
Total Lead Time =	5 - 7 Years	5 - 7 Years	7 - 10 Years	7 - 10 Years

PacifiCorp Electric Operations Group
Hunter Unit #4 Cost Estimates
Developed for RAMPP II
Based On Pacific Utah Fuel Prices

Hunter Unit #4 - 400 MW	
Capital Costs ($/kW) =	$1,581.27
Variable O&M ($/MWh) =	$3.44
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$170.70
Fixed O&M ($/kW yr) =	$0.00
Total Fixed Costs =	$170.70
Heat Rate (btu/kWh) =	10,000
Resource CO_2 as a % of Pulverized Coal CO_2=	90% - 110%

	DRI Mtn.1	Powder River	Utah
l Fuel Price $/mmbtu	$1.078	$0.455	$0.899
1991-2010 Real Esc.	0.00%	0.00%	-0.48%
2011-2045 Real Esc.	1.52%	0.00%	0.00%

Real Levelized Fuel Costs in 1991 $/mmbtu

	DRI Mtn.1 (1)	Powder River (2)	Utah (3)
1991	1.06	0.48	0.83
1992	1.06	0.48	0.83
1993	1.07	0.48	0.83
1994	1.07	0.48	0.82
1995	1.08	0.48	0.82
1996	1.09	0.48	0.82
1997	1.10	0.48	0.82
1998	1.12	0.48	0.82
1999	1.13	0.48	0.82
2000	1.14	0.48	0.82
2001	1.16	0.48	0.82
2002	1.18	0.48	0.82
2003	1.19	0.48	0.82
2004	1.21	0.48	0.82
2005	1.23	0.48	0.82
2006	1.25	0.48	0.82
2007	1.27	0.48	0.82
2008	1.29	0.48	0.82
2009	1.31	0.48	0.82
2010	1.33	0.48	0.82

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

Utah	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
1991	206.64	109.21	76.73	60.49	50.75	44.26	39.62	36.14	33.43	1991
1996	206.51	109.08	76.60	60.36	50.62	44.13	39.49	36.01	33.30	1996
2001	206.50	109.07	76.60	60.36	50.62	44.12	39.48	36.00	33.29	2001
2006	206.50	109.07	76.60	60.36	50.62	44.12	39.48	36.00	33.29	2006
2010	206.50	109.07	76.60	60.36	50.62	44.12	39.48	36.00	33.29	2010

PacifiCorp Electric Operations Group
Wyodak Unit #2 Cost Estimates
Developed for RAMPP II
Based On Pacific Powder River Fuel Prices

Wyodak Unit #2 - 320 MW w/o Transmission

Capital Costs ($/kW) =	$1,847.06
Variable O&M ($/MWh) =	$4.16
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$199.39
Fixed O&M ($/kW yr) =	$0.00
Total Fixed Costs =	$199.39
Heat Rate (btu/kWh) =	11,000
Resource CO2 as a % of Pulverized Coal CO2=	99% - 121%

	DRI Mtn.1	Powder River	Utah
1 Fuel Price $/mmbtu	$1.078	$0.455	$0.899
1991-2010 Real Esc.	0.00%	0.00%	-0.48%
2011-2045 Real Esc.	1.52%	0.00%	0.00%

Real Levelized Fuel Costs in 1991 $/mmbtu

	DRI Mtn.1 (1)	Powder River (2)	Utah (3)
1991	1.06	0.48	0.83
1992	1.06	0.48	0.83
1993	1.07	0.48	0.83
1994	1.07	0.48	0.82
1995	1.08	0.48	0.82
1996	1.09	0.48	0.82
1997	1.10	0.48	0.82
1998	1.12	0.48	0.82
1999	1.13	0.48	0.82
2000	1.14	0.48	0.82
2001	1.16	0.48	0.82
2002	1.18	0.48	0.82
2003	1.19	0.48	0.82
2004	1.21	0.48	0.82
2005	1.23	0.48	0.82
2006	1.25	0.48	0.82
2007	1.27	0.48	0.82
2008	1.29	0.48	0.82
2009	1.31	0.48	0.82
2010	1.33	0.48	0.82

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
Powder River										
1991	237.04	123.23	85.29	66.33	54.95	47.36	41.94	37.87	34.71	1991
1996	237.04	123.23	85.29	66.33	54.95	47.36	41.94	37.87	34.71	1996
2001	237.04	123.23	85.29	66.33	54.95	47.36	41.94	37.87	34.71	2001
2006	237.04	123.23	85.29	66.33	54.95	47.36	41.94	37.87	34.71	2006
2010	237.04	123.23	85.29	66.33	54.95	47.36	41.94	37.87	34.71	2010

PacifiCorp Electric Operations Group
250 MW AFBC Coal Cost Est.
Developed for RAMPP II

	250 MW AFBC
Capital Costs ($/kW) =	$1,970.00
Variable O&M ($/MWh) =	$4.50
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$212.66
Fixed O&M ($/kW yr) =	$32.40
Total Fixed Costs =	$245.06
Heat Rate (btu/kWh) =	10,045
Resource CO2 as a % of Pulverized Coal CO2=	91% - 110%

	DRI Mtn.1	Powder River	Utah
l Fuel Price $/mmbtu	$1.078	$0.455	$0.899
1991-2010 Real Esc.	0.00%	0.00%	-0.48%
2011-2045 Real Esc.	1.52%	0.00%	0.00%

Real Levelized Fuel Costs in 1991 $/mmbtu

	DRI Mtn.1 (1)	Powder River (2)	Utah (3)
1991	1.06	0.48	0.83
1992	1.06	0.48	0.83
1993	1.07	0.48	0.83
1994	1.07	0.48	0.82
1995	1.08	0.48	0.82
1996	1.09	0.48	0.82
1997	1.10	0.48	0.82
1998	1.12	0.48	0.82
1999	1.13	0.48	0.82
2000	1.14	0.48	0.82
2001	1.16	0.48	0.82
2002	1.18	0.48	0.82
2003	1.19	0.48	0.82
2004	1.21	0.48	0.82
2005	1.23	0.48	0.82
2006	1.25	0.48	0.82
2007	1.27	0.48	0.82
2008	1.29	0.48	0.82
2009	1.31	0.48	0.82
2010	1.33	0.48	0.82

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
DRI Mtn.1										
1991	294.87	155.00	108.37	85.06	71.07	61.75	55.09	50.09	46.21	1991
1996	295.23	155.35	108.73	85.42	71.43	62.10	55.44	50.45	46.56	1996
2001	295.91	156.03	109.41	86.09	72.11	62.78	56.12	51.12	47.24	2001
2006	296.79	156.91	110.29	86.98	72.99	63.66	57.00	52.01	48.12	2006
2010	297.57	157.70	111.07	87.76	73.77	64.45	57.79	52.79	48.91	2010
Powder River										
1991	289.06	149.19	102.56	79.25	65.26	55.94	49.28	44.28	40.39	1991
1996	289.06	149.19	102.56	79.25	65.26	55.94	49.28	44.28	40.39	1996
2001	289.06	149.19	102.56	79.25	65.26	55.94	49.28	44.28	40.39	2001
2006	289.06	149.19	102.56	79.25	65.26	55.94	49.28	44.28	40.39	2006
2010	289.06	149.19	102.56	79.25	65.26	55.94	49.28	44.28	40.39	2010
Utah										
1991	292.63	152.75	106.13	82.82	68.83	59.50	52.84	47.85	43.96	1991
1996	292.50	152.62	106.00	82.69	68.70	59.37	52.71	47.72	43.83	1996
2001	292.49	152.62	105.99	82.68	68.69	59.37	52.71	47.71	43.83	2001
2006	292.49	152.62	105.99	82.68	68.69	59.37	52.71	47.71	43.83	2006
2010	292.49	152.62	105.99	82.68	68.69	59.37	52.71	47.71	43.83	2010

PacifiCorp Electric Operations Group
500 MW IGCC Coal Cost Est.
Developed for RAMPP II

	500 MW IGCC.
Capital Costs ($/kW) =	$2,090.00
Variable O&M ($/MWh) =	$3.47
Real Levelized Fixed Charge =	10.80%
Capital Cost ($/kW yr) =	$225.62
Fixed O&M ($/kW yr) =	$34.00
Total Fixed Costs =	$259.62
Heat Rate (btu/kWh) =	9,500
Resource CO2 as a % of Pulverized Coal CO2=	86% - 104%

	DRI Mtn.1	Powder River	Utah
l Fuel Price $/mmbtu	$1.078	$0.455	$0.899
1991-2010 Real Esc.	0.00%	0.00%	-0.48%
2011-2045 Real Esc.	1.52%	0.00%	0.00%

Real Levelized Fuel Costs in 1991 $/mmbtu

	DRI Mtn.1 (1)	Powder River (2)	Utah (3)
1991	1.06	0.48	0.83
1992	1.06	0.48	0.83
1993	1.07	0.48	0.83
1994	1.07	0.48	0.82
1995	1.08	0.48	0.82
1996	1.09	0.48	0.82
1997	1.10	0.48	0.82
1998	1.12	0.48	0.82
1999	1.13	0.48	0.82
2000	1.14	0.48	0.82
2001	1.16	0.48	0.82
2002	1.18	0.48	0.82
2003	1.19	0.48	0.82
2004	1.21	0.48	0.82
2005	1.23	0.48	0.82
2006	1.25	0.48	0.82
2007	1.27	0.48	0.82
2008	1.29	0.48	0.82
2009	1.31	0.48	0.82
2010	1.33	0.48	0.82

Total Costs by CF in 1991 $/MWh - Real Levelized by In-Service Date

	10% (4)	20% (5)	30% (6)	40% (7)	50% (8)	60% (9)	70% (10)	80% (11)	90% (12)	
DRI Mtn.1										
1991	309.88	161.70	112.30	87.61	72.79	62.91	55.85	50.56	46.44	1991
1996	310.22	162.03	112.64	87.94	73.12	63.25	56.19	50.90	46.78	1996
2001	310.86	162.67	113.28	88.58	73.76	63.89	56.83	51.54	47.42	2001
2006	311.69	163.51	114.11	89.42	74.60	64.72	57.66	52.37	48.25	2006
2010	312.43	164.25	114.86	90.16	75.34	65.46	58.41	53.11	49.00	2010
Powder River										
1991	304.38	156.20	106.81	82.11	67.29	57.41	50.36	45.06	40.95	1991
1996	304.38	156.20	106.81	82.11	67.29	57.41	50.36	45.06	40.95	1996
2001	304.38	156.20	106.81	82.11	67.29	57.41	50.36	45.06	40.95	2001
2006	304.38	156.20	106.81	82.11	67.29	57.41	50.36	45.06	40.95	2006
2010	304.38	156.20	106.81	82.11	67.29	57.41	50.36	45.06	40.95	2010
Utah										
1991	307.76	159.57	110.18	85.48	70.67	60.79	53.73	48.44	44.32	1991
1996	307.63	159.45	110.06	85.36	70.54	60.66	53.61	48.32	44.20	1996
2001	307.63	159.45	110.05	85.35	70.54	60.66	53.60	48.31	44.19	2001
2006	307.63	159.45	110.05	85.35	70.54	60.66	53.60	48.31	44.19	2006
2010	307.63	159.45	110.05	85.35	70.54	60.66	53.60	48.31	44.19	2010

GENERAL SCREENING ANALYSIS

GENERAL SCREENING ANALYSIS

The following graphs show cross-over points for various combinations of new resources. The cross-over point is the capacity factor at which one resource becomes a more cost effective choice than another resource. The graphs provide comparisons for different combinations of resources, for different inservice dates, and for different external cost levels. The four external cost levels, in $/ton, are as follows:

	SO2	NOx	TSP	CO2
Level 1	1000	100	200	5
Level 2	2000	4000	3000	0
Level 3	2000	4000	3000	10
Level 4	2000	4000	3000	30

The graphs are as follows:

For Geothermal, Hunter 4, and CCCT at 3 different levels of gas costs:
Total Estimated Costs with **1996** Inservice - No External Cost
Total Estimated Costs with **2001** Inservice - No External Cost
Total Estimated Costs with **2010** Inservice - No External Cost

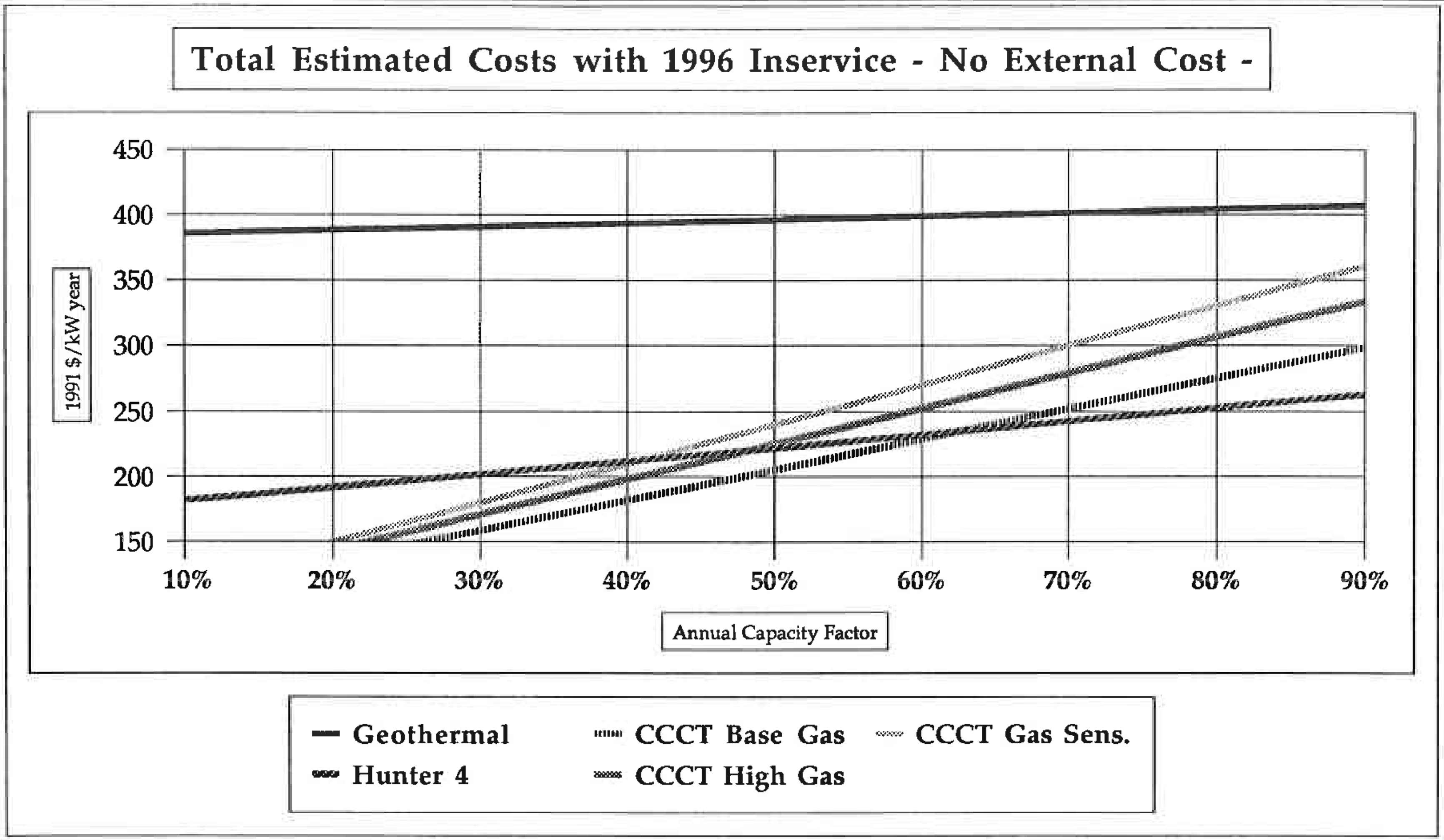
For Geothermal, Hunter 4, CCCT, Cogeneration, and Wind at 26% and 30% CF:
Total Estimated Costs with **1996** Inservice - No External Cost
Total Estimated Costs with **1996** Inservice - External Cost Level 1
Total Estimated Costs with **1996** Inservice - External Cost Level 2
Total Estimated Costs with **1996** Inservice - External Cost Level 3
Total Estimated Costs with **1996** Inservice - External Cost Level 4
Total Estimated Costs with **2001** Inservice - No External Cost
Total Estimated Costs with **2010** Inservice - No External Cost

Baseload Resources: **For CCCT, Hunter 4, Wyodak 2, Geothermal, AFB Coal, and IGCC Coal:**

Total Estimated Costs with **1996** Inservice - No External Cost
Total Estimated Costs with **1996** Inservice - External Cost Level 1
Total Estimated Costs with **1996** Inservice - External Cost Level 2
Total Estimated Costs with **1996** Inservice - External Cost Level 3
Total Estimated Costs with **1996** Inservice - External Cost Level 4
Total Estimated Costs with **2001** Inservice - No External Cost
Total Estimated Costs with **2001** Inservice - External Cost Level 1
Total Estimated Costs with **2001** Inservice - External Cost Level 2
Total Estimated Costs with **2001** Inservice - External Cost Level 3
Total Estimated Costs with **2001** Inservice - External Cost Level 4
Total Estimated Costs with **2010** Inservice - No External Cost
Total Estimated Costs with **2010** Inservice - External Cost Level 1
Total Estimated Costs with **2010** Inservice - External Cost Level 2
Total Estimated Costs with **2010** Inservice - External Cost Level 3
Total Estimated Costs with **2010** Inservice - External Cost Level 4

Peaking Resources: **For (single cycle) CT, CCCT, and Luz Solar at two different cost levels:**

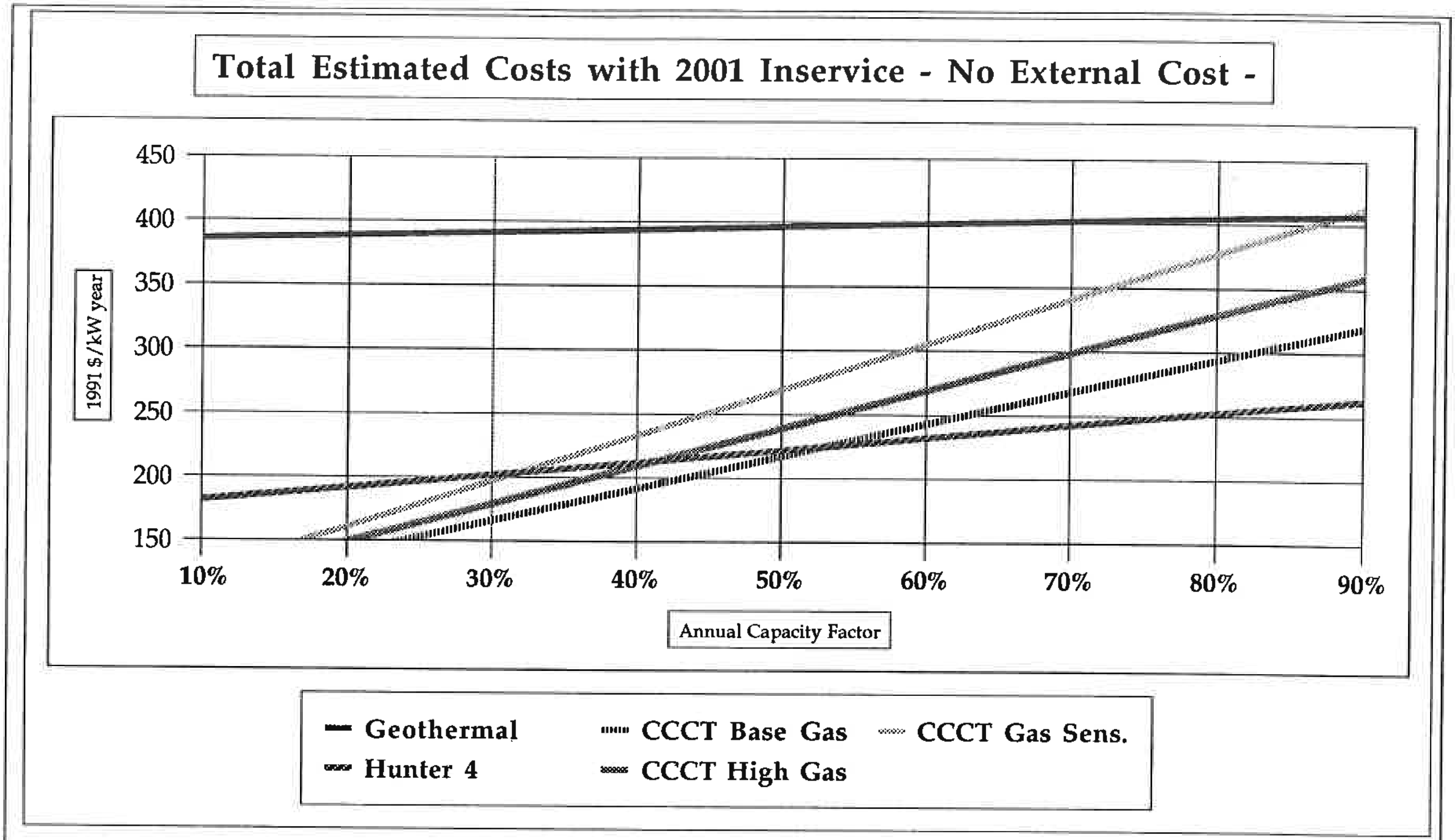
Total Estimated Costs with **1996** Inservice - No External Cost
Total Estimated Costs with **1996** Inservice - External Cost Level 1
Total Estimated Costs with **1996** Inservice - External Cost Level 2
Total Estimated Costs with **1996** Inservice - External Cost Level 3
Total Estimated Costs with **1996** Inservice - External Cost Level 4
Total Estimated Costs with **2001** Inservice - No External Cost
Total Estimated Costs with **2001** Inservice - External Cost Level 1
Total Estimated Costs with **2001** Inservice - External Cost Level 2
Total Estimated Costs with **2001** Inservice - External Cost Level 3
Total Estimated Costs with **2001** Inservice - External Cost Level 4
Total Estimated Costs with **2010** Inservice - No External Cost
Total Estimated Costs with **2010** Inservice - External Cost Level 1
Total Estimated Costs with **2010** Inservice - External Cost Level 2
Total Estimated Costs with **2010** Inservice - External Cost Level 3
Total Estimated Costs with **2010** Inservice - External Cost Level 4



Total Estimated Costs with 1996 Inservice - No External Cost - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	386	388	391	394	396	399	402	404	407
Hunter 4	181	191	201	212	222	232	242	252	263
CCCT - Base Gas	112	135	159	182	205	228	252	275	298
CCCT - High Gas	116	143	170	198	225	252	279	306	334
CCCT - High Gas Sens.	119	149	179	210	240	270	300	331	361

Note : Real Levelized 1991 $'s/kW year. No External Costs.

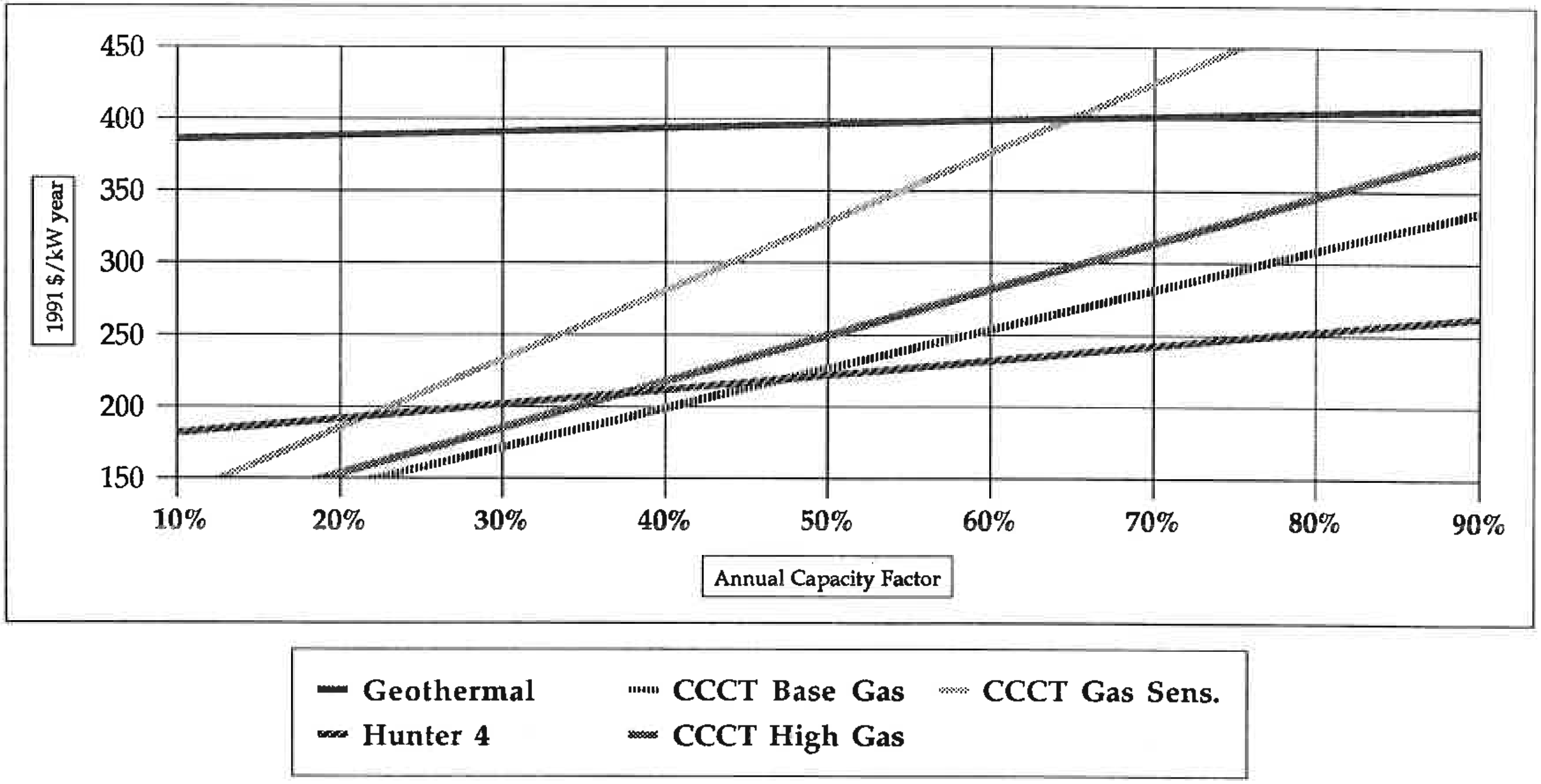


Total Estimated Costs with 2001 Inservice - No External Cost - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	386	388	391	394	396	399	402	404	407
Hunter 4	181	191	201	212	222	232	242	252	263
CCCT - Base Gas	114	140	166	191	217	243	268	294	320
CCCT - High Gas	119	149	179	209	239	269	299	329	359
CCCT - High Gas Sens.	125	161	197	233	269	305	341	377	413

Note : Real Levelized 1991 $'s/kW year. No External Costs.

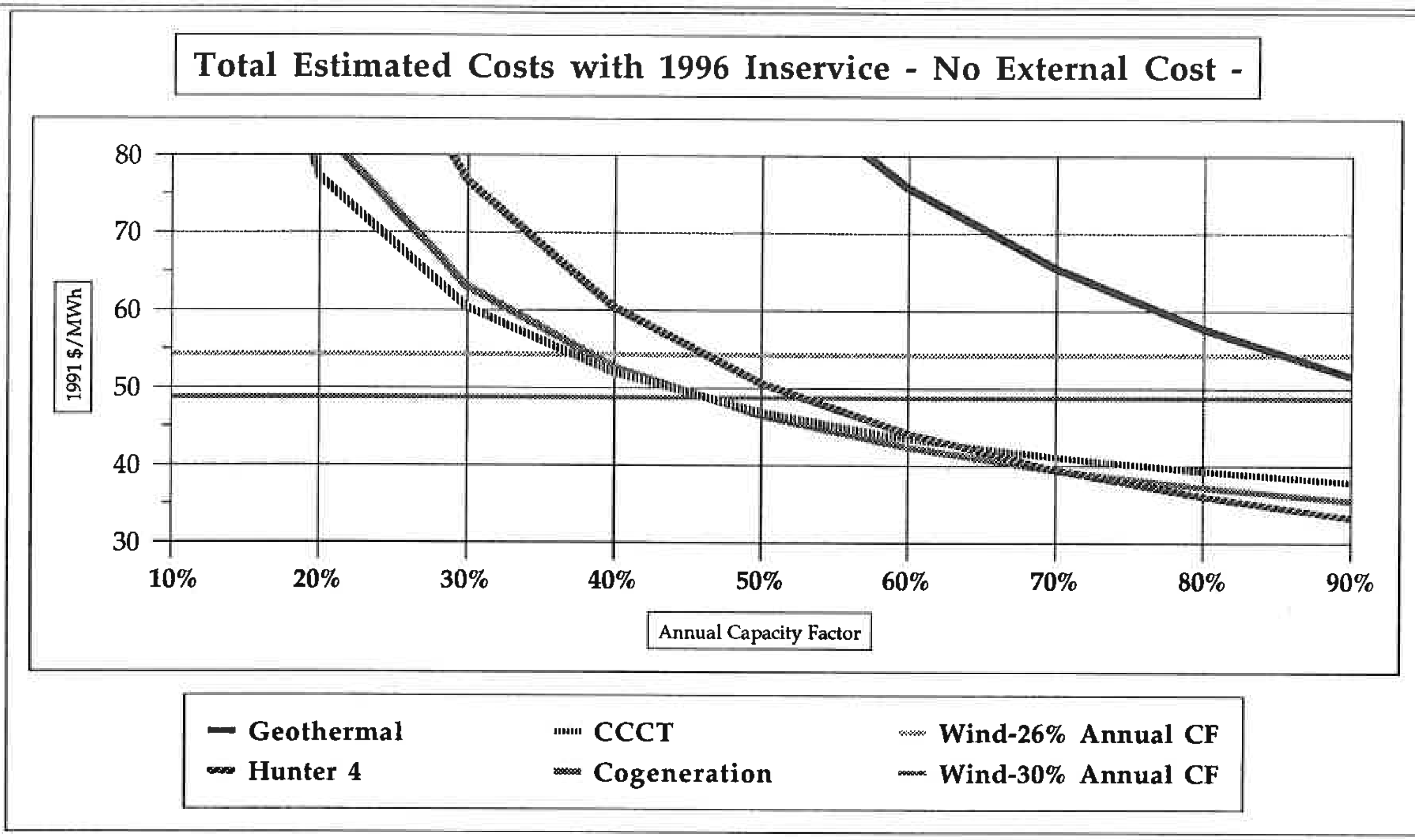
Total Estimated Costs with 2010 Inservice - No External Cost -



Total Estimated Costs with 2010 Inservice - No External Cost - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	386	388	391	394	396	399	402	404	407
Hunter 4	181	191	201	212	222	232	242	252	263
CCCT - Base Gas	116	144	171	199	226	254	281	309	336
CCCT - High Gas	121	153	185	217	249	282	314	346	378
CCCT - High Gas Sens.	137	185	233	281	329	377	425	473	521

Note : Real Levelized 1991 $'s/kW year. No External Costs.

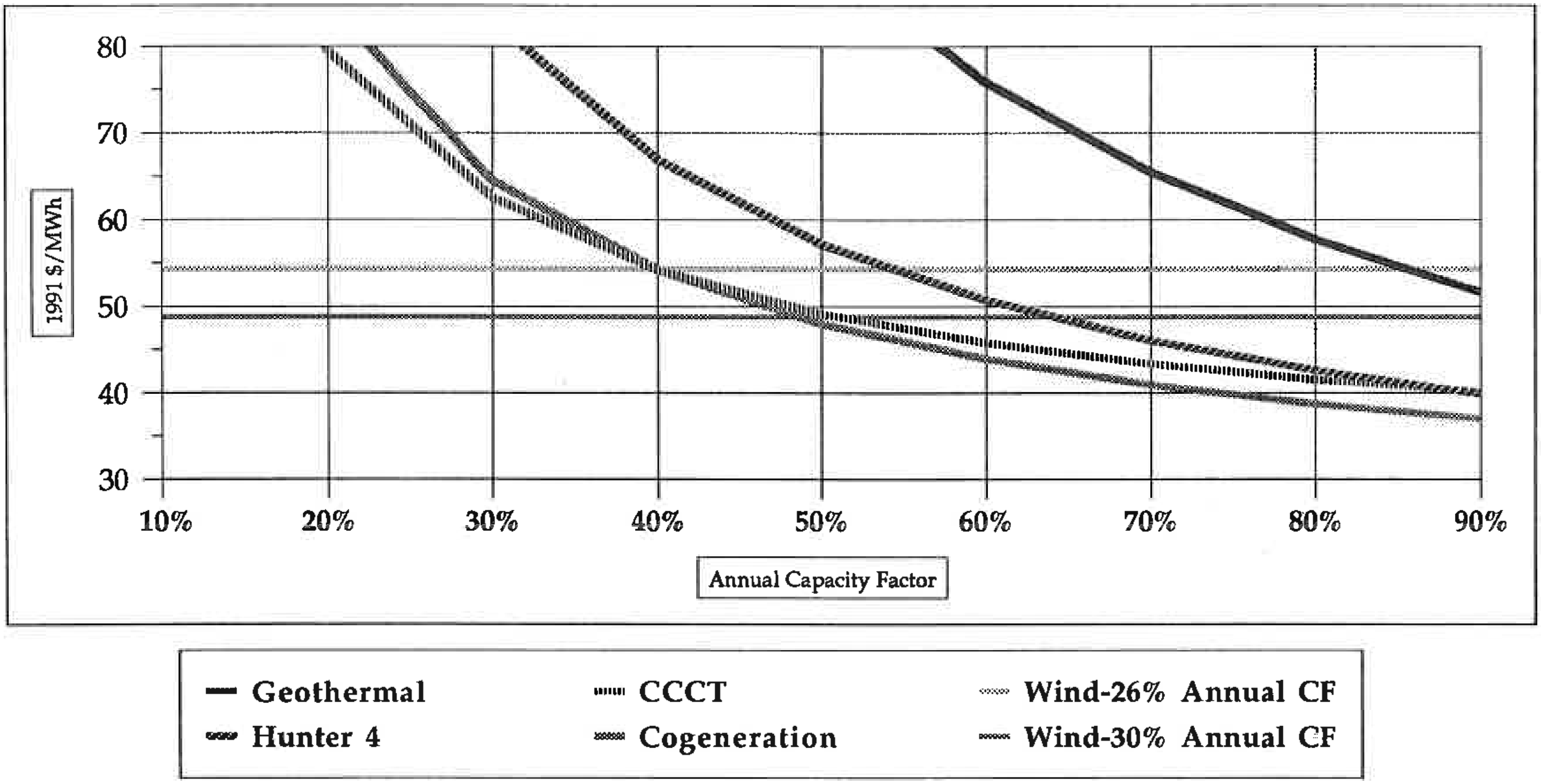


Total Estimated Costs with 1996 Inservice - No External Cost - in Total 1991$/MWh

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	440	222	149	112	90	76	65	58	52
Hunter 4	207	109	77	60	51	44	39	36	33
CCCT	128	77	60	52	47	43	41	39	38
Cogeneration	145	84	63	53	46	42	39	37	35
Wind-26% Annual CF	54	54	54	54	54	54	54	54	54
Wind-30% Annual CF	49	49	49	49	49	49	49	49	49

Note : Real Levelized 1991 $'s/MWh, Base Gas Assumptions, No External Costs.

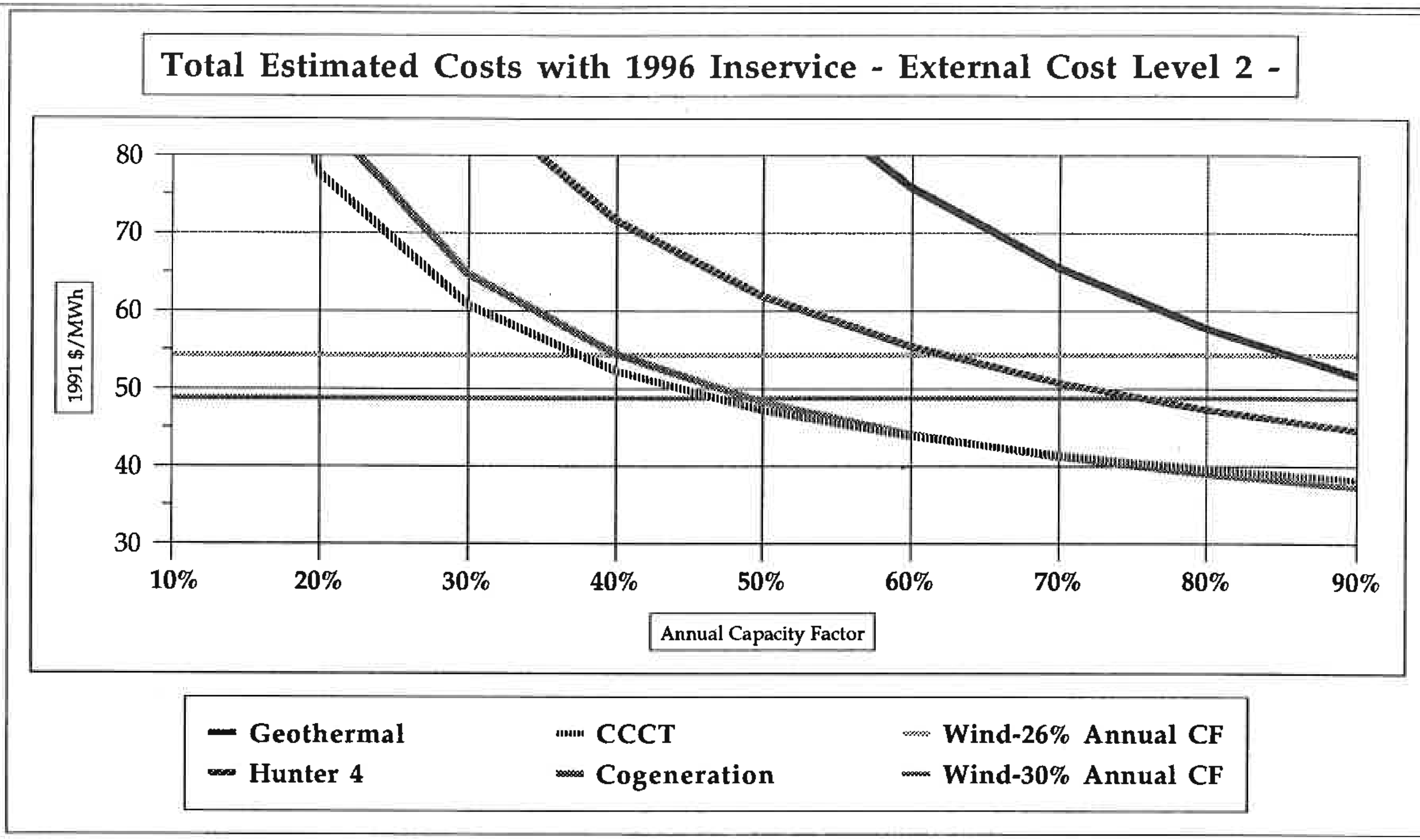
Total Estimated Costs with 1996 Inservice - External Cost Level 1 -



Total Estimated Costs with 1996 Inservice - External Cost Level 1 - in Total 1991$/MWh

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	440	222	149	112	90	76	65	58	52
Hunter 4	213	116	83	67	57	51	46	43	40
CCCT	130	79	63	54	49	46	43	41	40
Cogeneration	147	85	64	54	48	44	41	39	37
Wind-26% Annual CF	54	54	54	54	54	54	54	54	54
Wind-30% Annual CF	49	49	49	49	49	49	49	49	49

Note : Real Levelized 1991 $'s/MWh, Base Gas Assumptions, External Cost Level 1.

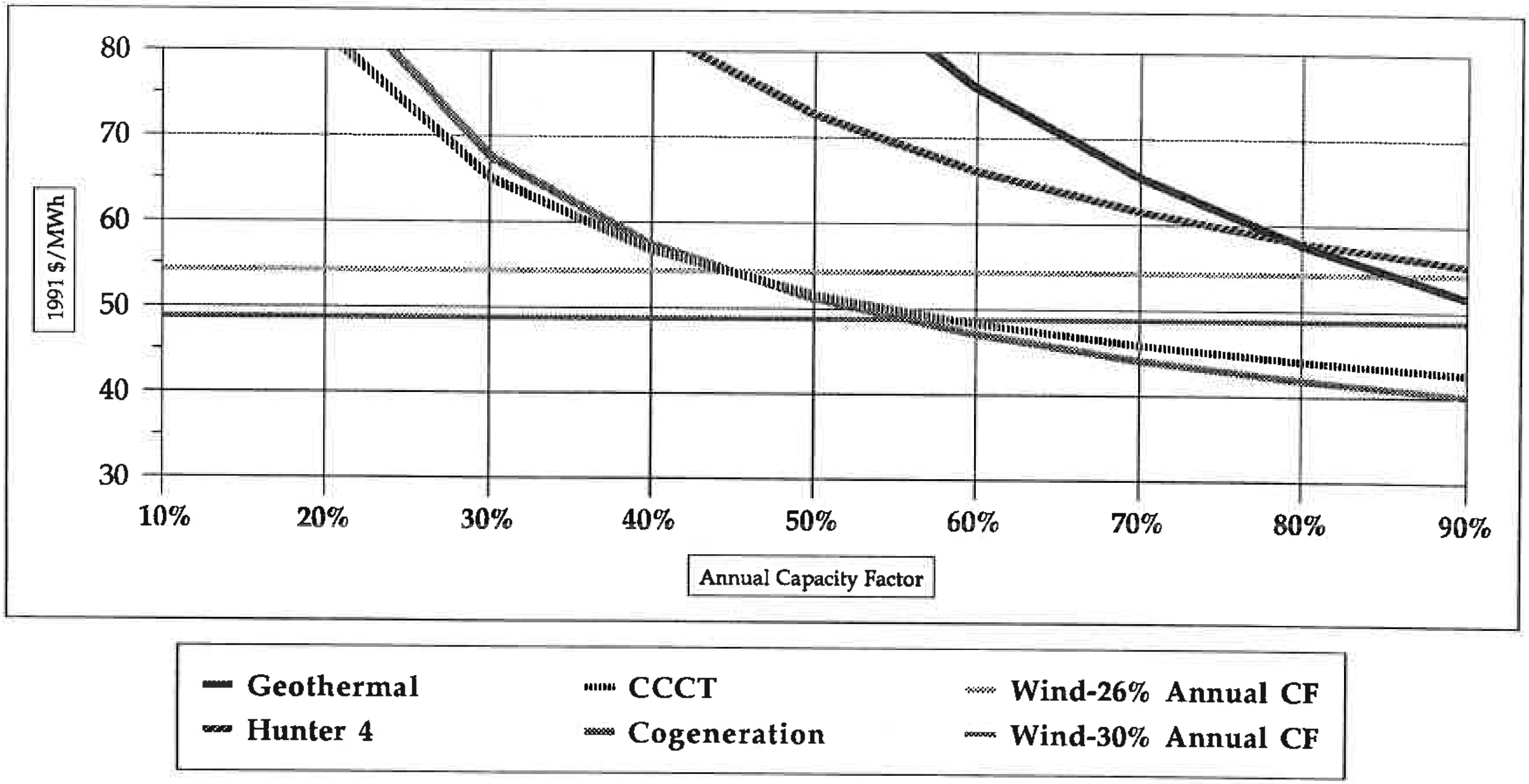


Total Estimated Costs with 1996 Inservice - External Cost Level 2 - in Total 1991$/MWh

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	440	222	149	112	90	76	65	58	52
Hunter 4	218	120	88	72	62	55	51	47	45
CCCT	128	78	61	52	47	44	41	40	38
Cogeneration	147	85	65	54	48	44	41	39	37
Wind-26% Annual CF	54	54	54	54	54	54	54	54	54
Wind-30% Annual CF	49	49	49	49	49	49	49	49	49

Note : Real Levelized 1991 $'s/MWh, Base Gas Assumptions, External Cost Level 2.

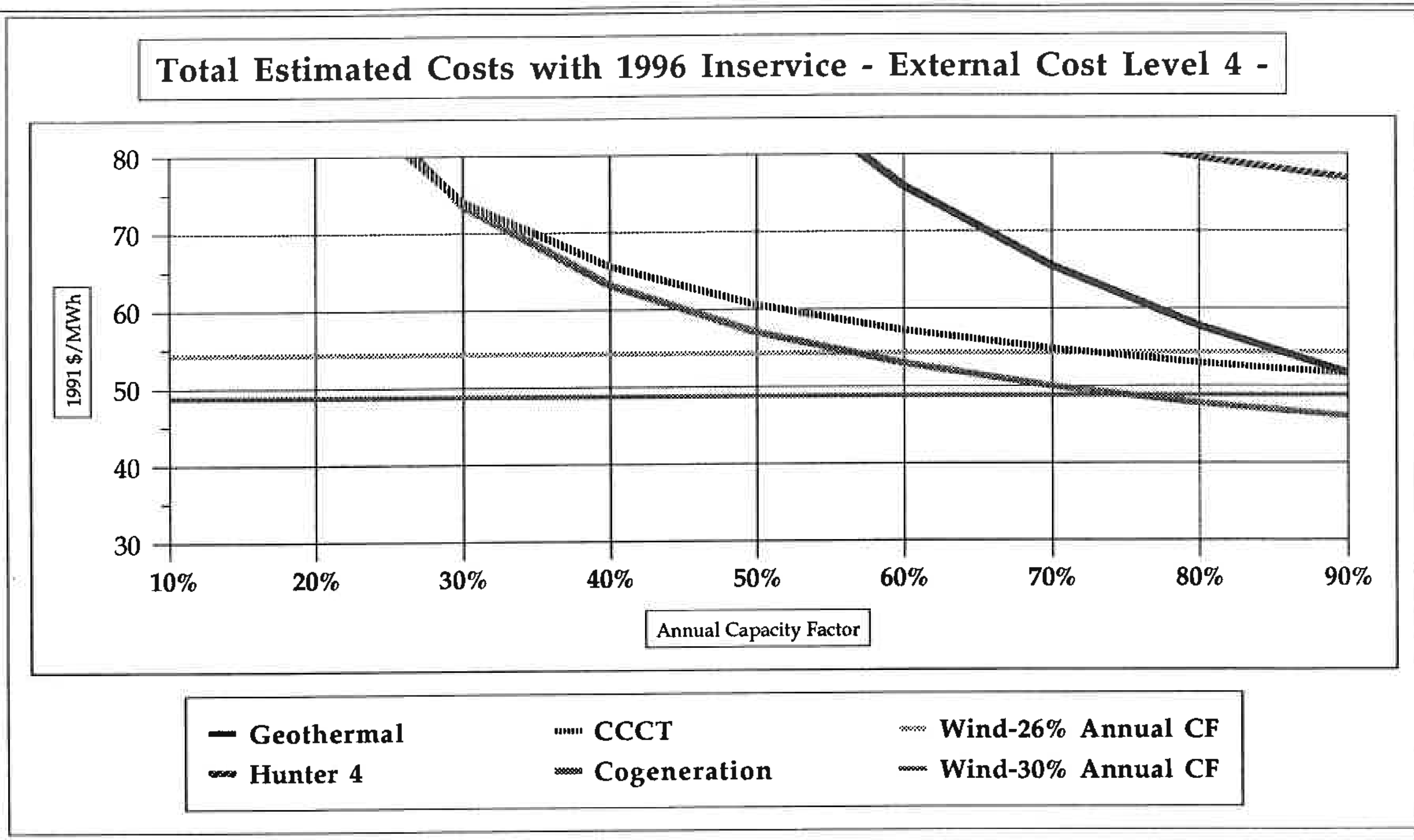
Total Estimated Costs with 1996 Inservice - External Cost Level 3 -



Total Estimated Costs with 1996 Inservice - External Cost Level 3 - in Total 1991$/MWh

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	440	222	149	112	90	76	65	58	52
Hunter 4	229	131	99	82	73	66	61	58	55
CCCT	133	82	65	57	52	48	46	44	43
Cogeneration	150	88	68	57	51	47	44	42	40
Wind-26% Annual CF	54	54	54	54	54	54	54	54	54
Wind-30% Annual CF	49	49	49	49	49	49	49	49	49

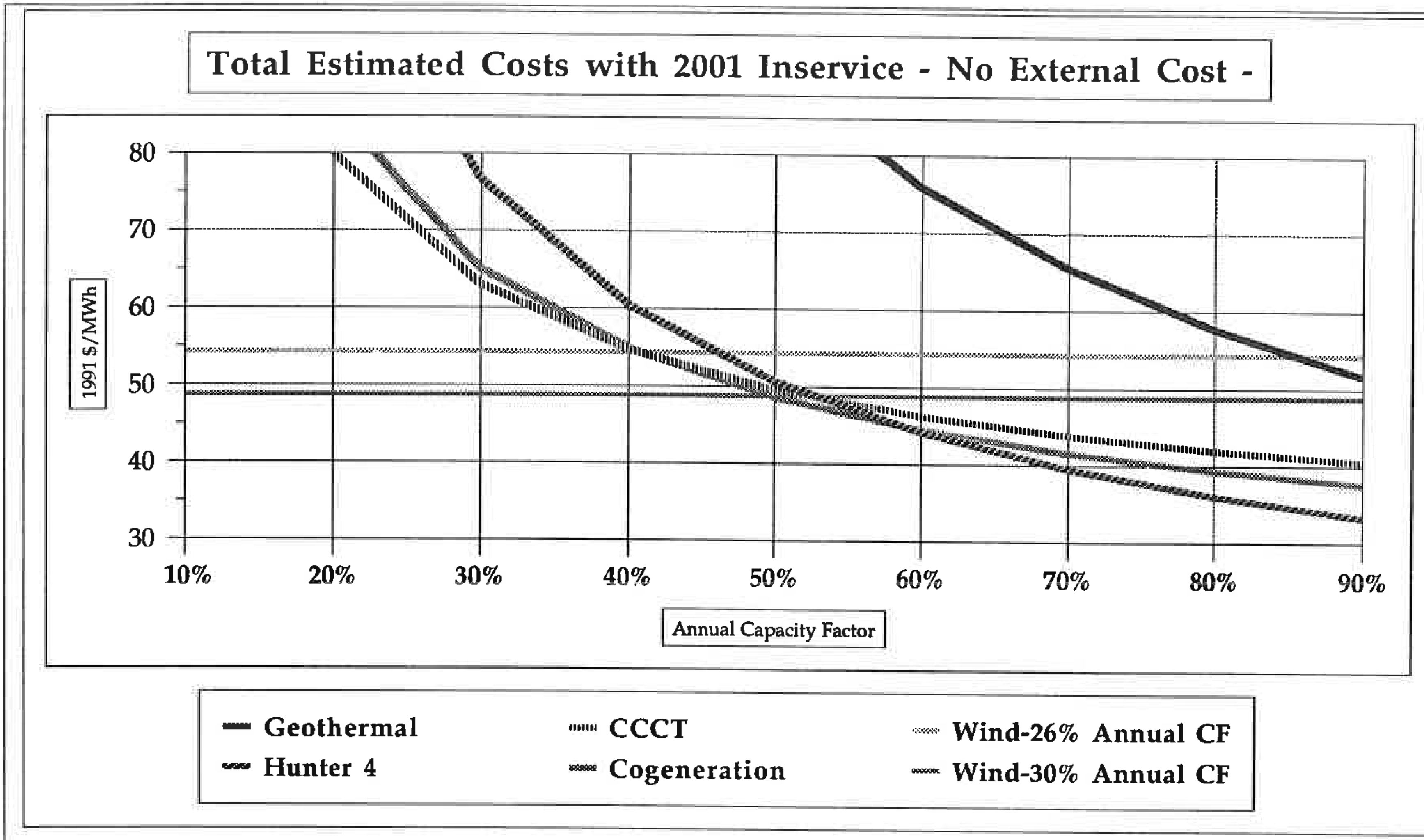
Note : Real Levelized 1991 $'s/MWh, Base Gas Assumptions,External Cost Level 3.



Total Estimated Costs with 1996 Inservice - External Cost Level 4 - in Total 1991$/MWh

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	440	222	149	112	90	76	65	58	52
Hunter 4	250	153	120	104	94	88	83	80	77
CCCT	141	91	74	66	61	57	55	53	52
Cogeneration	156	94	74	63	57	53	50	48	46
Wind-26% Annual CF	54	54	54	54	54	54	54	54	54
Wind-30% Annual CF	49	49	49	49	49	49	49	49	49

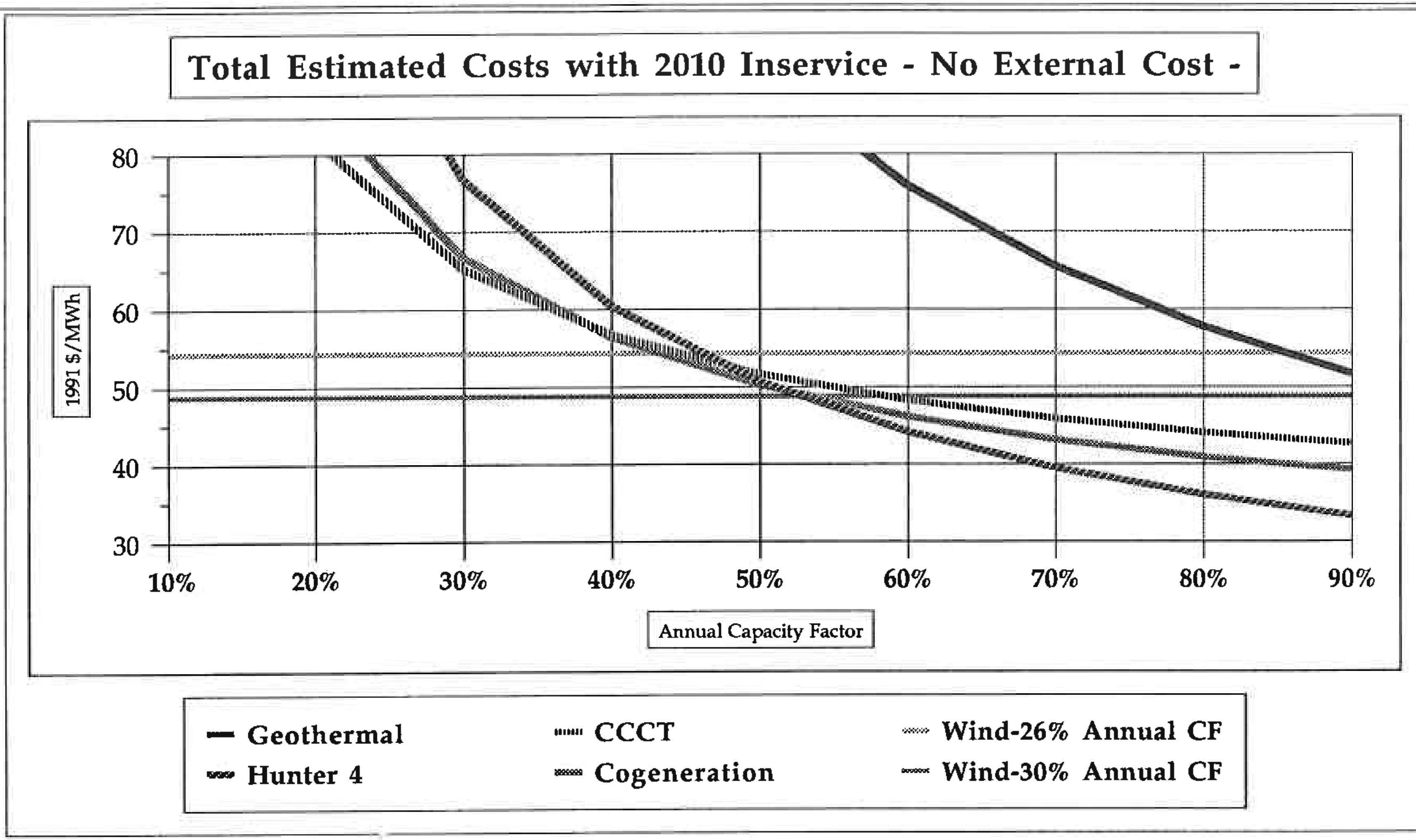
Note : Real Levelized 1991 $'s/MWh, Base Gas Assumptions, External Cost Level 4.



Total Estimated Costs with 2001 Inservice - No External Cost - in Total 1991$/MWh

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	440	222	149	112	90	76	65	58	52
Hunter 4	207	109	77	60	51	44	39	36	33
CCCT	130	80	63	55	50	46	44	42	41
Cogeneration	148	86	65	55	49	44	41	39	38
Wind-26% Annual CF	54	54	54	54	54	54	54	54	54
Wind-30% Annual CF	49	49	49	49	49	49	49	49	49

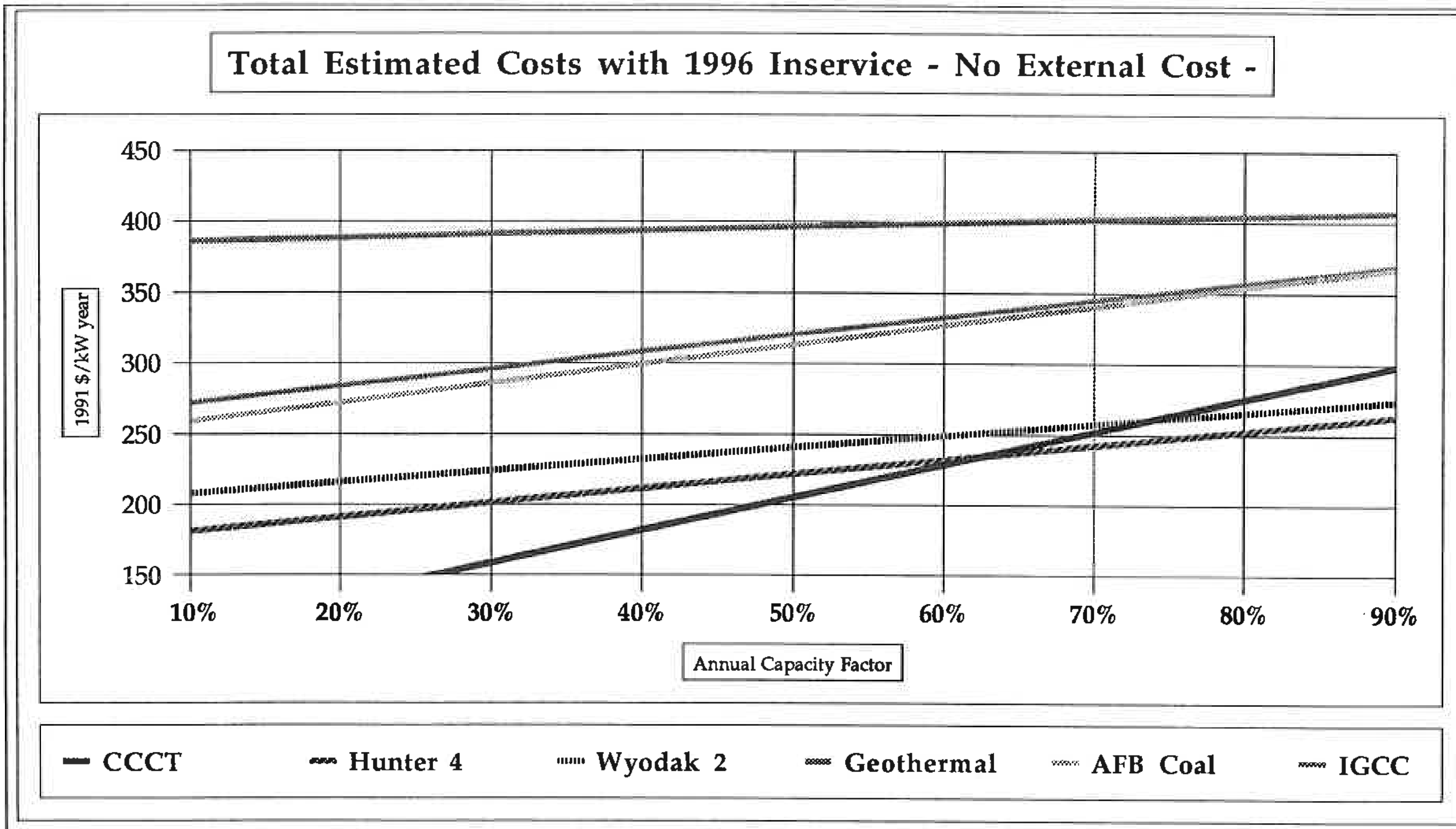
Note : Real Levelized 1991 $'s/MWh, Base Gas Assumptions, No External Costs.



Total Estimated Costs with 2010 Inservice - No External Cost - in Total 1991$/MWh

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
Geothermal	440	222	149	112	90	76	65	58	52
Hunter 4	207	109	77	60	51	44	39	36	33
CCCT	133	82	65	57	52	48	46	44	43
Cogeneration	149	87	67	56	50	46	43	41	39
Wind-26% Annual CF	54	54	54	54	54	54	54	54	54
Wind-30% Annual CF	49	49	49	49	49	49	49	49	49

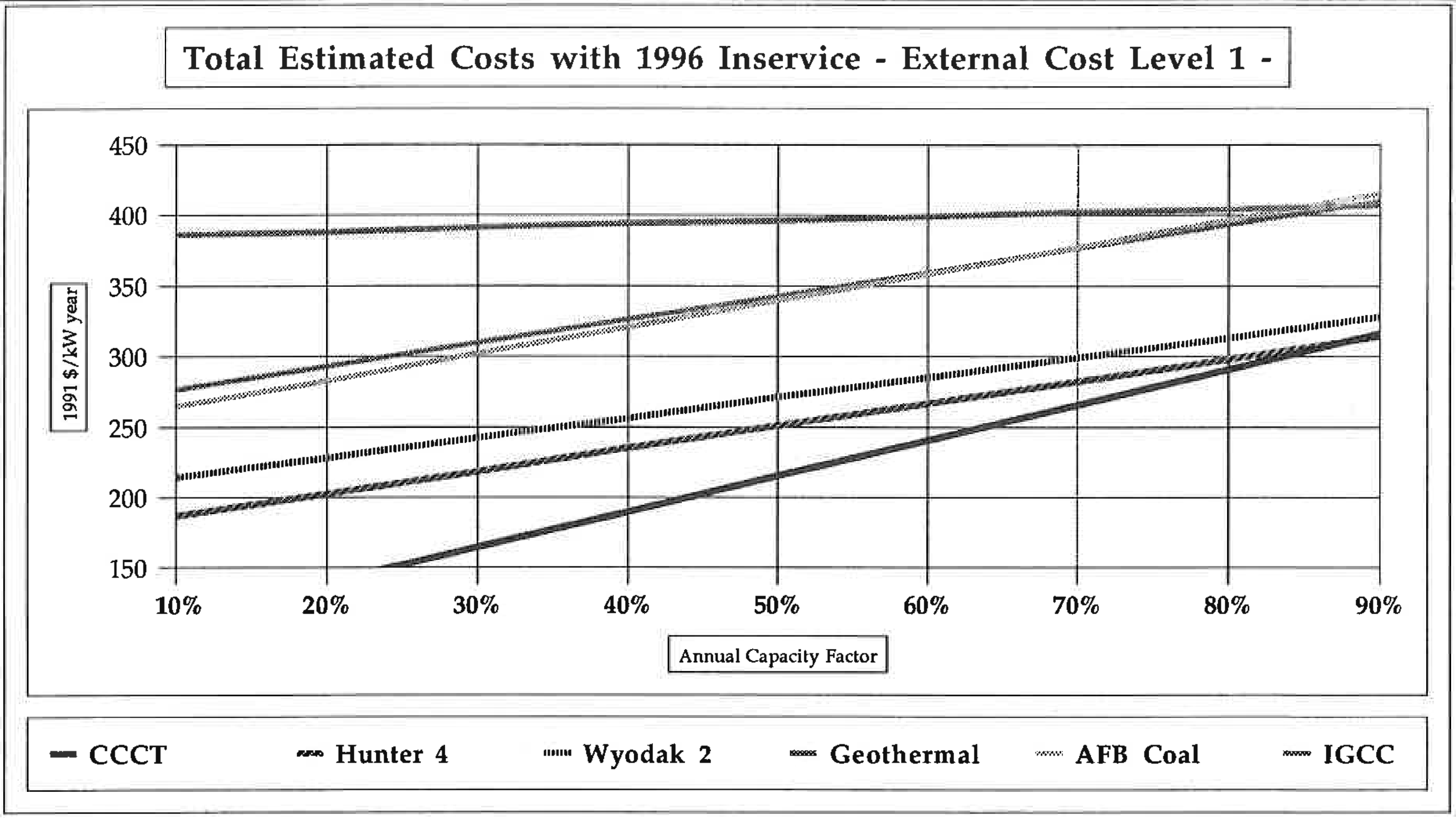
Note : Real Levelized 1991 $'s/MWh, Base Gas Assumptions, No External Costs.



Total Estimated Costs with 1996 Inservice - No External Cost - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	112	135	159	182	205	228	252	275	298
Hunter 4	181	191	201	212	222	232	242	252	263
Wyodak 2	208	216	224	232	241	249	257	265	274
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	259	272	286	299	313	326	340	354	367
IGCC	272	284	296	308	320	332	345	357	369

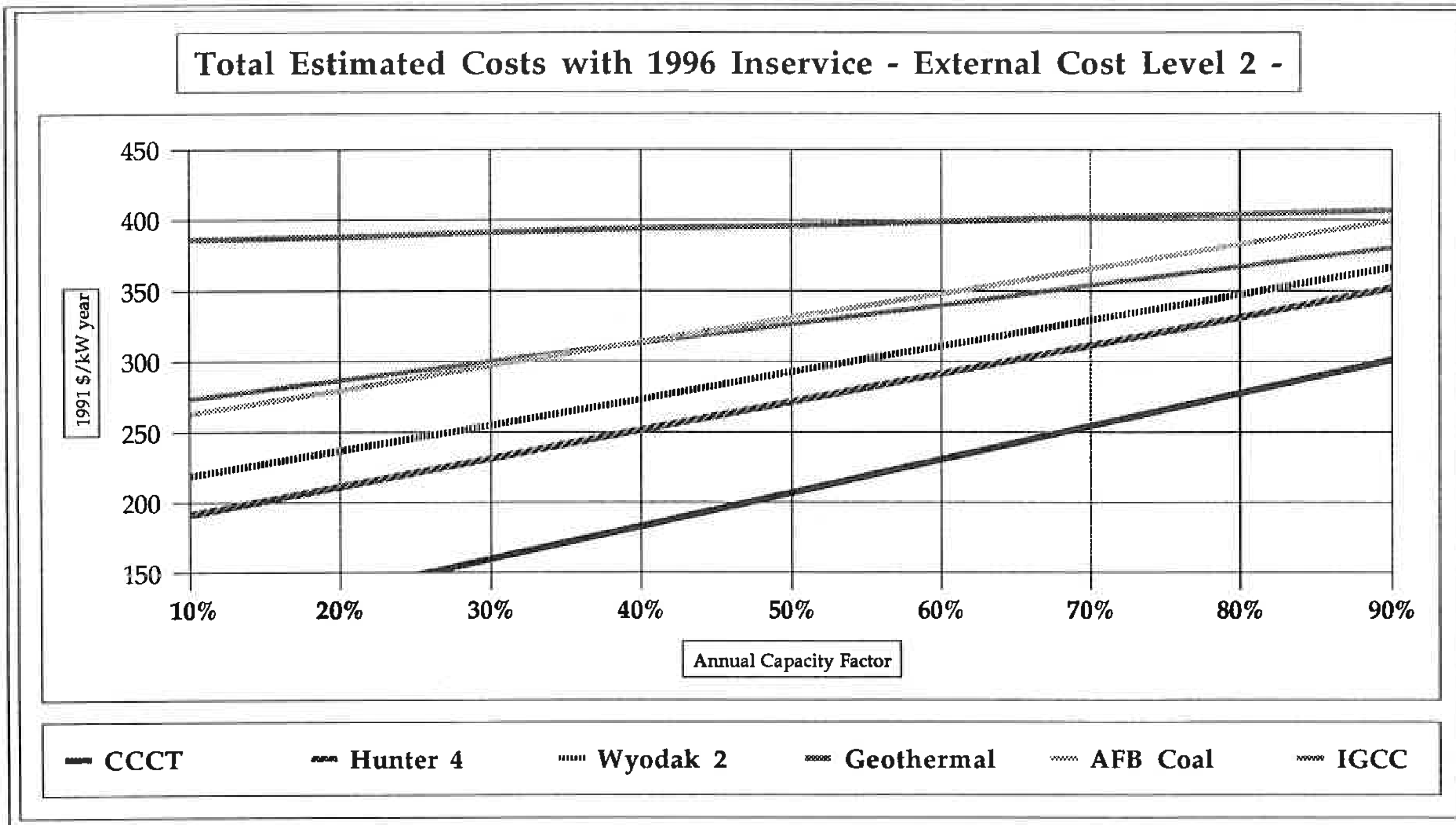
Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, No External Costs



Total Estimated Costs with 1996 Inservice - External Cost Level 1 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	114	139	164	190	215	240	266	291	316
Hunter 4	187	202	218	235	251	266	282	298	314
Wyodak 2	214	228	242	256	271	285	299	313	328
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	264	283	302	320	340	358	377	396	415
IGCC	276	293	309	326	342	359	376	393	409

Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 1.

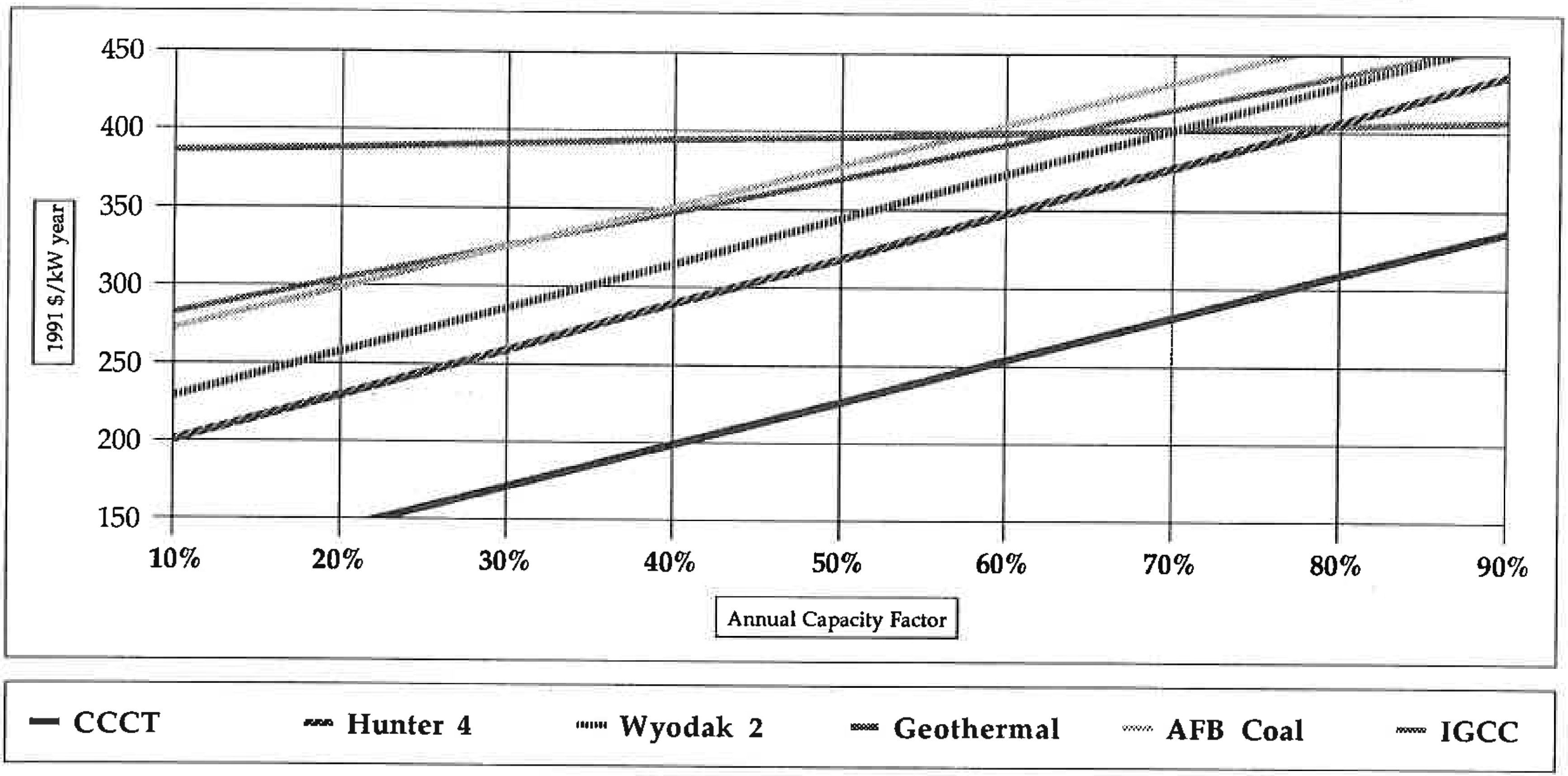


Total Estimated Costs with 1996 Inservice - External Cost Level 2 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	112	136	159	183	207	230	254	277	301
Hunter 4	191	211	231	251	271	291	311	331	352
Wyodak 2	218	237	255	273	292	311	329	347	366
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	263	279	297	313	331	348	365	383	399
IGCC	273	286	300	313	326	339	354	367	380

Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 2.

Total Estimated Costs with 1996 Inservice - External Cost Level 3 -

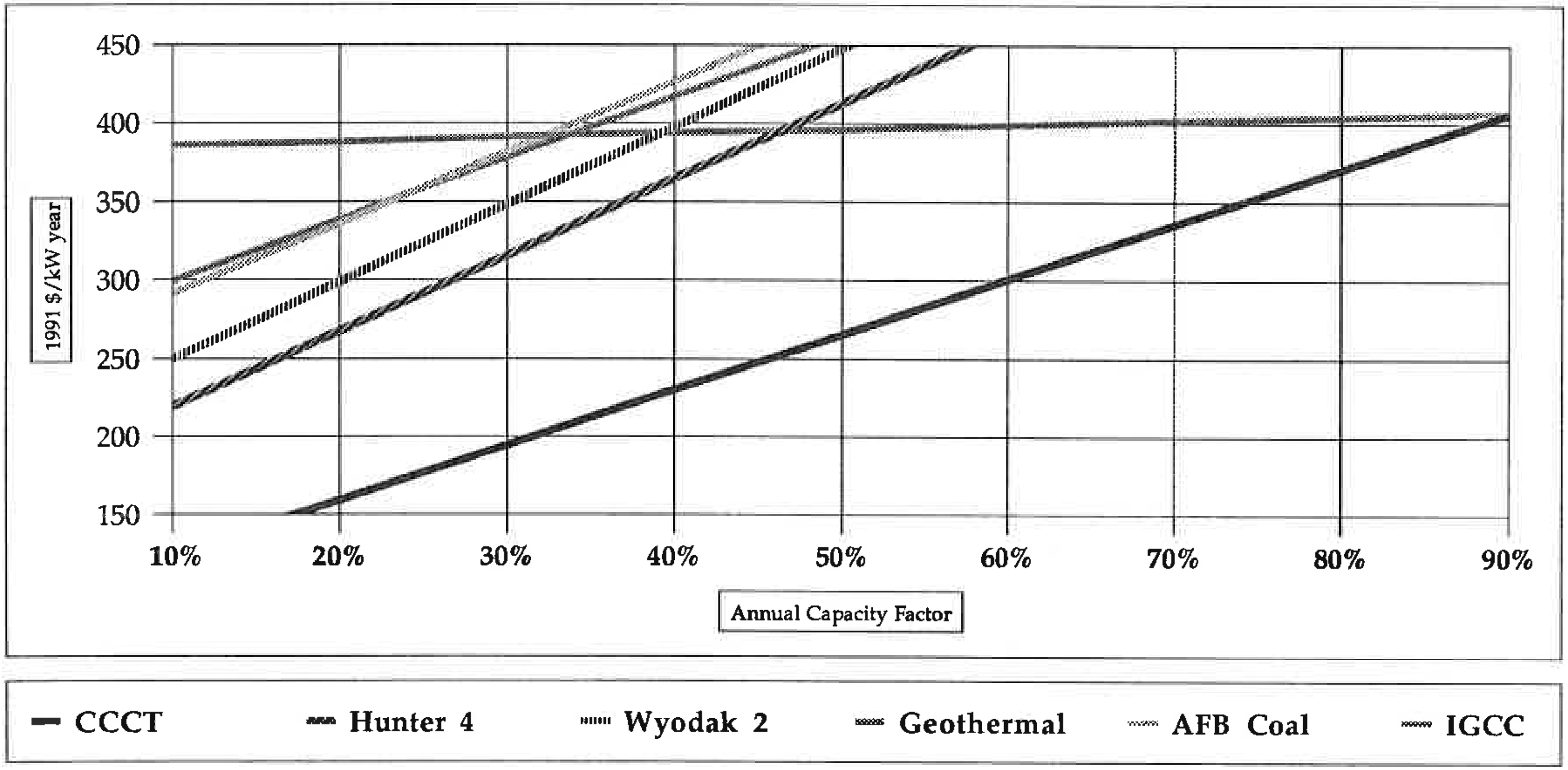


Total Estimated Costs with 1996 Inservice - External Cost Level 3 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	116	144	171	199	226	254	281	309	336
Hunter 4	200	230	259	289	318	348	377	406	436
Wyodak 2	229	257	286	314	344	373	401	430	460
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	272	298	325	351	378	404	431	458	484
IGCC	282	304	326	348	370	391	414	436	458

Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 3.

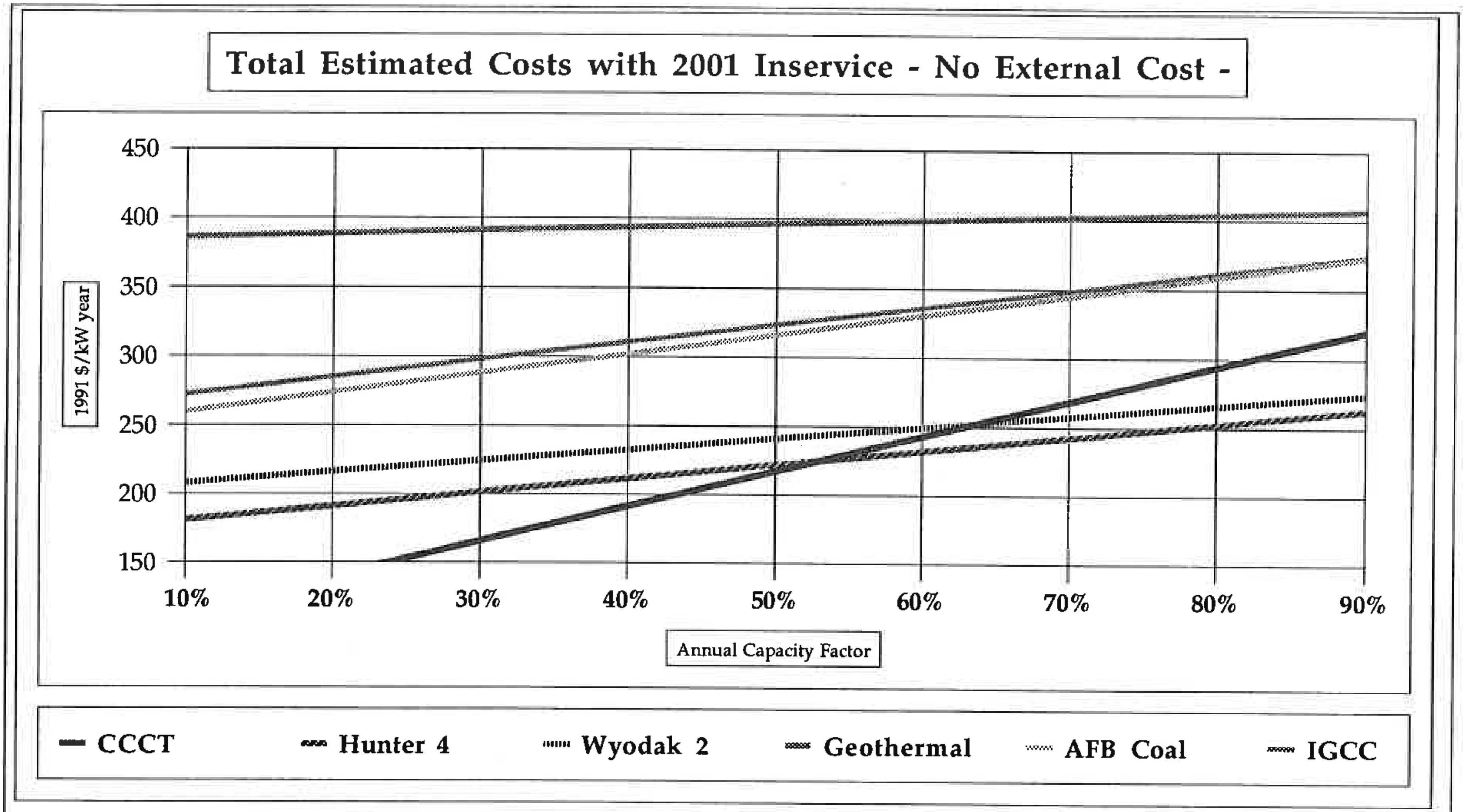
Total Estimated Costs with 1996 Inservice - External Cost Level 4 -



Total Estimated Costs with 1996 Inservice - External Cost Level 4 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	124	159	195	230	265	300	336	371	406
Hunter 4	219	267	315	364	413	461	509	557	606
Wyodak 2	249	299	348	397	448	497	546	596	646
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	291	336	382	426	472	517	563	609	654
IGCC	299	338	378	417	456	495	536	575	614

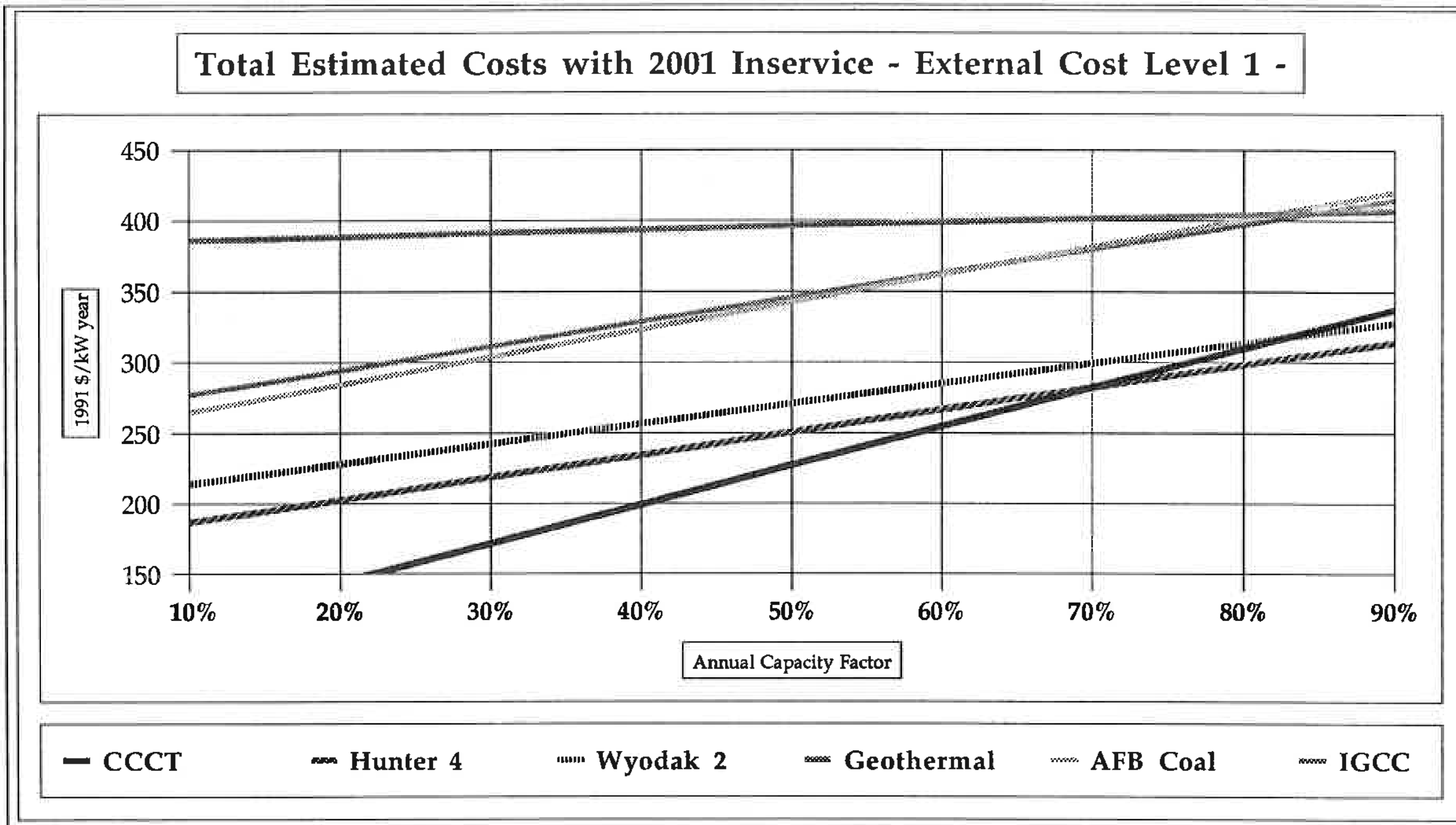
Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 4.



Total Estimated Costs with 2001 Inservice - No External Cost - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	114	140	166	191	217	243	268	294	320
Hunter 4	181	191	201	212	222	232	242	252	263
Wyodak 2	208	216	224	232	241	249	257	265	274
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	259	273	288	302	316	330	344	358	372
IGCC	272	285	298	310	323	336	348	361	374

Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, No External Costs.

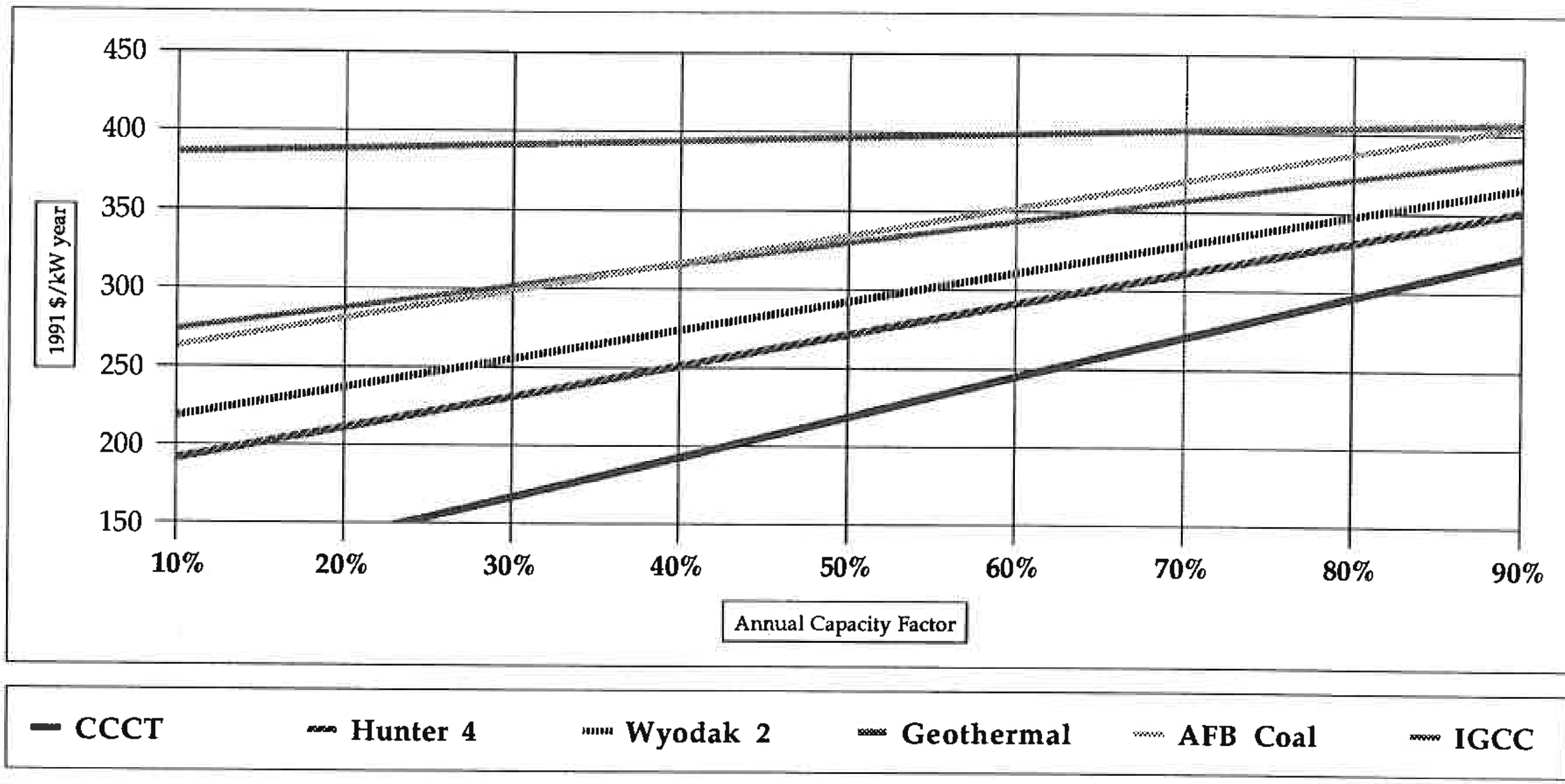


Total Estimated Costs with 2001 Inservice - External Cost Level 1 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	116	144	172	199	227	254	282	310	337
Hunter 4	187	203	218	234	250	266	282	298	314
Wyodak 2	214	228	242	256	271	285	299	313	328
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	265	284	303	323	342	362	381	401	420
IGCC	277	294	311	328	346	363	380	397	414

Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 1.

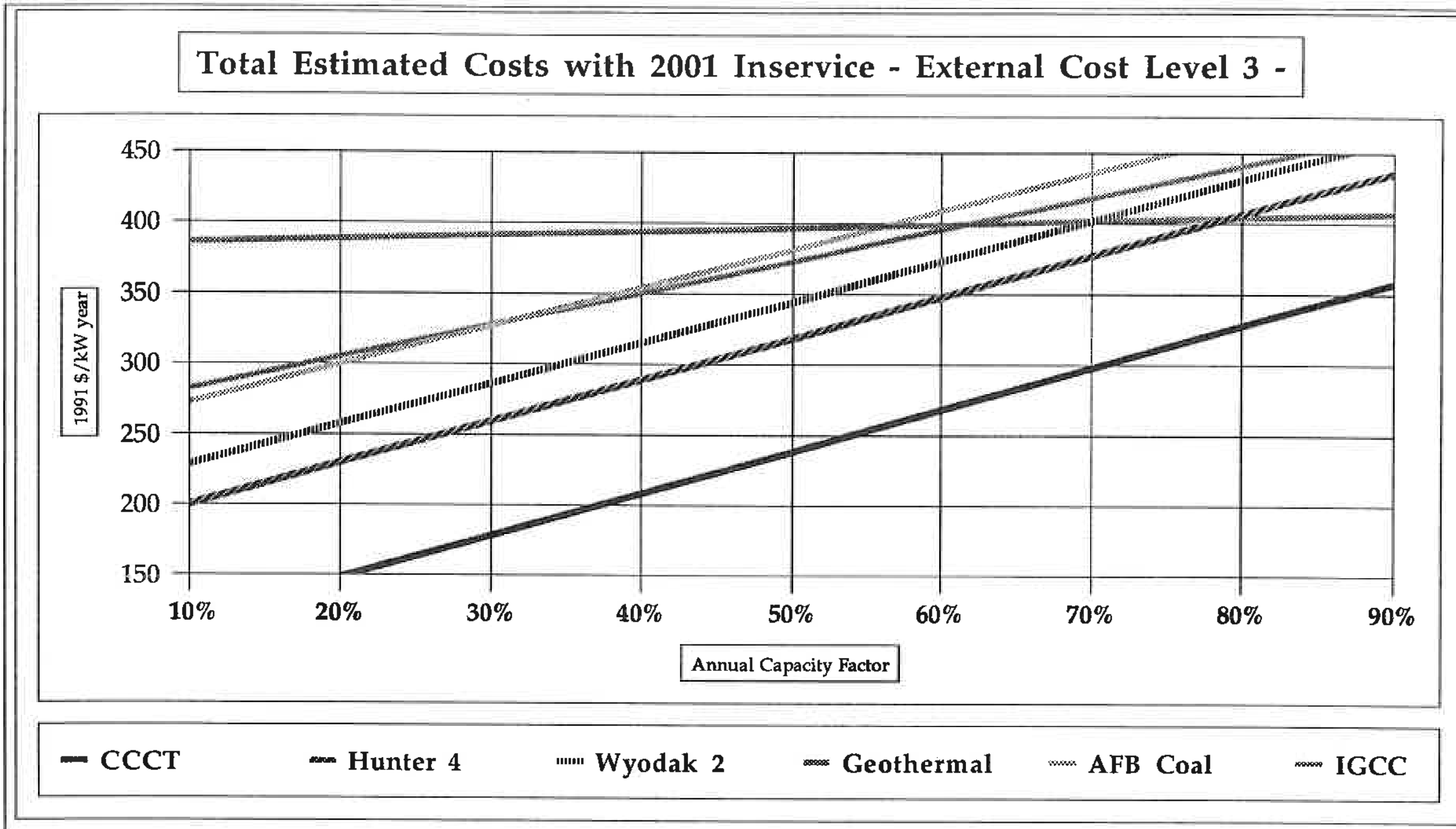
Total Estimated Costs with 2001 Inservice - External Cost Level 2 -



Total Estimated Costs with 2001 Inservice - External Cost Level 2 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	115	141	167	193	218	244	270	296	322
Hunter 4	191	211	231	251	271	291	311	331	351
Wyodak 2	218	236	255	273	292	311	329	348	366
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	263	281	298	316	334	352	369	387	405
IGCC	274	287	301	315	329	343	357	371	385

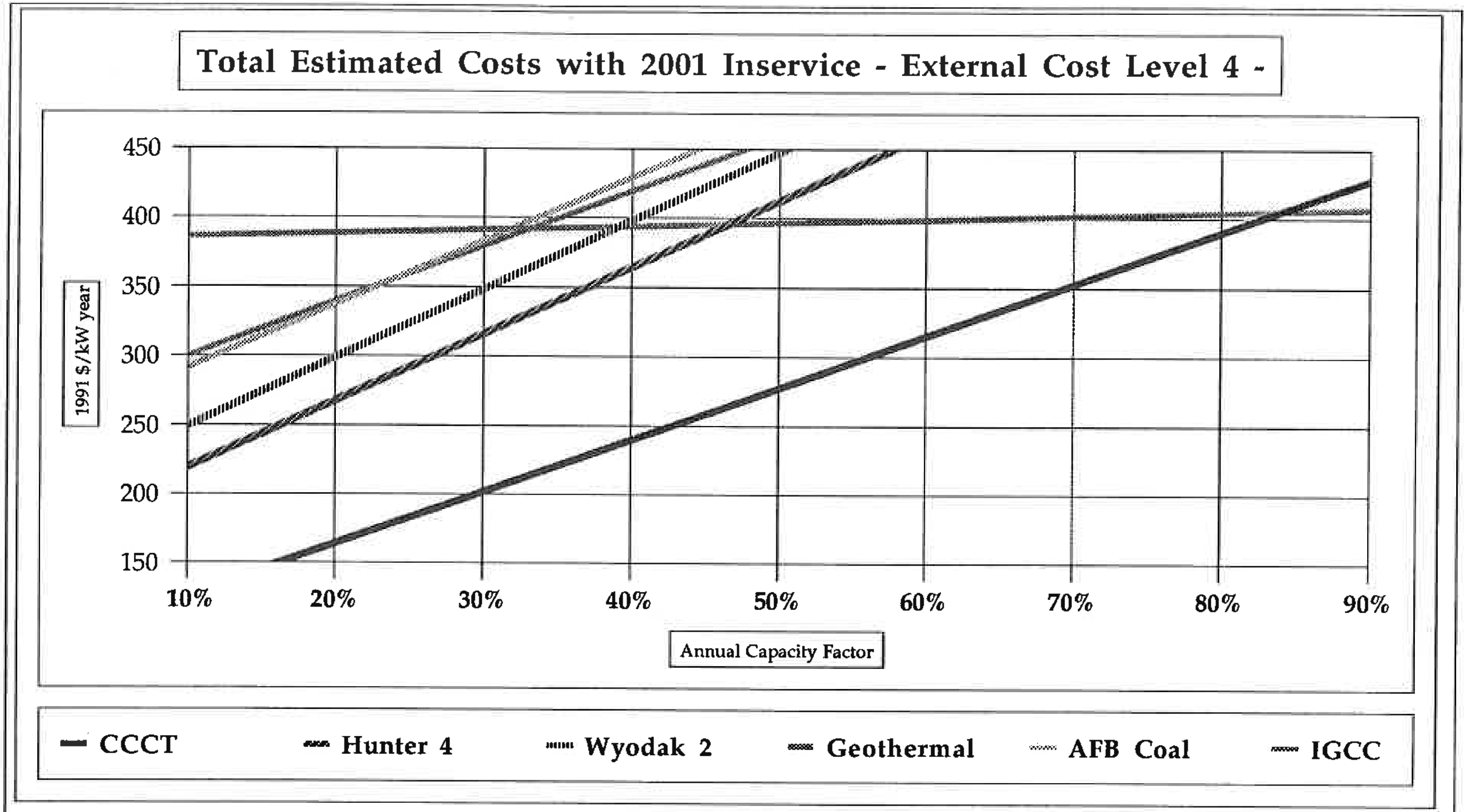
Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 2.



Total Estimated Costs with 2001 Inservice - External Cost Level 3 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	118	148	178	208	238	268	298	327	357
Hunter 4	200	230	259	289	318	348	377	406	436
Wyodak 2	228	257	286	315	344	373	402	430	459
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	272	299	327	354	381	408	435	462	490
IGCC	282	305	327	350	373	395	418	440	463

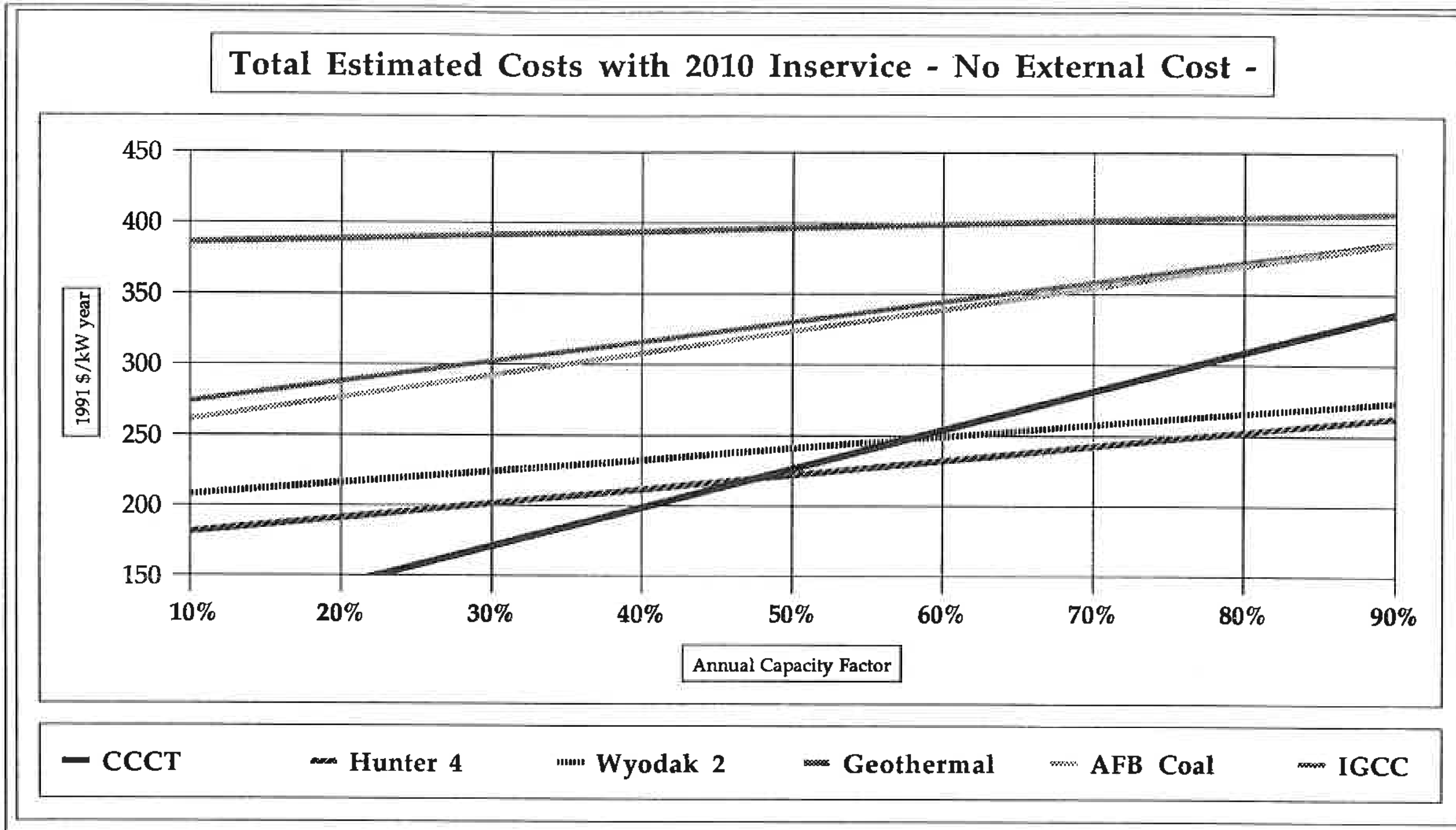
Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 3.



Total Estimated Costs with 2001 Inservice - External Cost Level 4 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	126	164	202	239	277	315	352	390	428
Hunter 4	219	267	316	364	412	461	509	557	605
Wyodak 2	249	299	348	398	447	497	547	596	646
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	291	337	383	429	475	521	567	613	659
IGCC	300	339	379	419	459	499	539	579	619

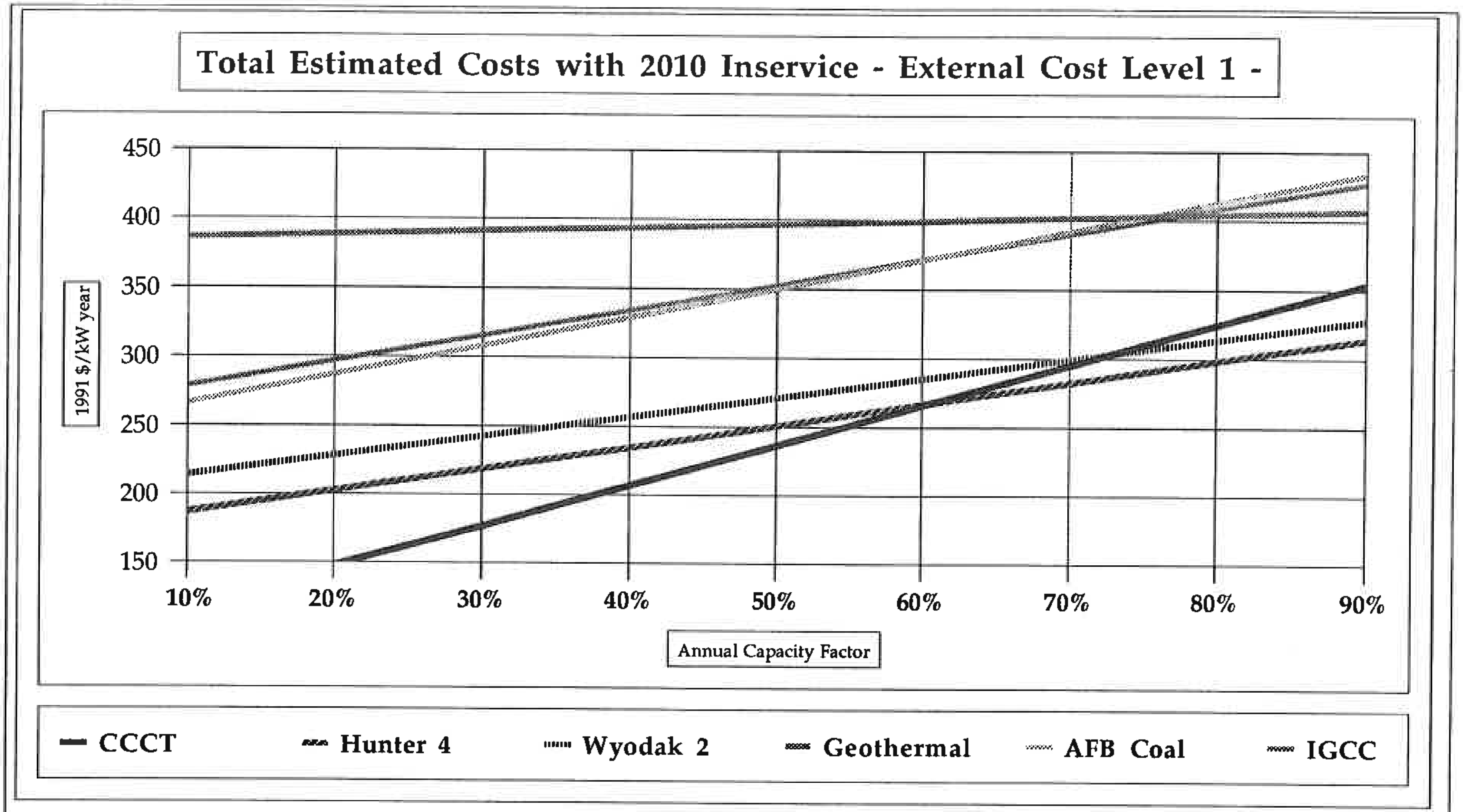
Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 4.



Total Estimated Costs with 2010 Inservice - No External Cost - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	116	144	171	199	226	254	281	309	336
Hunter 4	181	191	201	212	222	232	242	252	263
Wyodak 2	208	216	224	232	241	249	257	265	274
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	261	276	292	308	323	339	354	370	386
IGCC	274	288	302	316	330	344	358	372	386

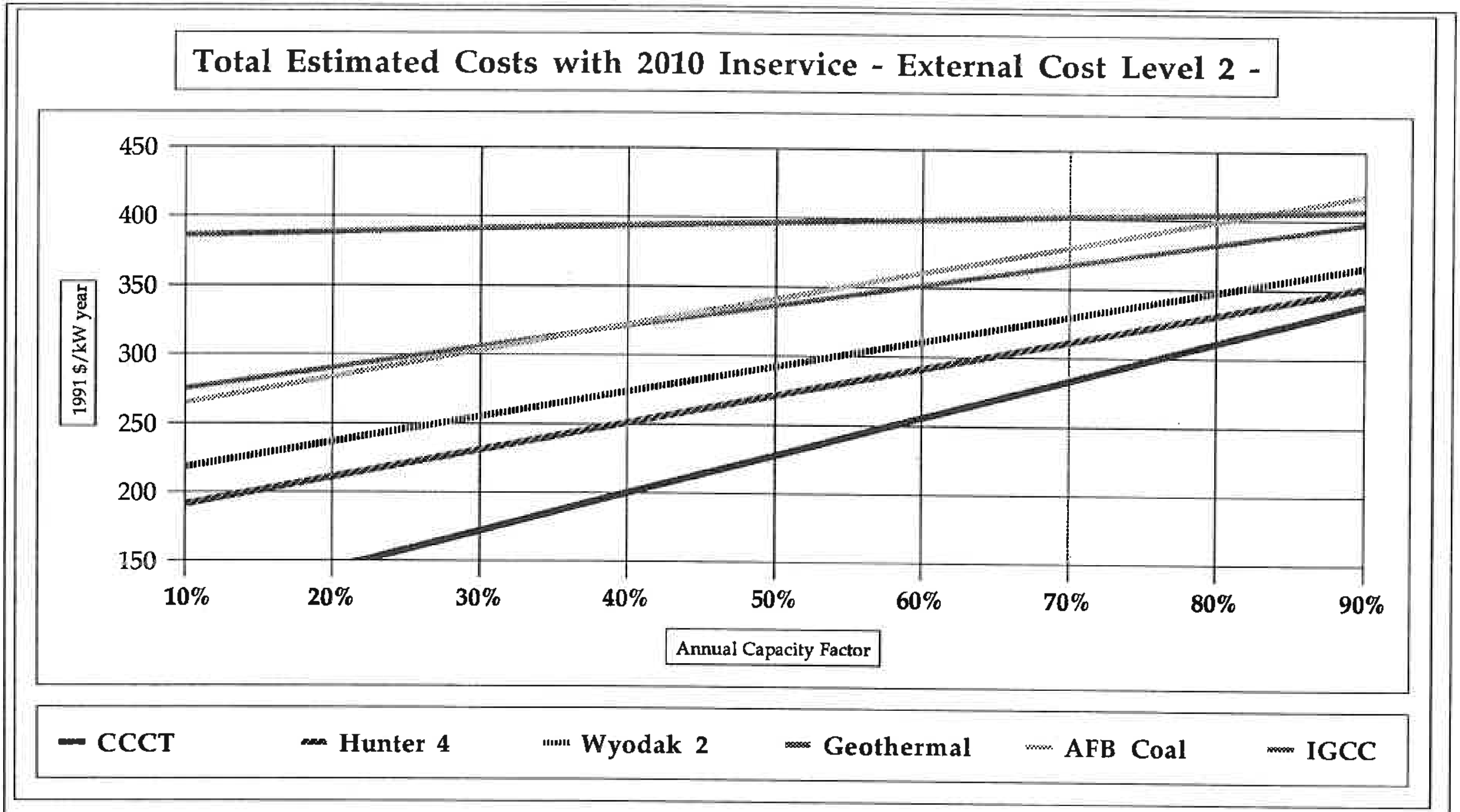
Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, No External Costs.



Total Estimated Costs with 2010 Inservice - External Cost Level 1 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	118	148	177	206	236	265	295	324	354
Hunter 4	187	203	218	234	250	266	282	298	314
Wyodak 2	214	228	242	256	271	285	299	313	328
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	266	287	308	329	350	371	392	412	433
IGCC	278	297	315	334	352	371	390	408	427

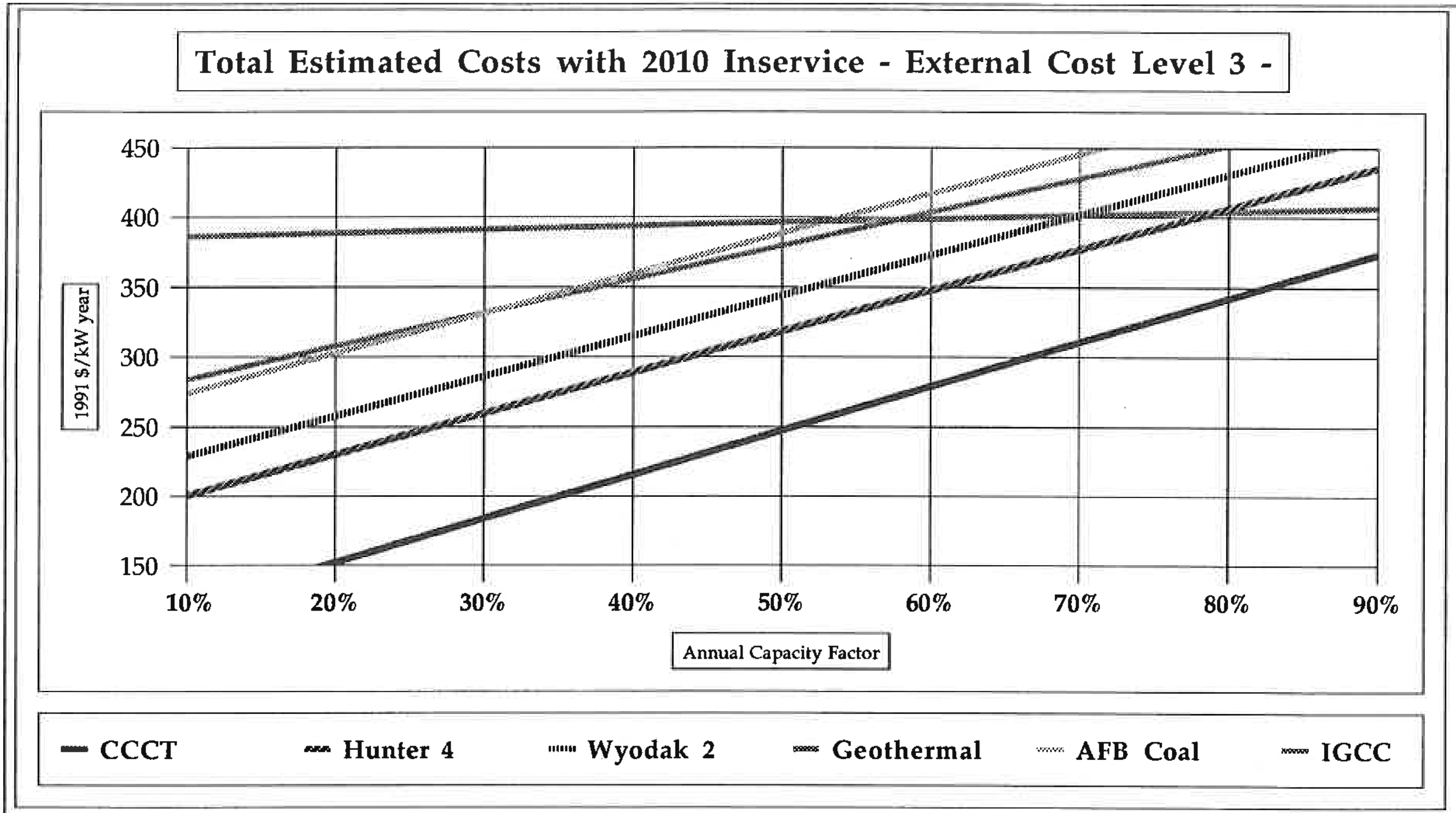
Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 1.



Total Estimated Costs with 2010 Inservice - External Cost Level 2 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	116	144	172	200	228	255	283	311	339
Hunter 4	191	211	231	251	271	291	311	331	351
Wyodak 2	218	236	255	273	292	311	329	348	366
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	264	283	303	322	341	360	380	399	418
IGCC	275	290	306	321	336	352	367	382	397

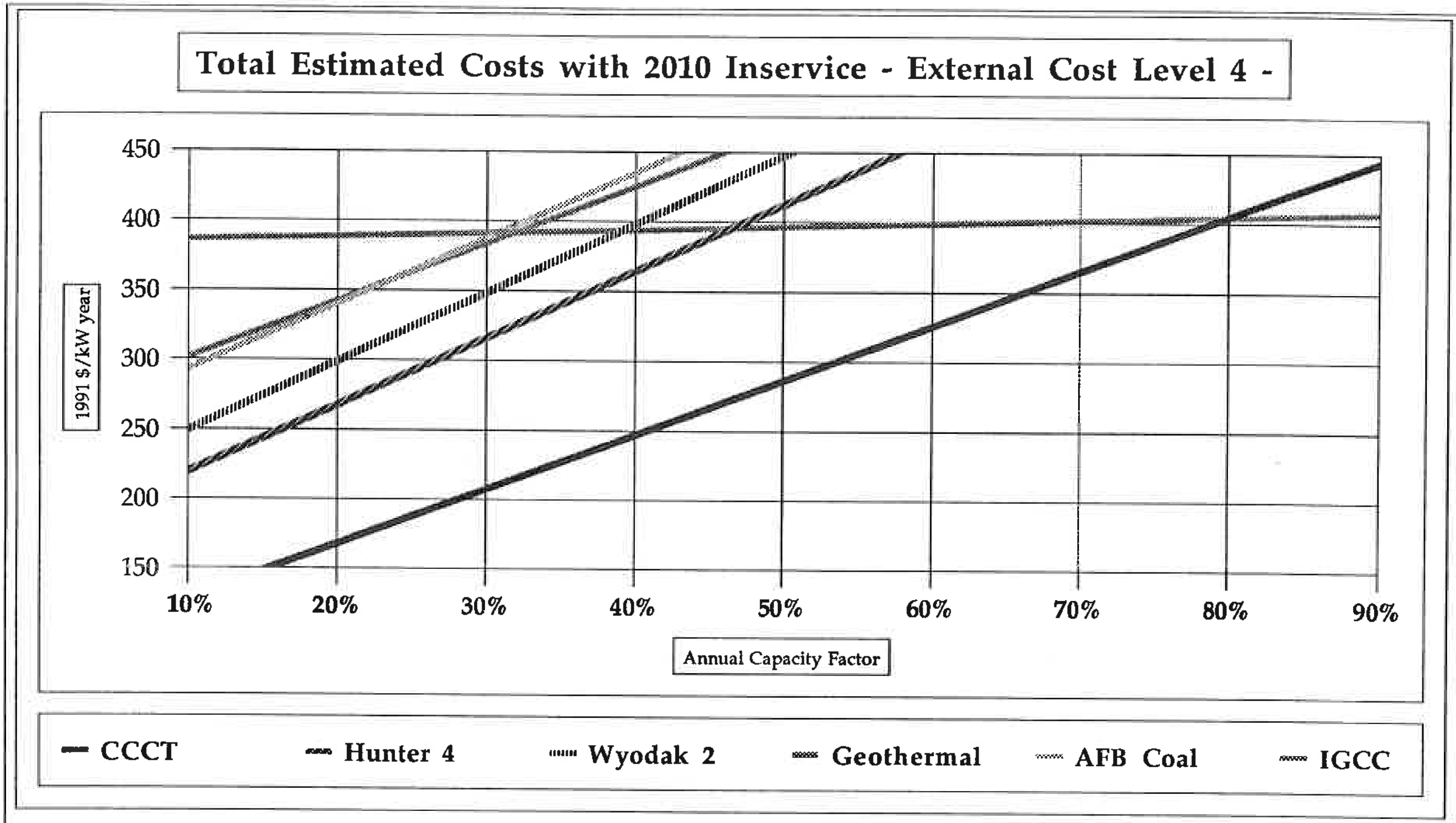
Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 2.



Total Estimated Costs with 2010 Inservice - External Cost Level 3 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	120	152	184	215	247	279	310	342	374
Hunter 4	200	230	259	289	318	348	377	406	436
Wyodak 2	228	257	286	315	344	373	402	430	459
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	274	302	331	360	388	417	445	474	503
IGCC	284	308	332	356	380	404	427	451	475

Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 3.

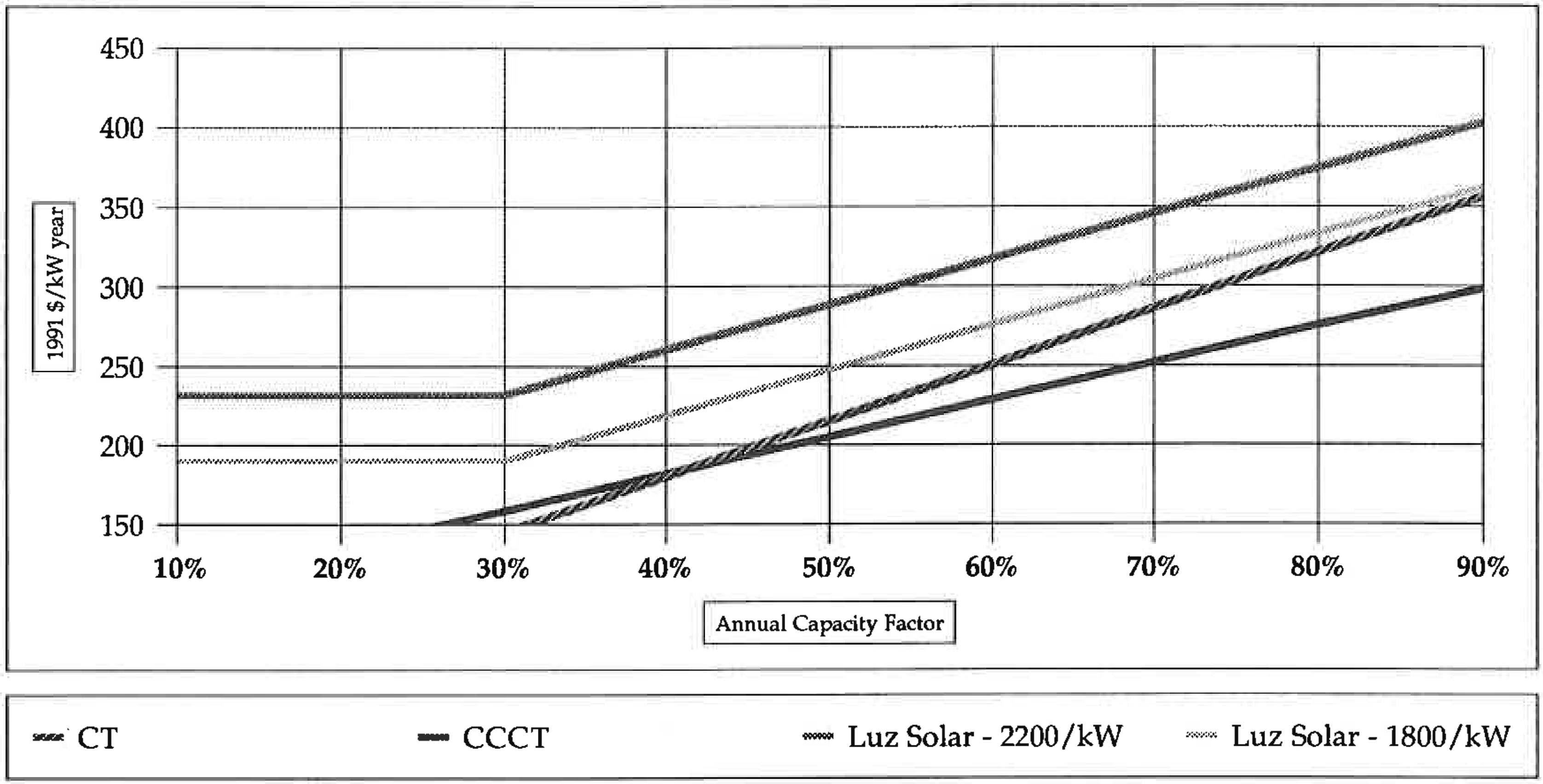


Total Estimated Costs with 2010 Inservice - External Cost Level 4 - in Total 1991 $/kW year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CCCT	128	168	207	247	286	325	365	404	444
Hunter 4	219	267	316	364	412	461	509	557	605
Wyodak 2	249	299	348	398	447	497	547	596	646
Geothermal	386	388	391	394	396	399	402	404	407
AFB Coal	293	340	387	435	482	530	577	625	672
IGCC	301	342	384	425	466	507	549	590	631

Note : Real Levelized 1991 $'s/kW year. Base Gas Assumptions, External Cost Level 4.

Total Estimated Costs with 1996 Inservice - No External Cost -

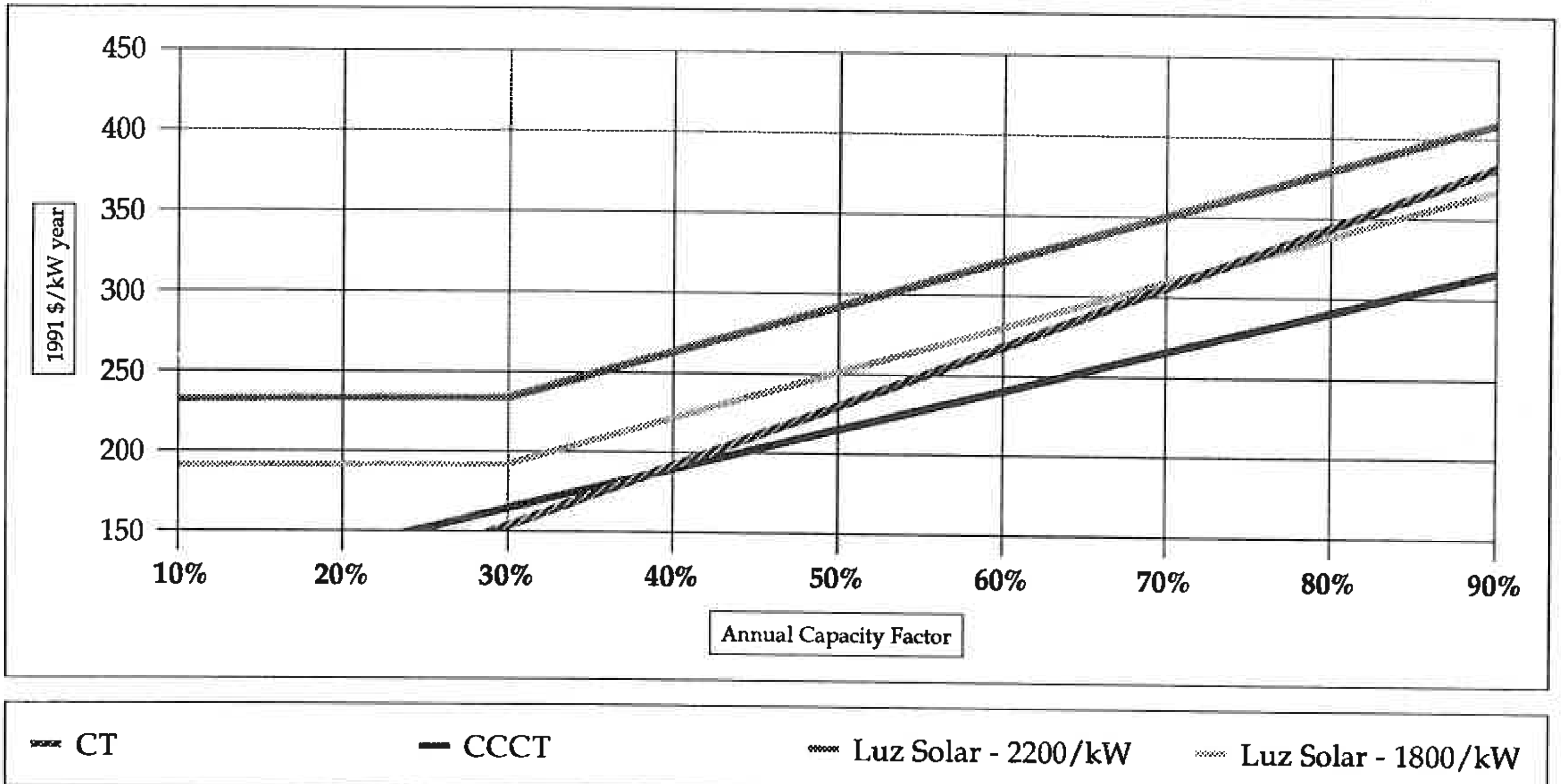


Total Estimated Costs with 1996 Inservice - No External Cost - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	74	110	145	180	215	250	286	321	356
CCCT	112	135	159	182	205	228	252	275	298
Luz Solar - 2200/kW	231	231	231	260	288	317	345	374	403
Luz Solar - 1800/kW	190	190	190	219	247	276	304	333	361

Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, No External Costs.

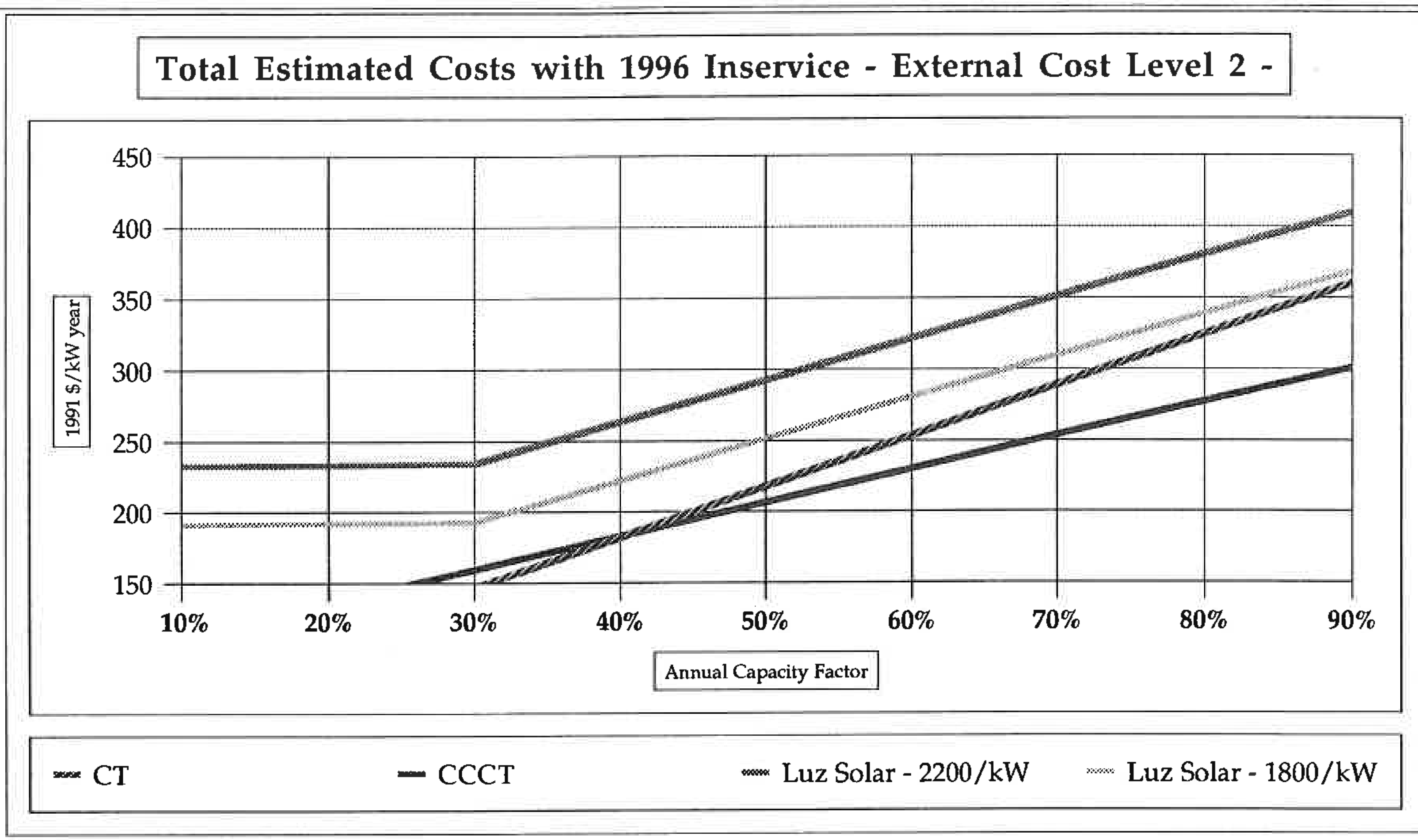
Total Estimated Costs with 1996 Inservice - External Cost Level 1 -



Total Estimated Costs with 1996 Inservice - External Cost Level 1 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	77	115	153	191	229	267	306	344	382
CCCT	114	139	164	190	215	240	266	291	316
Luz Solar - 2200/kW	232	233	233	263	292	321	350	379	408
Luz Solar - 1800/kW	191	192	192	221	251	280	309	338	367

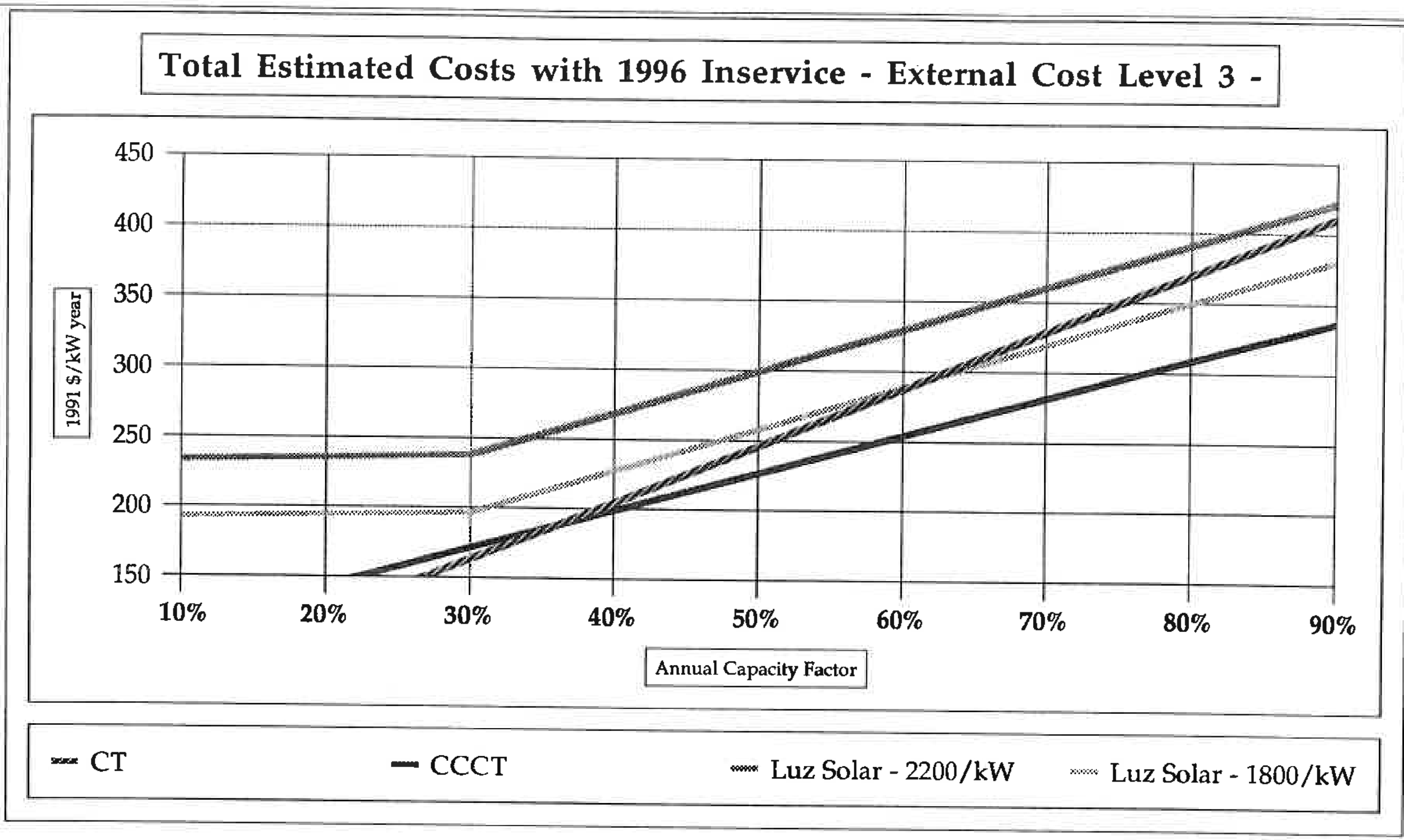
Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 1.



Total Estimated Costs with 1996 Inservice - External Cost Level 2 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	75	110	146	182	217	253	289	324	360
CCCT	112	136	159	183	207	230	254	277	301
Luz Solar - 2200/kW	232	233	234	263	292	322	351	380	409
Luz Solar - 1800/kW	191	192	193	222	251	280	310	339	368

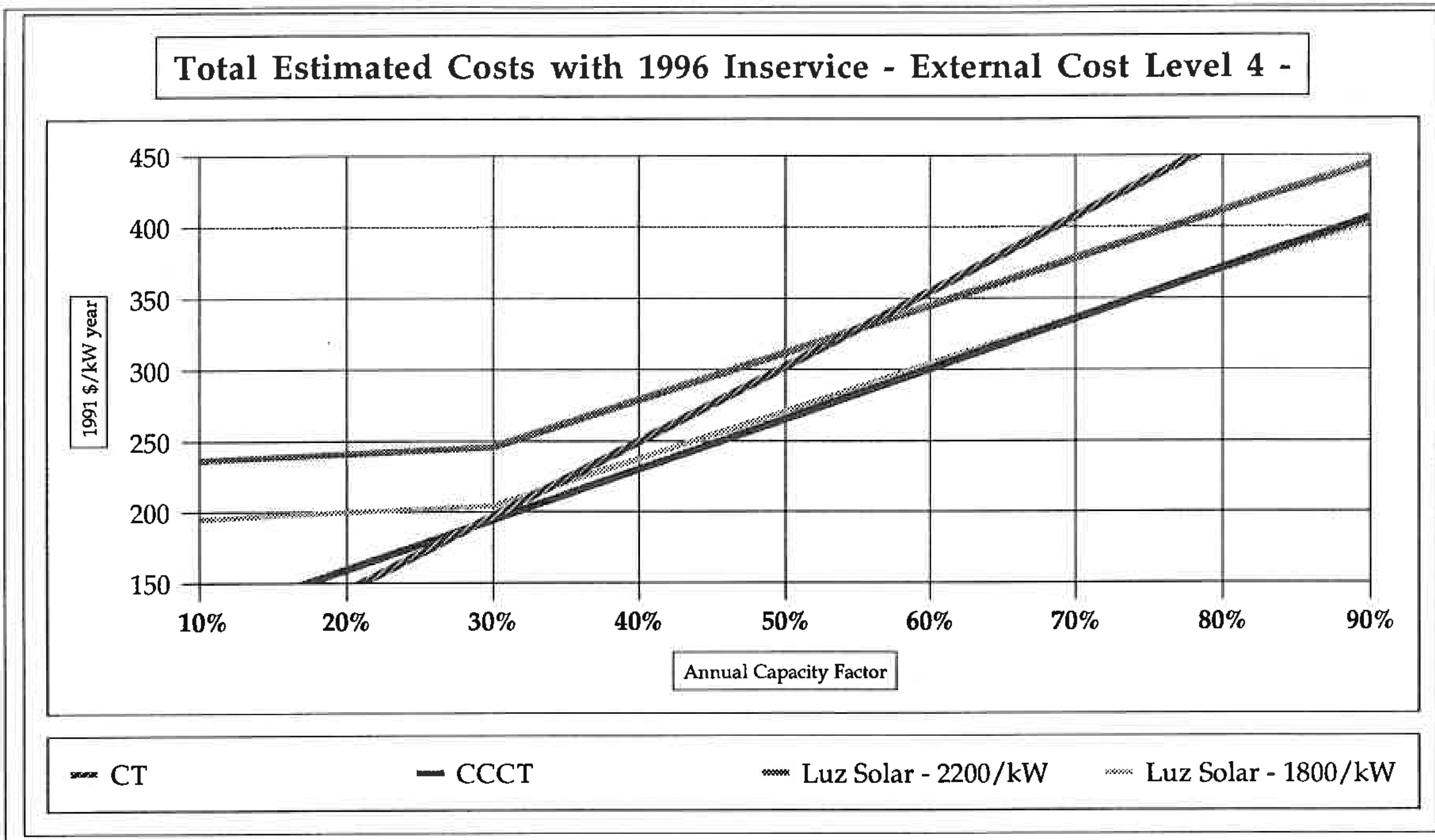
Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 2.



Total Estimated Costs with 1996 Inservice - External Cost Level 3 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	80	122	163	204	246	287	328	369	411
CCCT	116	144	171	199	226	254	281	309	336
Luz Solar - 2200/kW	234	236	238	268	299	329	360	390	421
Luz Solar - 1800/kW	192	194	196	227	258	288	319	349	380

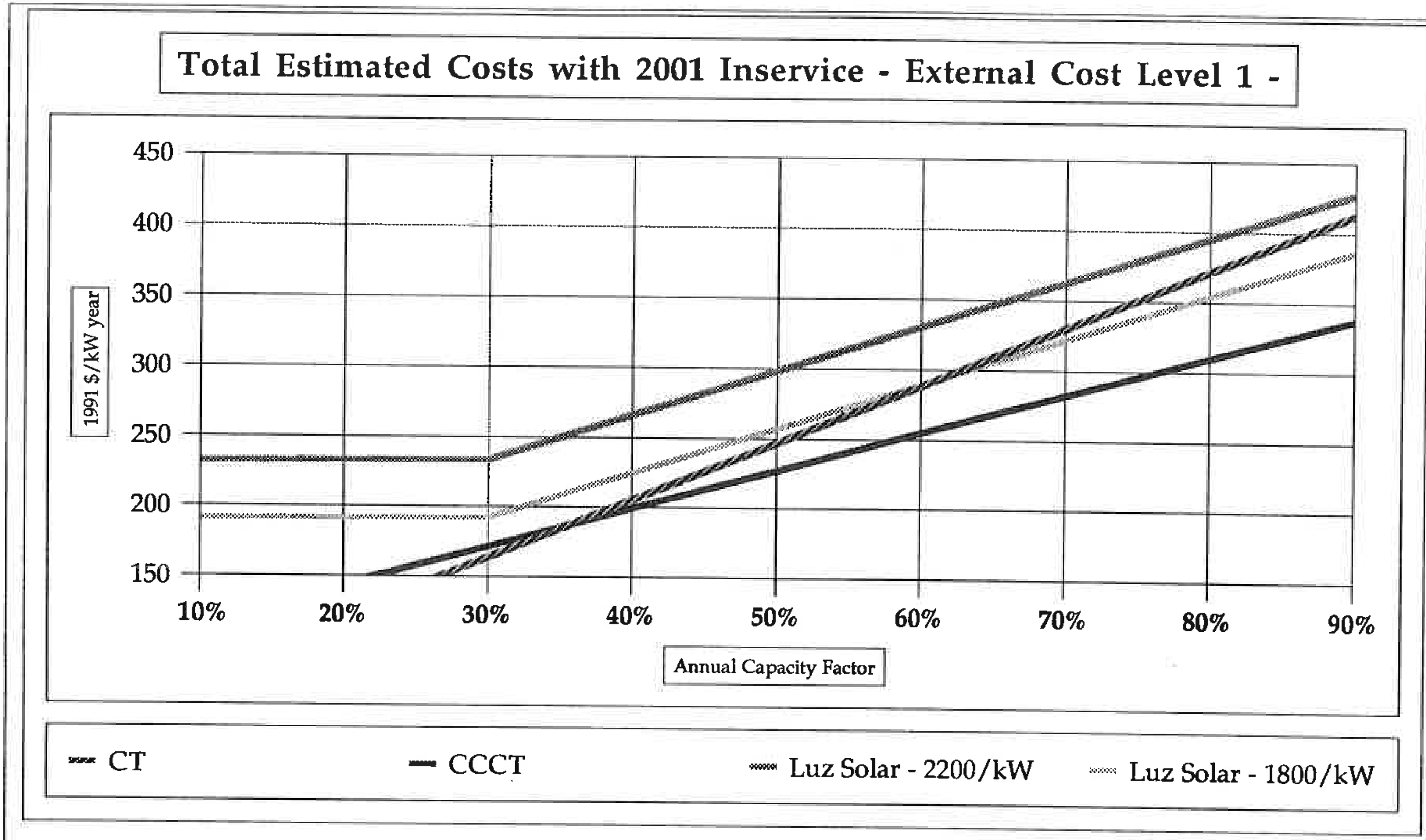
Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 3.



Total Estimated Costs with 1996 Inservice - External Cost Level 4 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	92	144	197	249	302	354	407	460	512
CCCT	124	159	195	230	265	300	336	371	406
Luz Solar - 2200/kW	236	241	245	278	312	345	378	411	444
Luz Solar - 1800/kW	195	199	204	237	270	303	337	370	403

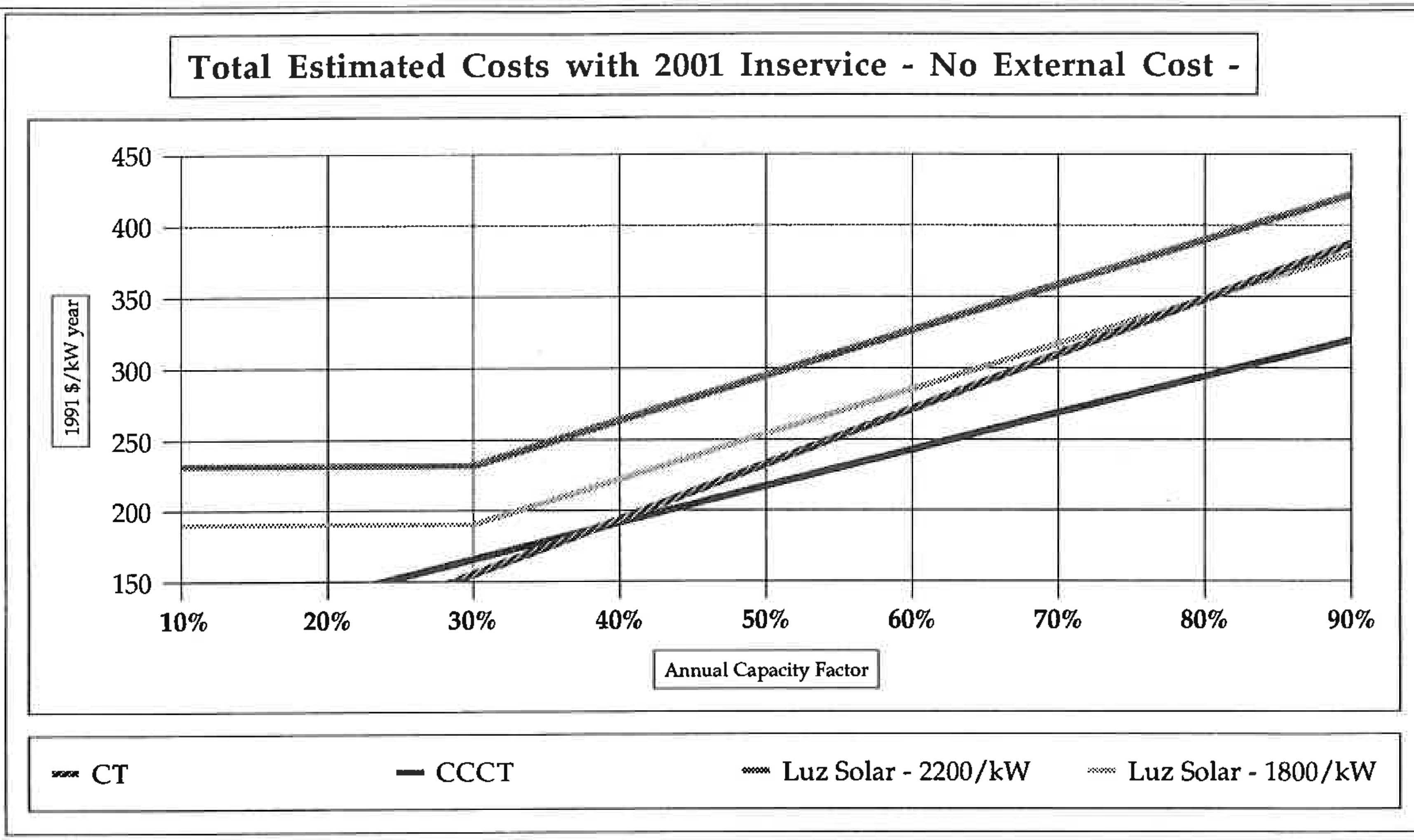
Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 4.



Total Estimated Costs with 2001 Inservice - External Cost Level 1 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	81	122	164	205	247	288	329	371	412
CCCT	116	144	172	199	227	254	282	310	337
Luz Solar - 2200/kW	232	233	233	266	298	330	363	395	427
Luz Solar - 1800/kW	191	192	192	224	257	289	321	354	386

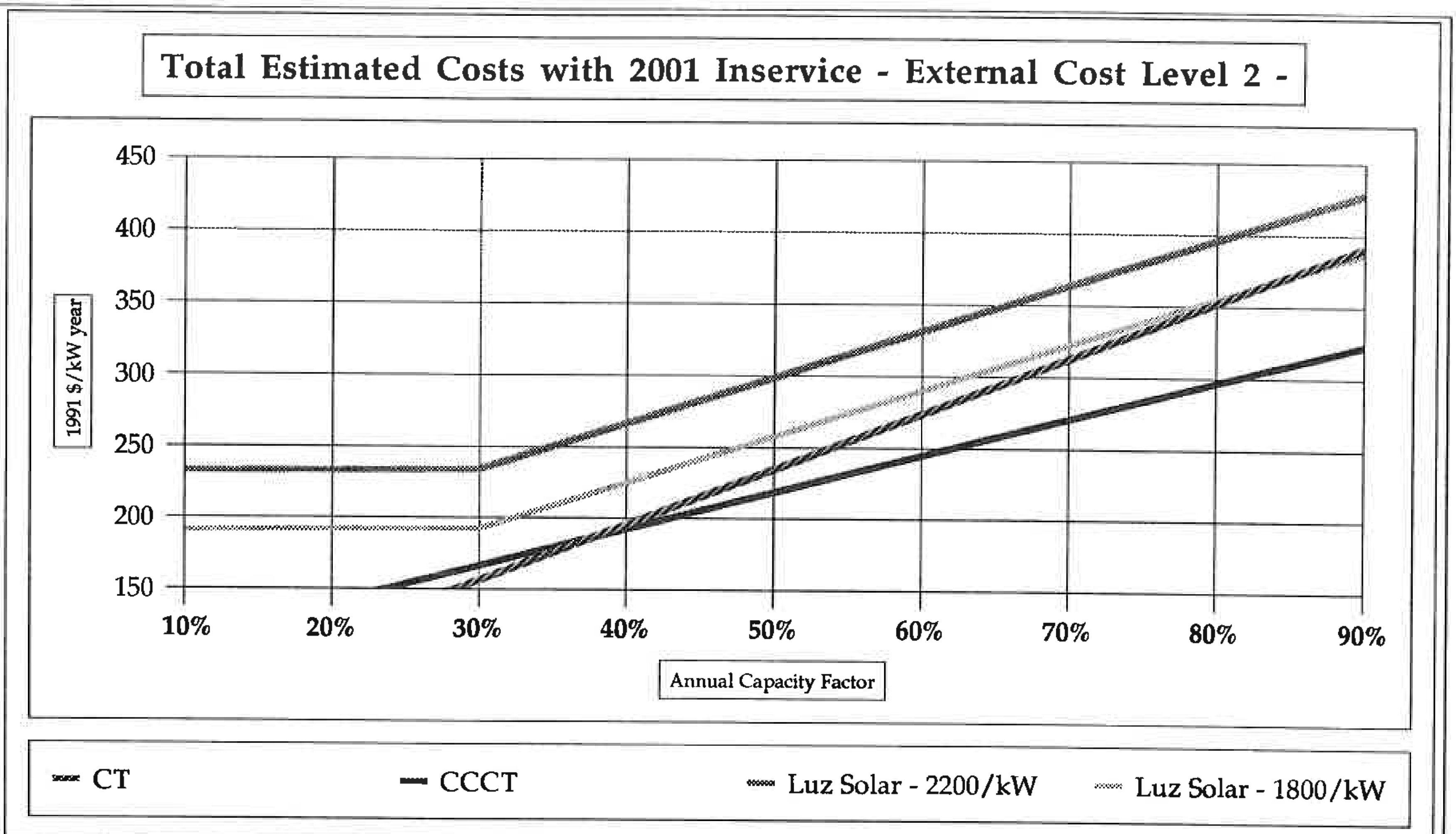
Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 1.



Total Estimated Costs with 2001 Inservice - No External Cost - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	78	116	155	194	232	271	310	348	387
CCCT	114	140	166	191	217	243	268	294	320
Luz Solar - 2200/kW	231	231	231	263	295	326	358	390	421
Luz Solar - 1800/kW	190	190	190	222	253	285	317	348	380

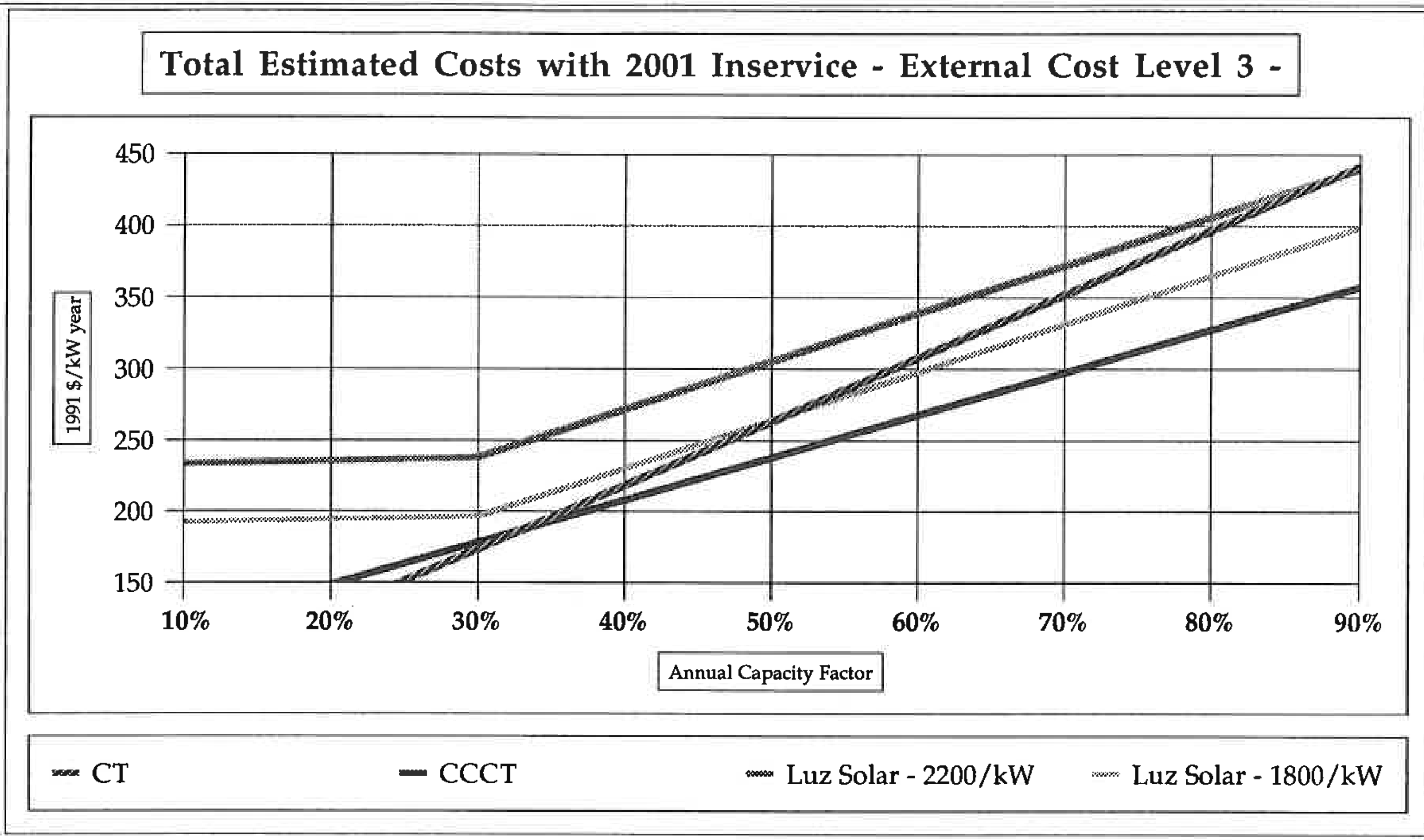
Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, No External Costs.



Total Estimated Costs with 2001 Inservice - External Cost Level 2 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	78	117	156	195	234	274	313	352	391
CCCT	115	141	167	193	218	244	270	296	322
Luz Solar - 2200/kW	232	233	234	266	299	331	363	396	428
Luz Solar - 1800/kW	191	192	193	225	257	290	322	354	387

Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 2.

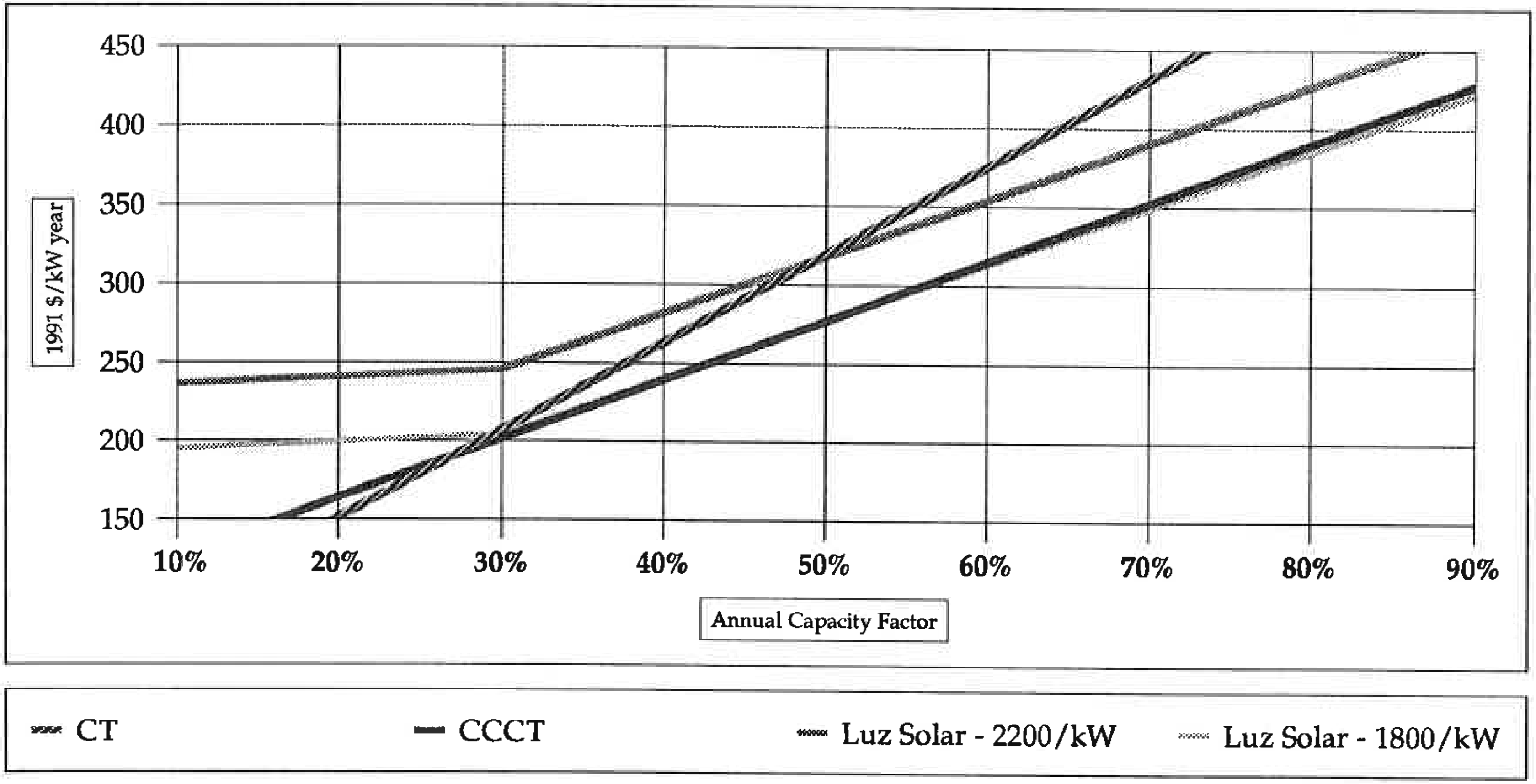


Total Estimated Costs with 2001 Inservice - External Cost Level 3 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	84	129	173	218	263	307	352	397	441
CCCT	118	148	178	208	238	268	298	327	357
Luz Solar - 2200/kW	234	236	238	271	305	339	372	406	440
Luz Solar - 1800/kW	192	194	196	230	264	297	331	365	398

Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 3.

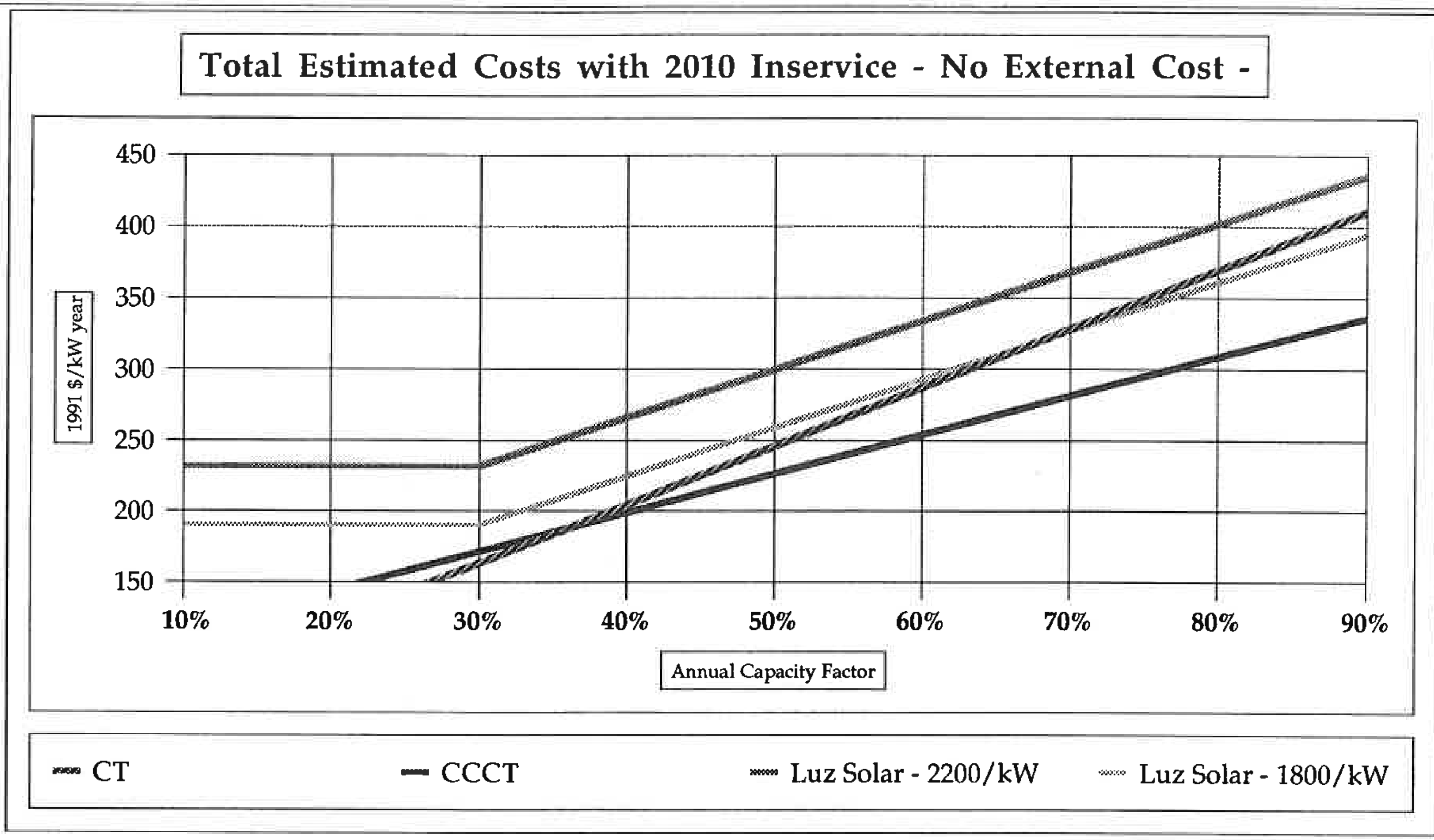
Total Estimated Costs with 2001 Inservice - External Cost Level 4 -



Total Estimated Costs with 2001 Inservice - External Cost Level 4 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	95	151	207	263	319	375	431	487	543
CCCT	126	164	202	239	277	315	352	390	428
Luz Solar - 2200/kW	236	241	245	282	318	354	390	426	463
Luz Solar - 1800/kW	195	199	204	240	277	313	349	385	421

Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 4.

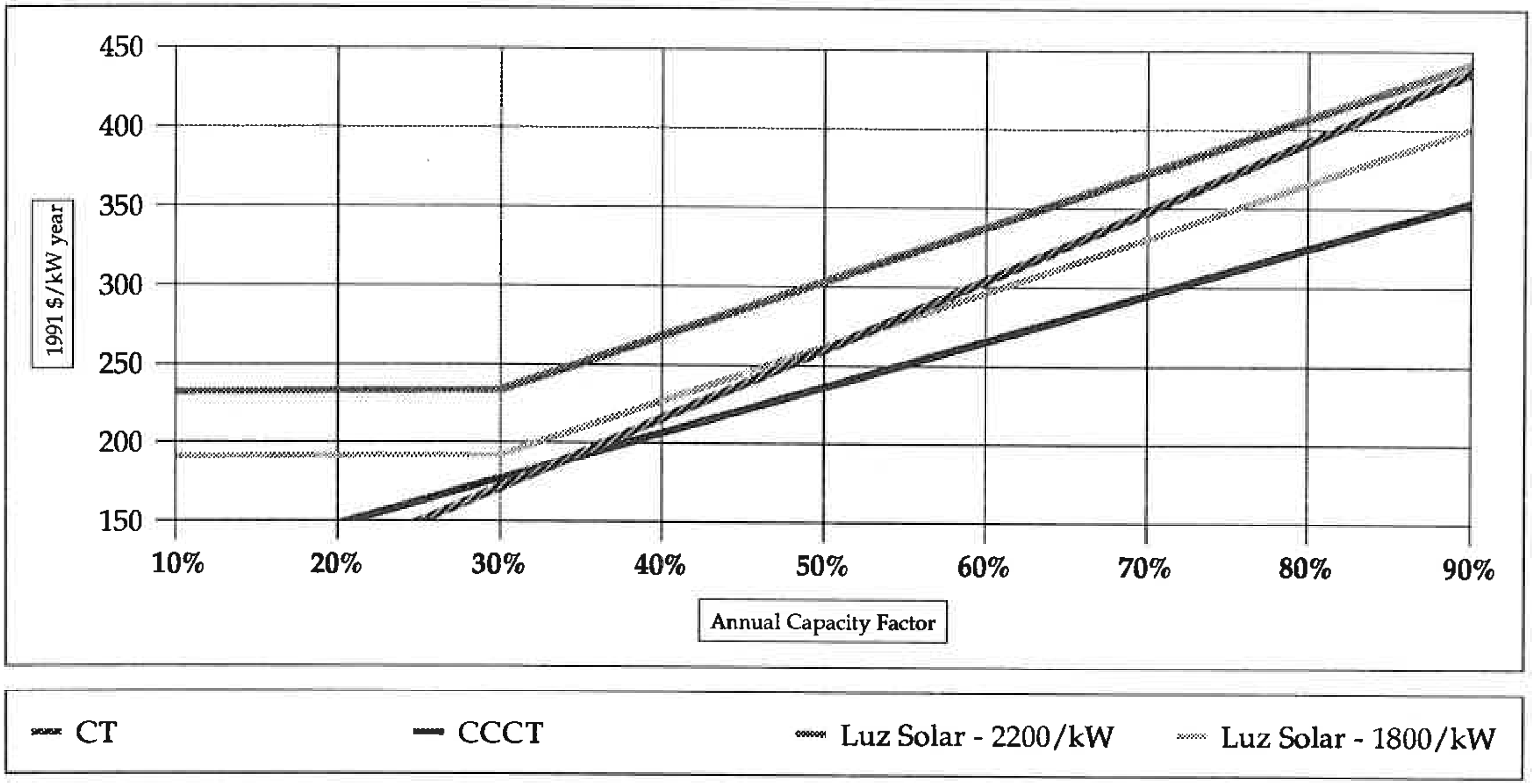


Total Estimated Costs with 2010 Inservice - No External Cost - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	80	122	163	204	245	287	328	369	411
CCCT	116	144	171	199	226	254	281	309	336
Luz Solar - 2200/kW	231	231	231	265	299	333	367	401	435
Luz Solar - 1800/kW	190	190	190	224	258	292	326	360	394

Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, No External Costs.

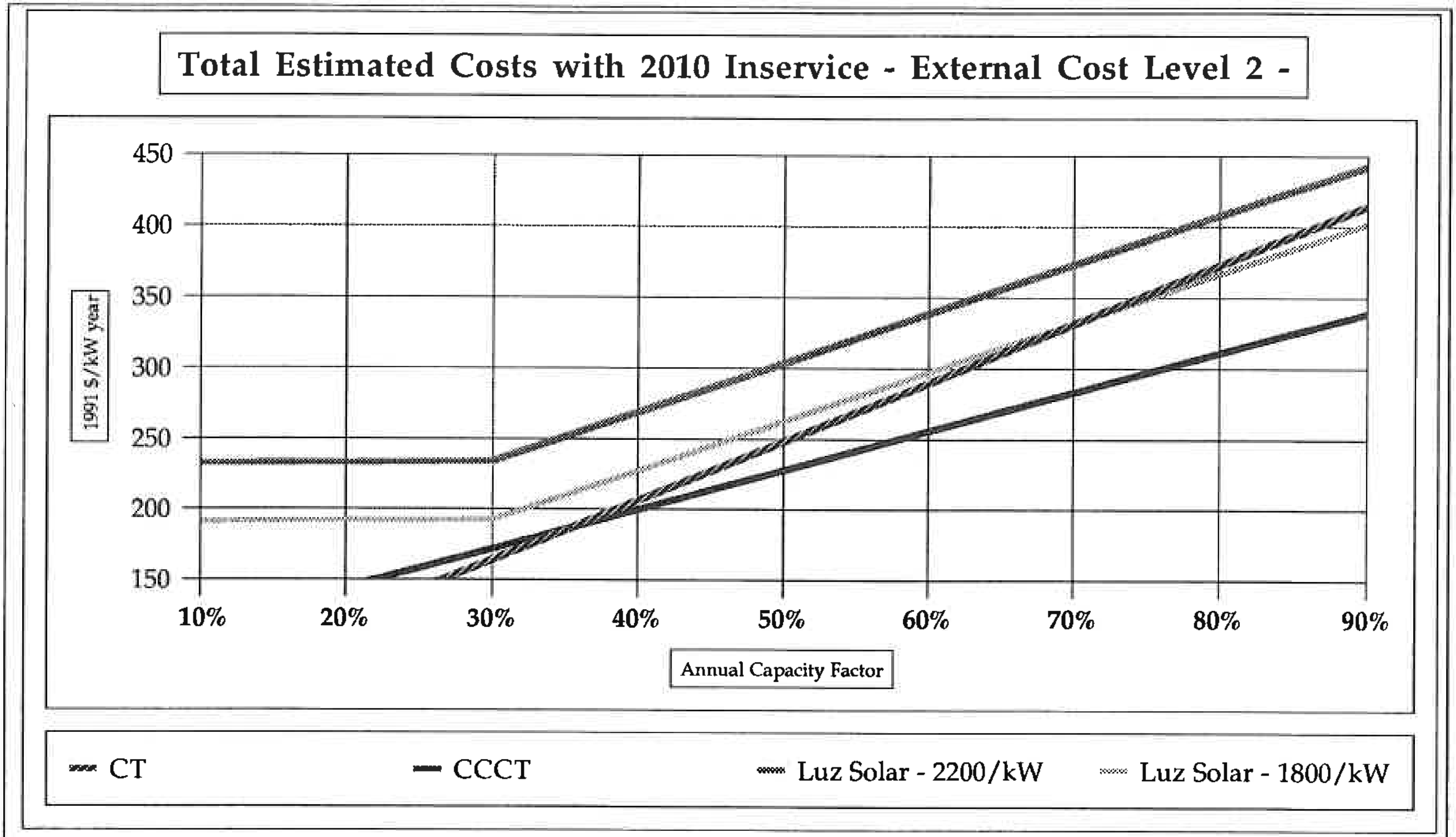
Total Estimated Costs with 2010 Inservice - External Cost Level 1 -



Total Estimated Costs with 2010 Inservice - External Cost Level 1 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	83	127	171	216	260	304	348	392	436
CCCT	118	148	177	206	236	265	295	324	354
Luz Solar - 2200/kW	232	233	233	268	303	337	372	407	441
Luz Solar - 1800/kW	191	192	192	227	262	296	331	366	400

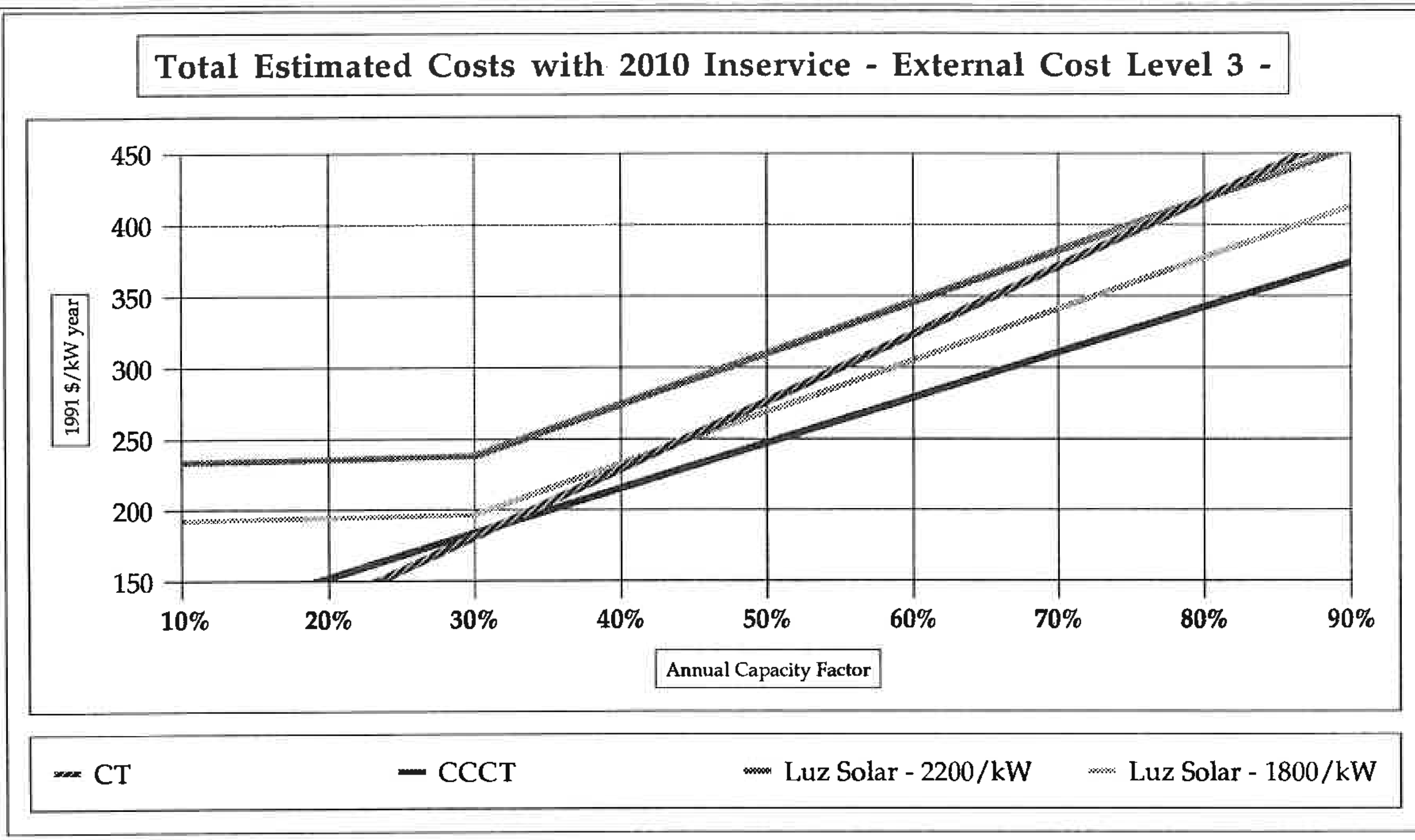
Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 1.



Total Estimated Costs with 2010 Inservice - External Cost Level 2 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	81	123	164	206	248	289	331	373	414
CCCT	116	144	172	200	228	255	283	311	339
Luz Solar - 2200/kW	232	233	234	269	303	338	373	408	442
Luz Solar - 1800/kW	191	192	193	227	262	297	332	366	401

Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 2.

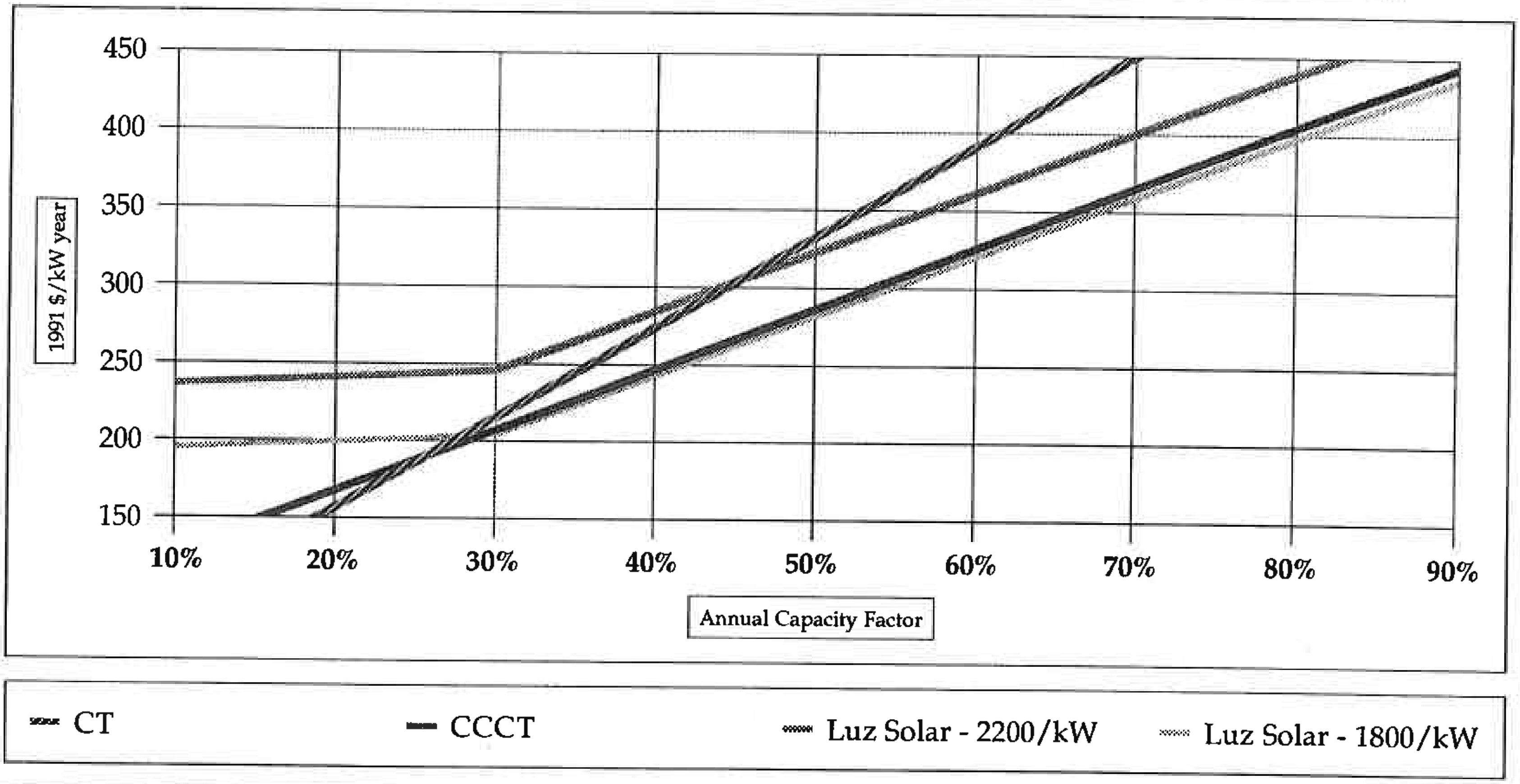


Total Estimated Costs with 2010 Inservice - External Cost Level 3 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	86	134	181	228	276	323	370	418	465
CCCT	120	152	184	215	247	279	310	342	374
Luz Solar - 2200/kW	234	236	238	274	310	346	382	418	454
Luz Solar - 1800/kW	192	194	196	232	269	305	341	377	413

Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 3.

Total Estimated Costs with 2010 Inservice - External Cost Level 4 -



Total Estimated Costs with 2010 Inservice - External Cost Level 4 - in Total 1991 $/kW Year

	Annual Capacity Factor								
	10%	20%	30%	40%	50%	60%	70%	80%	90%
CT	98	156	215	274	332	391	449	508	567
CCCT	128	168	207	247	286	325	365	404	444
Luz Solar - 2200/kW	236	241	245	284	323	361	400	438	477
Luz Solar - 1800/kW	195	199	204	243	281	320	359	397	436

Note : Real Levelized 1991 $'s/kW yr, Base Gas Assumptions, External Cost Level 4.

BALANCED PLANNING FOR GROWTH

Technical Appendix: Load Forecasts

Resource and Market Planning Program
RAMPP - 2

May 14, 1992

PACIFICORP

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LOAD FORECASTING - METHODOLOGY

INTRODUCTION

The development of a long range electricity sales forecast is one first step towards developing a least cost plan. The sales forecast estimates how much electricity retail customers (this includes interruptible and regular sales for resale customers) will require in the next twenty years. Utilities must evaluate their business over a twenty year planning horizon in order to make efficient least cost resource decisions involving supply and demand side options that can, in many instances, take many years to construct or develop. This chapter describes the methodology used in developing electricity sales forecasts and supporting economic and demographic forecasts.

Economic and demographic assumptions are major factors influencing the forecasts of electricity sales. Absent other changes, demand for electricity will parallel other regional economic activities. However as we have seen historically, this relationship will be modified by changes in the price of electricity, the price and availability of competing fuels, changes in the composition of economic activity, the level of conservation activity, and the rate at which buildings and energy using appliances are replaced.

The forecasting process can be thought of as a model that relates information "inputs" and produces "outputs". A range of values for certain variables are input into the forecasting model to produce a range of forecasts.

Recognizing that the future is highly uncertain, four separate forecasts have been developed to bound this uncertainty. These four separate forecasts are referred to as: low, medium-low, medium-high, and high. The high and the low forecasts are designed to bound the forecast in such a way that the likelihood of the future unfolding outside the range is highly unlikely. (In this context, "highly unlikely" refers to a 90% confidence level - i.e. there is a one in ten chance that future long-term economic growth will lie outside the bounds of the high and low forecasts.) 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 Company has utilized three of Data Resource's (DRI) long term forecasts of the US economy - the Optimistic, Trend, & Pessimistic forecasts - in developing the four forecasts described above. The Company believes that DRI's forecasts encompass a wide range of National forecasts which allow resource decisions to be adequately tested. Further enhancements are made by combining these national ranges with regional ranges. The medium high and medium low forecasts combine the National

Trend forecast with regional economic forecasts, in which, compared to historic patterns, the regional economy grows faster (slower) than historically. The High (Low) forecasts differ from the Medium High (Medium Low) forecasts by replacing the Trend forecast with the Optimistic (Pessimistic) forecasts. The inputs which generate the forecasts are not from one particular historical period, but reflect a consistent set of inputs which could occur in the future. No point forecast can ever be exactly correct in projecting the future and it is important not to dwell on whether the forecast is perfect. Rather it is the range of forecasts that are more important and the belief that they will encompass a wide enough range of uncertainty to test the Company's resource strategies.

The forecast range technique is similar to the one developed and used by the Pacific Northwest Power Planning Council. Like the Regional Council, the Company believes that, in the long term, the most probable range of forecasts is bounded by the medium-low and medium-high forecasts.

The forecast at sales level prepared by Pacificorp Electric Operations (PEO) as part of the Least Cost Planning Process is an annual forecast for each of the residential, commercial, industrial, irrigation, and "other" customer classes. The forecast is derived from a consistent set of economic, demographic, and price projections specific to each of the nine zones, in seven states, served by the Company. These states are California, Idaho, Montana, Oregon, Utah, Washington, and Wyoming. Both Idaho and Wyoming are served by both the Pacific & Utah Divisions of the Company. Forecasts of economic and demographic variables, such as employment, population, and income are produced for each of the nine zones and the results are used as inputs into the electricity sales forecasting models. The system wide forecast for each level (high, medium-high, medium-low and low) is the sum of the nine zonal forecasts. For example, the "high" electricity sales forecast of Pacificorp equals the sum of the "high" forecasts for all nine zones.

Two basic forecasting methods are used to predict sales: a combined econometric/end-use analysis of the residential and commercial models, and an econometric forecast of the remaining customers groups. After the annual sales forecast has been completed, a monthly system input energy and peak forecast is prepared for each of the nine zones, the Pacific & Utah Divisions, and the Total Company. An annual system input forecast is developed by adding estimates of system losses (the amount of electricity lost between the point of generation and the customer) to the sales forecasts results. The annual energy is broken into monthly data on the basis of historic seasonal patterns. Historic load factors are used in developing monthly peak forecasts. These monthly load factors are developed for each zone using merged company data. As new resources (both supply and demand side) are added, these load factors will change and these changes are reflected in the sales to customers after resource decisions are made.

The document contains the following chapters. First, a brief discussion of the employment and sales forecasts for each of the four scenarios. That tables that give average growth rates for employment and sales for the four scenarios at both the sector and state levels. The next major section - **Economics and Demographics** - has three subsections which describes the methodology used to generate the Employment, Population, and Employment forecasts. The final major section - **Energy** - has six subsections, an introduction, and chapters describing the methodology used to produce the Residential, Commercial, Industrial, and Other Sales forecasts, and the Monthly System Peak and Energy Forecasts. The main part of the text concludes with sections on **Public Process, Statistical Philosophy** and **Anticipated Changes and Enhancements.** Following the main text are sections showing **Detailed Annual Sales Forecasts by Customer Class & Zone** and **Monthly Peak & Energy Forecasts by Zone.**

EMPLOYMENT AND SALES FORECASTS

The employment forecasts show a wide range of results. In the medium high case, total employment is expected to grow at an average rate of 2.1% per year between 1990 and 2012. At this rate of growth, 1.1 million employees (51,000 per year) are added to total employment. The majority of these new employees are added to the non-basic employment category, indicating a continuing trend toward commercial and service-related employment.

In the medium low case, over 734,000 new employees are added to total employment by 2012 as employment averages growth of 1.4% over the forecast period. All of the new growth is in the non-basic employment category, with three of the four basic employment categories declining over the forecast interval. This trend is even more obvious in the low forecast, in which, even though total employment grows by over 342,000 employees, all four of the basic sectors decline over the twenty two years of the forecast.

The sales forecast methodology resulted in four energy forecasts with 20 year growth rates for energy of 0.5 percent in the low case, 1.7 percent in the medium-low case, 3.1 percent in the medium-high case, and 4.0 percent in the high case. The growth rates for the summer and winter peaks are very similar. The growth is forecast to be slightly higher in the early years, than the later years, and to be slightly higher for the

Utah Division than for the Pacific Division. In absolute terms, the amount of energy added during the forecast period varies from 373 MWa in the low case (almost zero growth) to 5,929 MWa in the high case (more than doubling the 1990 level). The fastest growing component of retail sales varies between scenarios. In the low & medium low scenarios, sales to residential customers grow the fastest. In the medium high forecast, industrial sales grow the fastest, and in the high scenario, the commercial sector is the fastest growing component of retail sales.

To reiterate, these four forecasts demonstrate the magnitude of uncertainty that is faced with regard to future retail sales. On the one hand, under the low case total retail sales could be 5 percent higher (2 million Mwh) than they are today by the year 2012. On the other hand, under the high case total retail sales could more than double (+ 126 percent) from the level they are today by the year 2012.

The first set of tables following give the Annual Average Rates of Growth for electricity sales and employment by major sector for each of the four scenarios at the total company level. The second set of tables list the Annual Average Rates of Growth for electricity sales for the nine zones for each of the four scenarios.

Pacificorp - Rampp 2 - High Sales Forecast

Average Annual Rates of Growth (%)

Sales by Sector

	Residential	Commercial	Industrial	Other	Total
1991 - 1996	3.6	4.9	5.0	2.4	4.5
1996 - 2001	3.7	4.5	4.6	2.3	4.2
2001 - 2006	3.5	3.8	3.8	2.0	3.7
2006 - 2011	3.6	3.2	2.6	1.6	3.0
1991 - 2001	3.7	4.7	4.8	2.4	4.4
2001 - 2011	3.6	3.5	3.2	1.8	3.3
1991 - 2011	4.1	4.0	4.0	2.1	3.9

Average Annual Rates of Growth (%)

Employment by Major Sector

	Manufacturing	Mining	Agriculture	Federal Government	Basic	Non-Basic	Total
1991 - 1996	2.6	2.8	0.9	(0.5)	1.6	3.1	2.8
1996 - 2001	1.6	3.5	0.8	0.7	1.5	3.0	2.7
2001 - 2006	0.7	3.8	0.5	1.3	1.1	2.6	2.4
2006 - 2011	0.4	3.9	0.4	0.9	0.9	2.3	2.1
1991 - 2001	2.1	3.1	0.8	0.1	1.5	3.0	2.7
2001 - 2011	0.6	3.8	0.5	1.1	1.0	2.5	2.2
1991 - 2011	1.3	3.5	0.6	0.6	1.3	2.7	2.5

Pacificorp - Rampp 2 - Medium High Sales Forecast

Average Annual Rates of Growth (%)

Sales by Sector

	Residential	Commercial	Industrial	Other	Total
1991 - 1996	2.5	3.2	3.9	1.9	3.3
1996 - 2001	2.7	3.3	3.6	1.9	3.2
2001 - 2006	2.7	3.0	3.1	1.6	2.9
2006 - 2011	3.0	2.6	2.0	1.3	2.4
1991 - 2001	2.6	3.3	3.8	1.9	3.3
2001 - 2011	2.8	2.8	2.5	1.5	2.6
1991 - 2011	2.7	3.0	3.2	1.7	2.9

Average Annual Rates of Growth (%)

Employment by Major Sector

	Manufacturing	Mining	Agriculture	Federal Government	Basic	Non-Basic	Total
1991 - 1996	2.1	2.2	0.6	(0.9)	1.2	2.7	2.4
1996 - 2001	1.2	3.0	0.5	0.4	1.1	2.6	2.3
2001 - 2006	0.4	3.5	0.3	0.9	0.8	2.3	2.0
2006 - 2011	0.1	3.8	0.2	0.6	0.6	2.0	1.8
1991 - 2001	1.7	2.6	0.5	(0.3)	1.1	2.6	2.3
2001 - 2011	0.2	3.6	0.2	0.8	0.7	2.2	1.9
1991 - 2011	0.9	3.1	0.4	0.2	0.9	2.4	2.1

Pacificorp - Rampp 2 - Medium Low Sales Forecast

Average Annual Rates of Growth (%)

Sales by Sector

	Residential	Commercial	Industrial	Other	Total
1991 - 1996	1.4	1.6	2.4	1.1	1.9
1996 - 2001	1.1	1.4	1.2	0.8	1.5
2001 - 2006	1.7	1.5	1.7	0.8	1.5
2006 - 2011	2.4	1.5	0.9	0.8	1.4
1991 - 2001	1.3	1.5	1.8	0.9	1.5
2001 - 2011	2.0	1.5	1.1	0.8	1.5
1991 - 2011	1.6	1.5	1.5	0.9	1.5

Average Annual Rates of Growth (%)

Employment by Major Sector

	Manufacturing	Mining	Agriculture	Federal Government	Basic	Non-Basic	Total
1991 - 1996	1.1	0.6	0.1	(1.1)	0.4	2.1	1.8
1996 - 2001	(0.2)	0.4	(0.2)	0.1	(0.1)	1.7	1.4
2001 - 2006	(0.2)	0.2	(0.5)	0.6	0.0	1.7	1.4
2006 - 2011	(0.2)	(0.1)	0.1	0.3	0.0	1.7	1.4
1991 - 2001	0.5	0.5	0.0	(0.5)	0.2	1.9	1.6
2001 - 2011	(0.2)	0.0	(0.2)	0.5	0.0	1.7	1.4
1991 - 2011	0.2	0.2	(0.1)	0.0	0.1	1.8	1.5

Pacificorp - Rampp 2 - Low Sales Forecast

Average Annual Rates of Growth (%)

Sales by Sector

	Residential	Commercial	Industrial	Other	Total
1991 - 1996	0.1	0.0	1.0	0.5	0.5
1996 - 2001	0.0	(0.2)	0.5	0.1	0.2
2001 - 2006	0.6	(0.1)	0.4	0.2	0.3
2006 - 2011	1.4	(0.1)	(0.1)	0.2	0.3
1991 - 2001	0.0	(0.1)	0.8	0.4	0.3
2001 - 2011	1.0	(0.1)	0.1	0.2	0.3
1991 - 2011	0.5	(0.1)	0.4	0.3	0.3

Average Annual Rates of Growth (%)

Employment by Major Sector

	Manufacturing	Mining	Agriculture	Federal Government	Basic	Non-Basic	Total
1991 - 1996	(0.1)	(0.8)	(0.3)	(1.4)	(0.5)	1.4	1.0
1996 - 2001	(1.5)	(1.1)	(0.6)	(0.2)	(1.0)	1.0	0.7
2001 - 2006	(1.5)	(1.4)	(0.9)	0.4	(1.0)	1.0	0.7
2006 - 2011	(1.5)	(1.8)	(0.3)	0.0	(0.9)	1.0	0.8
1991 - 2001	(0.8)	(0.9)	(0.5)	(0.8)	(0.7)	1.2	0.9
2001 - 2011	(1.5)	(1.6)	(0.6)	0.1	(0.9)	1.0	0.7
1991 - 2011	(1.2)	(1.3)	(0.5)	(0.3)	(0.8)	1.1	0.8

Pacificorp - Rampp 2 - Sales Forecast

Average Annual Rates of Growth (%)

Oregon Sales

	High	Medium High	Medium Low	Low
1991 - 1996	3.7	2.5	1.3	0.0
1996 - 2001	3.9	2.7	0.6	(0.3)
2001 - 2006	3.3	2.5	1.2	0.1
2006 - 2011	2.5	1.9	1.4	0.5
1991 - 2001	3.8	2.6	0.9	(0.2)
2001 - 2011	2.9	2.2	1.3	0.3
1991 - 2011	3.3	2.4	1.1	0.1

Average Annual Rates of Growth (%)

Washington Sales

	High	Medium High	Medium Low	Low
1991 - 1996	3.7	2.6	1.8	0.9
1996 - 2001	3.9	2.8	1.3	0.4
2001 - 2006	3.3	2.4	1.3	0.2
2006 - 2011	2.9	2.1	1.5	0.4
1991 - 2001	3.8	2.7	1.6	0.6
2001 - 2011	3.1	2.3	1.4	0.3
1991 - 2011	3.5	2.5	1.5	0.5

Pacificorp - Rampp 2 - Sales Forecast

Average Annual Rates of Growth (%)

Idaho (Pacific Division) Sales

	High	Medium High	Medium Low	Low
1991 - 1996	5.7	4.2	1.9	0.7
1996 - 2001	5.6	4.2	2.4	0.7
2001 - 2006	4.8	3.7	2.5	0.5
2006 - 2011	4.3	3.5	2.8	0.7
1991 - 2001	5.6	4.2	2.2	0.7
2001 - 2011	4.5	3.6	2.6	0.6
1991 - 2011	5.1	3.9	2.4	0.7

Average Annual Rates of Growth (%)

Montana Sales

	High	Medium High	Medium Low	Low
1991 - 1996	3.9	2.6	2.2	0.4
1996 - 2001	4.7	3.4	2.0	0.9
2001 - 2006	4.3	3.5	2.0	0.7
2006 - 2011	3.9	3.3	2.2	0.9
1991 - 2001	4.3	3.0	2.1	0.6
2001 - 2011	4.1	3.4	2.1	0.8
1991 - 2011	4.2	3.2	2.1	0.7

Pacificorp - Rampp 2 - Sales Forecast

Average Annual Rates of Growth (%)

California Sales

	High	Medium High	Medium Low	Low
1991 - 1996	4.0	2.4	1.2	(0.1)
1996 - 2001	3.5	2.1	0.8	(0.6)
2001 - 2006	2.9	1.9	0.7	(0.8)
2006 - 2011	2.7	1.8	1.1	(0.5)
1991 - 2001	3.7	2.3	1.0	(0.4)
2001 - 2011	2.8	2.1	1.0	(0.5)
1991 - 2011	3.3	2.1	1.0	(0.5)

Average Annual Rates of Growth (%)

Wyoming (Pacific Division) Sales

	High	Medium High	Medium Low	Low
1991 - 1996	4.6	3.4	2.1	0.7
1996 - 2001	4.5	3.4	1.6	0.6
2001 - 2006	3.9	3.0	1.4	0.2
2006 - 2011	3.1	2.4	1.0	(0.3)
1991 - 2001	4.5	3.4	1.9	0.6
2001 - 2011	3.5	2.7	1.2	0.0
1991 - 2011	4.0	3.1	1.5	0.3

Pacificorp - Rampp 2 - Sales Forecast

Average Annual Rates of Growth (%)

Idaho (Utah Division) Sales

	High	Medium High	Medium Low	Low
1991 - 1996	4.3	3.8	2.6	2.2
1996 - 2001	4.4	4.0	1.0	0.6
2001 - 2006	3.6	3.2	0.7	0.3
2006 - 2011	2.7	2.3	0.7	0.3
1991 - 2001	4.3	3.9	1.8	1.4
2001 - 2011	3.1	2.7	0.7	0.3
1991 - 2011	3.7	3.3	1.3	0.9

Average Annual Rates of Growth (%)

Wyoming (Utah Division) Sales

	High	Medium High	Medium Low	Low
1991 - 1996	4.4	3.0	2.1	(0.3)
1996 - 2001	4.2	2.8	1.5	0.3
2001 - 2006	3.5	2.4	1.3	0.2
2006 - 2011	2.6	1.7	0.7	(0.5)
1991 - 2001	4.3	2.9	1.8	0.0
2001 - 2011	3.1	2.0	1.0	(0.2)
1991 - 2011	3.7	2.5	1.4	(0.1)

Pacificorp - Rampp 2 - Sales Forecast

Average Annual Rates of Growth (%)

Utah Sales

	High	Medium High	Medium Low	Low
1991 - 1996	5.5	4.2	2.2	0.6
1996 - 2001	4.5	3.6	1.5	0.3
2001 - 2006	4.1	3.4	2.0	0.6
2006 - 2011	3.5	2.8	1.9	0.7
1991 - 2001	5.0	3.9	1.8	0.4
2001 - 2011	3.8	3.1	2.0	0.6
1991 - 2011	4.4	3.5	1.9	0.5

ECONOMIC & DEMOGRAPHIC SECTION

Employment

Basic Employment

Within the Company's forecasting methodology, employment serves as a major determinant of future trends among the economic and demographic variables used to "drive" the sales forecasting equations. Recognition of the importance of employment determination can be understood through the examination of the concept of "regional export base theory." This methodology assumes that the local economy is comprised of two distinct sectors: "basic" and "non-basic".

The basic sector is comprised of those industries which are involved in the production of goods destined for sales outside of the local area and whose market demand is primarily determined at the national level. The employment categories that are treated as basic are: manufacturing, mining, agricultural, and federal government. A "regional share" approach is utilized to forecast most of the specific industries that make up the basic employment category. All basic sectors except mining are forecast similarly. For each historic year for which employment data is available a "regional share" is calculated as follows:

$$\text{Regional Share}_{tij} = \text{Employment}_{tij} - \text{Employment}_{t-1ij} \times (\text{National Employment}_{tj}/\text{National Employment}_{t-1j})$$

where: t = current period

i = zone

j = specific employment group (must be either agriculture, federal government, or one of the manufacturing categories.)

Historic regional shares are thus the difference between the actual employment in any year and the projected employment if it had grown at the same rate as national employment.

For forecasting, the equation is inverted. Employment in the current period becomes the dependent variable. The equation then becomes:

$$\text{Employment}_{tij} = \text{Employment}_{t\text{-}1ij} \times (\text{National Employment}_{tj} / \text{National Employment}_{t\text{-}1j}) + \text{Regional Share}_{tij}$$

where: t = current period

i = zone

j = specific employment group (must be either agriculture, federal government, or one of the manufacturing categories.)

The regional shares used in the forecast are allowed to differ from their historic values. (In the two high forecasts, we assume regional shares higher than the historic average, and vice-versa in the low forecasts. We do not assume that, as a matter of consequence, regional growth is faster than the nation in the high forecast, rather, the comparison is between the forecast and historic regional shares, not the absolute growth).

The final basic sector, mining employment, cannot be forecast in the same manner as the other basic sectors. This is because forecasts of mining employment are only available from DRI for total mining employment and hence are not available at the level of disaggregation necessary for the mineral specific equations used to forecast electricity sales.

In general mining employment is forecast as a function of mining employment in the previous period and a regional or national variable representing output or a surrogate for output from the mining category. The equation thus takes the form:

$$\text{Employment}_{ijt} = f(\text{Employment}_{ijt-1}, \text{Output}_{it})$$

where: i = specific mining category

t = current period

j = zone.

Non-Basic Employment

The non-basic sector represents those businesses whose output serves the local market and whose market demand is largely determined by the level of basic employment and output in the local economy. Employment categories that are treated as non-basic are: transportation, communications, and public utilities; wholesale and retail trade; finance, insurance, and real estate; services; contract construction; state & local government; and non-farm proprietors. This simplistic definition of industries as basic or non-basic does not directly confront the problem that some service industry employment (traditionally treated as non-basic) has assumed a more basic nature. This problem is overcome by including variables such as Real Gross National Product, National Output, Housing Starts, a Time Trend, along with basic employment, in the equations which determine the non-basic employment forecasts. These equations are formed by regressing employment in each of the categories as a function of variables which will include some of the following: a lagged dependent variable, basic employment, and the national variables discussed previously. The inclusion of basic employment in the specification is a direct application of regional export base theory. As basic employment increases, it causes the non-basic sector to expand.

The relationship between the basic and non-basic sectors has not been constant over time. This is because as the productivity, and hence real wages, of basic sector workers has increased, their expanded purchasing power has caused the non-basic sector to develop more rapidly. A second reason is the changing preference and tastes of consumers which has caused a relative shift away from the good-producing or basic industries towards those which are more service-oriented. A third reason is that on a locational basis, more non-basic industries are behaving as basic industries.

Within a given sector not all of the state level equations will include all of the independent variables discussed above. The specifications for transportation, communications, and public utilities; wholesale and retail trade; finance, insurance, and real estate; services; state & local government, is:

$$\text{Employment}_{tj} = f(\text{Employment}_{t-1j}, \text{Basic Employment}_{tj}, \text{Real Gross National Product}_{t}, \text{Time}_{t}, \text{Agricultural Employment}_{tj}/\text{Basic Employment}_{tj})$$

where: t = current period

j = zone.

The final specification will include only those variables that statistically indicate a significant impact. Agricultural Employment divided by Basic Employment is used to explicitly model the assertion that changes in agricultural employment have less effect on the non-basic sector than do the other basic employment categories.

The next non-basic category, Contract Construction, does not have Agricultural Employment in the equation specifications. Either National Housing starts or the

Effective Mortgage rate have been included in the specification as a surrogate for local construction activity. Historically, changes in local construction activity have been associated with changes in national housing starts and/or the mortgage rate, a relationship which is expected to continue in the future. The specification is thus:

$$Employment_{tj} = f(Employment_{t-1j}, \text{Basic } Employment_{tj}, \text{National Housing } Starts_t, \text{Effective Mortgage } Rate_t, Time_t)$$

where: t = current period

j = zone.

The final non-basic category, Non-Farm Proprietors, is forecast simply as a function of the sum of the other six non-basic categories.

$$\text{Non Farm } Proprietors_{tj} = f(\Sigma \text{ Other Non-Basic } Employment_{tj})$$

where: t = current period

j = zone.

Population

DRI's Regional Information Service contains long-range forecasts of total population, and total non-agricultural employment for the states served by the Company. Population per non-agricultural employee at the state service territory level is forecast as a function of population per non-agricultural employee at the state level. This ratio is then multiplied by the forecast of non-agricultural employment at the service territory level to derive a population forecast.

$$\text{Service Territory Population}_{tj} = \text{Service Territory Non-Agricultural Employment}_{tj} \times f(\text{State Population}_{tj}/\text{State Non-Agric. Employment}_{tj})$$

where: t = current period

j = zone.

Income

Two primary measures of income are utilized in producing the forecast of total electricity sales. Total personal income is used as a measure of "economic vitality" which impacts energy utilization in the commercial sector. Real per capita income is used as a measure of "purchasing power" which impacts energy choice in the residential sector. The Company's economic forecasting system projects total personal income on a service territory basis.

In order to accurately portray the differing income streams caused by the diversity of the economic base of the service territory, the total personal income forecast is formed from the sum of eight separate components. Four of these measures - manufacturing, mining, agricultural, and non-farm/non-industrial (commercial) income - combine to form labor & proprietors income. This level of disaggregation is necessary in order to capture differences in zonal level trends in various time streams within the Company's service territory which are largely caused by differences in the economic base of the area. The four remaining components of total personal income are contributions for social insurance, transfer payments, property income (dividends, interest and rent) and the net residence adjustment. The relationship among the components can be expressed in the following manner:

Total Personal Income = Labor & Proprietors Income - Contributions for Social Insurance + Property Income + Transfer Payments + Net Residence Adjustment.

Labor & proprietor's income comprises the largest share of personal income. It is primarily comprised of payments to salaried employees, hourly workers and the net income of unincorporated businesses, both farm and non-farm. Forecasts were derived through econometric specifications of the four primary components as previously described. This level of disaggregation allows for a more accurate reflection of the differences in employment patterns and wage & salary structures within each group.

Economic theory suggests that real wage increases will reflect corresponding increases in employee productivity and output. Subsequently, sectoral income can be derived as a function of the level of productivity (output/employee) and output. Equations to forecast commercial and manufacturing income utilized a national productivity index (there being no sub-national index available) in a pooled least squares regression.

The general relationship for these two sectors is:

$$\text{Income}_{tj} = f(\text{Employment}_{tj}, \text{National Productivity}_t)$$

where: t = current period

j = zone.

Within the mining and agricultural sectors, reliable productivity measures which will yield acceptable results when attempting to specify an equation do not exist at the sub-national or national level. This is not surprising considering the specialized nature of the Company's mining and farm sectors. Because of this lack of reliable productivity measures, alternative specifications were sought. A simplistic equation was used to forecast Mining Income. The change in mining income was defined to be equal to the change in mining employment multiplied by the change in national manufacturing productivity. i.e. for the mining sector:

$\text{Income}_{tj} = \text{Income}_{t-1j} \times (\text{Employment}_{tj}/\text{Employment}_{t-1j}) \times$

$(\text{National Manufacturing Productivity}_t/\text{National Manufacturing Productivity}_{t-1})$

where: t = current period

j = zone.

Farm income is specified on a real income per employee basis as a function of national farm proprietor's income per employee. The forecast of farm income will vary with different levels of zonal employment, national income and employment. For the farm sector:

$\text{Income}_{tj} = f(\text{Employment}_{tj}, \text{National Farm Income Per Employee}_t)$

where: t = current period

j = zone.

Contributions for social insurance, are payments made by individuals under the various social insurance programs. They are excluded from personal income through being handled as specific deductions. Forecasts are made for this variable by projecting the percentage of labor & proprietor's income going to social insurance deductions at the local level as a function of the same value at the national level. The equation is:

$$\text{Contributions For Social Insurance}_{tj} = \text{Labor \& Proprietor's Income}_{tj} \times f(\text{National Percentage Contribution for Social Insurance}_{t})$$

where: t = current period

j = zone.

Property income consists of dividends, personal interest income, and royalty income of individuals. It is forecast on a per capita basis as a function of national per capita property income and time. The time variable allows for differing rates of growth of property income at the regional level as compared to the national level. The relationship is:

$$\text{Property Income}_{tj} = \text{Population}_{tj} \times f(\text{National Per Capita Property Income}_{t}, \text{Time}_{t})$$

where: t = current period

j = zone.

Transfer payments consist of the income of persons from government or business for which no services are currently being rendered. Nationally, the largest component of this revenue stream is derived from federal Social Security, Public Assistance and Veterans benefit programs. Similarly to property income, local per capita transfer payments are forecast as a function of the national per capita transfer payments as follows:

$$\text{Transfer Payments}_{tj} = \text{Population}_{tj} \times f(\text{National Per Capita Transfer Payments}_t)$$

where: t = current period

j = zone.

Finally the net residence adjustment (the net difference between income earned by an area's residents outside the area, and income received by non-residents inside the area) is projected to continue as a constant percentage of personal income into the future.

ENERGY SECTION

Introduction

One of the most important characteristics of an integrated resource plan is the fair evaluation of both supply-side and demand-side resources in building an overall portfolio designed to meet future electricity growth. In order to put increased demand efficiencies on an equal footing with supply-side resources, the retail sales forecast is developed using the "frozen efficiencies" concept. This means that important elements that constitute an individual customer's total electricity consumption, and average appliance usages (except those where new government standards have or will be implemented in the near future), are held at their 1990 levels throughout the forecast period. New customers which are added during the forecast period are assumed to meet current codes, or to meet Model Conservation Standards.

Residential Sales

The Company's Residential End-Use Forecasting Model has been developed to forecast specific uses of electricity in the customer's home. It is a hybrid econometric-enduse model. The model explicitly considers factors such as persons per household, fuel prices, per capita income, housing structure types, and other variables that influence residential customer demand for electricity. Residential demand is projected on the basis of fourteen end-uses. These uses are space heat, water heat, electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs, well pumps, & residual uses. Air conditioning can be either central, window, or evaporative (swamp cooler).

The basic structure of the end-use model is to multiply forecast appliance saturations (percentage of homes with a particular appliance) by the appropriate housing stock. The result is then multiplied by the annual average electricity usage per appliance. The product, total annual electricity consumption by residential usage, is shown by the following equation:

$$\text{Total Appliance Consumption}_i = \Sigma \text{ Housing Stock}_k \times \text{Saturation of Appliance}_{ik} \times \text{Electricity Usage of Appliance}_{ik}$$

where: i = Appliance type

k = Housing type.

Because consumption patterns vary with dwelling type and age, the residential model identifies three types of structures - single family, multi-family, and mobile homes - each comprised of existing and new homes. In addition, for existing homes, the single families are subdivided into three sizes of dwellings. For new houses, in addition to subdividing single family households, multi-families dwellings are also broken down into two different size groupings. Single family homes are defined as containing only one household and having an exterior exposed to the elements on all sides. Multiple family homes are defined as both traditional multiple unit dwellings such as apartment buildings, duplexes and triplexes, and any single family units that are attached on at least one side to other structures. Mobile homes are defined as all structures built initially upon a trailer chassis.

DRI's Regional Information Service contains long-range forecasts of total population, and households for the states served by the Company. The ratio of total residential customers to population at the state service territory level is forecast as a function of the ratio of households to population at the state level. (This specification assumes that the historic relationship between the state service territory and the entire state continues into the future. While this is not certain, it is probable that the range of employment forecasts from the high to the low will generate a wide range of customer forecasts). This ratio is then multiplied by the forecast of population at the service territory level to derive a forecast of total residential customers. The equations look like:

$$\text{Residential Customers}_{tj} = \text{Service Territory Population}_{tj} \times f(\text{State Households}_{tj}/\text{State Population}_{tj})$$

where: t = current period

j = zone.

To project the number of new residential customers, an estimation of the demolition rate for existing buildings must be made. These rates are constructed from historic Company data and refer to the changes in the number of active customer accounts for whatever reason. The demolition rates are state specific for each structure type because the composition of the existing housing stock in each state is different and is subject to differing influences. It is assumed that the mobile homes as a group would be demolished at a higher rate than the multi-family structures, which would in turn be demolished at a higher rate than single family structures. The equation for new residential customers for each structure type and zone is thus:

$$\text{New Residential Customers}_{ijt} = \text{Total Residential Customers}_{ijt} - (1 - (\text{Demolition Rate}_{ij}))^{t} * (\text{Total Residential Customers}_{ij0})$$

where: t = current period

j = zone

i = structure type.

The distribution of existing residential customers among the various different types and sizes of structures is based upon survey data. The preference of new residential customers for different structures types is based upon econometric equations modeled on historical new connect information. The size distribution within the differing structure types is based upon survey data.

The percentage of the total number of residential customers (households) expected to choose a particular heating type or appliance in the future (the saturation of the appliance) is estimated with an econometric equation containing such variables as electricity price, income, & the price of competitive fuels. (The saturation for each appliance in the first year of the forecast (1990) is based upon estimates developed from Company survey data.) This approach is used for all of the end-uses except space and water heat where the percentage of the total number of **new** residential customers expected to choose electric space or water heat in the future (the penetration of the end use) is estimated with an econometric equation containing such variables as electricity price, income, & the price of competitive fuels.

In general, saturations and penetrations are calculated econometrically using logistic formulations. A logistic equation takes the following form:

$$(\text{Saturation})/(1 - \text{Saturation}) = F(\text{Real Prices, Income,...})$$

The logistic specification contains two properties which make it especially useful for analysis:

1. The saturation of the forecast variable is constrained between 0 & 100 percent. With the exception of such appliances as refrigerators and televisions,

this is an obvious constraint.

2. The magnitude of the response of the saturation to a change in electric price depends upon where the saturation of the appliance is when the change in electric price occurs. This property is known as variable elasticity. The implication is that the higher the saturation, the same absolute change in price will have less effect upon the change in saturation.

Electric space heat penetrations are forecast on an annual basis using econometric equations in logistic form. The penetrations are calculated for each structure type for each zone. The basic form of the equation is:

$$\text{Logit(Space Heat Penetration}_{ijt}) = f(\text{Logit(Space Heat Penetration}_{ijt-1}), \text{Real Electricity Price}_{ijt}/\text{Real Fossil Price}_{ijt})$$

where: t = current period

j = zone

i = structure type.

Real electricity prices are divided by a weighted average of real fossil fuel prices to obtain relative prices in the residential sector. The forecast penetration rate is multiplied by the number of newly constructed dwelling units to obtain the actual number of new electrically heated homes. To this figure is added the number of existing electric space heat units, less demolitions, to give the total number of electrically heated units in any given year.

The number of water heat customers is forecast in a similar fashion, modified by the fact of the shorter life time of a water heater as compared to the lifetime of the house. It is assumed that the average life of a water heater is 15 years. Each year, water heat penetrations are calculated for the new dwellings plus 1/15th of the remaining existing buildings. The equations take the form:

$$\text{Logit(Water Heat Penetration}_{ijt}) = \text{f(Logit(Non-Natural Gas Space Heat Penetration}_{ijt}))$$

where:
t = current period
j = zone
i = structure type.

This logistic formulation assumes that all non-gas space heat new connects will install electric water heaters. The form of the equation allows only natural gas space heat connects to install natural gas water heaters, and at the same time, constrains electric water heat penetrations to be less than 100%. As with space heat, the houses with new electric water heaters are added to the number of houses with old electric water heaters to yield the total number of homes with water heaters.

After calculating penetration rates for space heat & water heat, saturations are estimated for the other major appliances - electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs & well pumps. Logistic econometric equations are used to estimate most appliance saturations.

The equations which forecast the saturations for the three types of air conditioners takes the following form:

$$\text{Logit}(\text{Air Conditioning Saturation}_{ijt}) = f(\text{Logit}(\text{Air Conditioning Saturation}_{ijt-1}), \text{Real Electricity Price}_{jt})$$

where: t = current period

j = zone

i = central (c), window (w), swamp cooler (s).

and $\text{Saturation}_{cjt} + \text{Saturation}_{wjt} + \text{Saturation}_{sjt} \leq 1$

for all j & t.

The equations which forecast the saturations for electric clothes dryers take the form:

$$\text{Logit}(\text{Clothes Dryers Saturation}_{jt}) = f(\text{Logit}(\text{Clothes Dryers Saturation}_{jt-1}), \text{Real Electricity Price}_{jt}/\text{Real Fossil Price}_{jt}, \text{Real Per Capita Income}_{jt}, \text{Gross National Product}_{t})$$

where: t = current period

j = zone.

The assumption is made that all homes having a clothes dryer will also have a clothes washer, the equations that forecast clothes washers therefore take the form:

$\text{Logit}(\text{Clothes Washers Saturation}_{jt}) = f(\text{Logit}(\text{Clothes Dryers Saturation}_{jt}),$

where: t = current period

j = zone.

and: Clothes Washers Saturation $\geq$ Clothes Dryers Saturation.

The equations which forecast the saturations for Dishwashers take the form:

$$\text{Logit}(\text{Dishwasher Saturation}_{jt}) = f(\text{Logit}(\text{Dishwasher Saturation}_{jt-1}), \text{Real Electricity Price}_{jt}, \text{Real Per Capita Income}_{jt})$$

where: t = current period

j = zone.

The equations which forecast the saturations for Freezers take the form:

$$\text{Logit}(\text{Freezer Saturation}_{jt}) = f(\text{Logit}(\text{Freezer Saturation}_{jt-1}), \text{Real Electricity Price}_{jt}, \text{Real Gross National Product}_{t})$$

where: t = current period

j = zone.

The equations which forecast the saturations for electric ranges take the form:

$$\text{Logit}(\text{Range Saturation}_{jt}) = f(\text{Logit}(\text{Range Saturation}_{jt-1}), \text{Real Electricity Price}_{jt}, \text{Real Per Capita Income}_{jt}, \text{Time}_{t})$$

where: t = current period

j = zone.

Insufficient historical data is available to accurate forecast the saturations of water beds and well pumps. They are therefore held constant at their most recent historical level. The saturations levels for refrigerators, lighting and residual uses is set equal to one throughout the forecast period.

After forecasting the total number of existing and new residential customers; the distribution of them within the various structure types; and the number of them that have the various appliances; the final step is to calculate consumption levels for each of the various appliances.

Average consumption for each of the five existing structures types for space heat usage are estimated using a conditional demand approach. These numbers have embedded in them a level of wood heat consumption. Assumptions upon the rate and level at which wood space heat usage is displaced by electric space heat usage varies between the four scenarios. In the high scenario, all wood heat users convert to electric space heat within the first five years of the forecast. In the medium-high forecast, all wood heat users convert to electric space heat within the forecast period. In the medium-low forecast, half the wood heat users convert to electric space heat within the forecast period. In the low forecast, the wood heat consumption continues at the existing level. Average consumption for water heat in existing homes is also calculated using a conditional demand approach. As these water heaters are replaced with new water heaters, there consumption levels are the same as those in new residential dwellings.

Average consumption for future space heat and water heat usage are estimated using the prototypical residential models. If a state has enacted Energy Standards, or is expected to enact standards close to Model Conservation Standards, the space heat usage consistent with MCS are assumed for future space customers. For states which have not enacted MCS, houses are built to present Energy Standards. These usage levels are the basis upon which the conservation supply curves are based.

Usage for other appliances are estimated based upon generally accepted institutional, industry and engineering standards. If it is known that Governmental Standards will require that appliances be built to a higher efficiency than at present, that assumption is built into the forecast.

The forecast resulting from all of the preceding assumptions is referred to as a "Frozen Efficiency" forecast, although technically, the efficiencies are not frozen at present levels, but changed to reflect known intervention in the marketplace by the government and other institutional agencies. These usage numbers are input into the prototypical residential models used to develop the conservation supply curves. This determines that there is a consistency between the numbers used in developing the load forecast and those used in developing the conservation supply curves. For each of the four scenarios, and for each of the forecast years, forecasts of existing and new space and water heat customers, and forecasts of the total number of residential customers using the appliances described above is passed to the supply curves. Once these numbers have been input, forecasts of conservation that customers will perform upon their own initiative are calculated and the results input into the load forecasting model. The residential sales forecast resulting from this calculation, is the level of residential sales that is used in making resource decisions. The prototypical residential buildings consist of five types for existing homes (three single family, multi-family, mobile homes), and six types for new homes (three single family, multi-family, two mobile homes).

The estimates of base year saturations and base year usages are combined so that they conform to the actual customer sales history for the base year (1990). All historic sales data is temperature adjusted.

Commercial Sales

The commercial model, like the residential model, is a hybrid econometric-enduse model. The model forecasts electric energy use per square foot for each of seven enduses for twelve commercial activities for each of the nine zones served by the Company. The seven end-uses are space heating, water heating, space cooling, ventilation,cooking, lighting, & miscellaneous uses. Air conditioning can be either central, window, or evaporative (swamp cooler). Twelve vertical market segments (building types or commercial activities) are modeled: Communications/Utilities/Transportation, Food Stores, Retail Stores, Restaurants, Wholesale Trade, Lodging, Schools, Hospitals, Other Health Services, Offices, Services, and a miscellaneous category.

Each of the twelve vertical market segments are defined based upon Standard Industrial Classifications (SIC). The basic structure of the end-use model is to multiply forecast enduse saturations (percentage of square foot with a particular enduse) by the appropriate amount of square foot. The result is then multiplied by the annual average electricity usage per square for each enduse. The product, total annual electricity consumption by commercial enduse, is shown by the following equation:

$$\text{Total Consumption}_i = \Sigma \text{ Square Foot}_k \times \text{Saturation of Appliance}_{ik} \times \text{Electricity Usage of Appliance}_{ik}$$

where: i = Enduse

k = Vertical Market Segment.

Employment is the major determinant of change in the commercial sector. While the growth in a particular activity will be caused by locational advantages, local real estate prices, tax policy, zoning ordinances, long term interest rates, and a myriad of other variables, growth for each particular commercial activity is estimated using employment in that commercial activity as a proxy variable. The theoretical appeal of employment is that it tends to travel the same paths of growth and decline as that of a vast array of coincident commercial indicators. On a more practical note, the availability and depth of employment data far surpasses other types of qualitative and quantitative data.

Forecasts of employment for each of the major commercial employment categories (at the 1 digit SIC level) need to be allocated to the twelve building types (which combines 2,3 & 4 level SIC). This information is not available at the state service territory level. It is assumed that the distribution of employment at the state level (from DRI's Regional Service) does not differ from that at the state service territory level and employment is thus allocated in this manner.

Although as mentioned previously, changes in floorspace will not exactly follow changes in employment, we have had to make the simplistic assumption that total floorspace per employee will remain constant in the future. (The Company is presently involved in performing a commercial survey, which once combined with an earlier survey, may allow a better of understanding of how floorspace per employee has changed historically.) Each activity has a demolition rate (derived from Company records) which retires buildings. This does not mean that all "demolitions" are felled by wrecking crews. The model accepts the implied re-entry, to the commercial market, of buildings that have been at least partially renovated and now hold a different function in the commercial sector. Once we have forecast total square foot in each vertical market segment, and the amount of square foot remaining of the presently (1990) existing square foot, the amount of new square foot is determined to be the difference of the two numbers, i.e.

$$\text{New Commercial Square Foot}_{ijt} = \text{Total Commercial Square Foot}_{ijt} - (1 - (\text{Demolition Rate}_{ij}))^{t} * (\text{Total Commercial Square Foot}_{ij0})$$

where: t = current period

j = zone

i = vertical market segment.

Base year (1990) saturations levels and usage per square foot for each of the commercial end uses have been estimated using data from commercial surveys, commercial customer consumption data, and engineering estimates. These estimates of saturations and usages may be slightly modified so that when they are combined with the estimates of base year square feet, the resulting estimate of electricity sales agrees with the actual temperature adjusted electricity sales to each of the building types (for each state) in 1990.

The commercial model forecasts the saturation of three end-uses, space heating, water heating, and space cooling. Ventilation, lighting, & miscellaneous uses are assumed as 100% electrically powered over the forecast period. Those vertical market segments that are refrigerated are also assumed to have a saturation of 100%. As in the residential sector, the saturations are forecast using a logistic specification. The equations take the form:

$$\text{Logit}(\text{Enduse Saturation}_{ijkt}) = f(\text{Logit}(\text{Enduse Saturation}_{ijkt-1}), \text{Real Electricity Price}_{ijt}/\text{Real Fossil Fuel Price}_{jt}, \text{Real Time}_t, \text{Gross National Product}_t)$$

where: t = current period

j = zone.

i = vertical market segment

k = space heating, space cooling, water heating.

Usage per square foot for each enduse for existing buildings are frozen at their 1990 level during the forecast period. Usage per square foot for new buildings has been estimated using engineering models and assuming current practices - these estimates are similarly frozen throughout the forecast period.

Once again, the forecast resulting from these assumptions is a Frozen Efficiency forecast. These usage numbers are input into the prototypical commercial models used to develop the conservation supply curves. This determines that there is a consistency between the numbers used in developing the load forecast and those used in developing the conservation supply curves. For each of the four scenarios, and for each of the forecast years, forecasts of existing and new square foot for each of the twelve building types is passed to the supply curves. Once these numbers have been input, forecasts of conservation that customers will perform upon their own initiative are calculated and the results input into the load forecasting model. The commercial sales forecast resulting from this calculation, is the level of commercial sales that is used in making resource decisions.

Forecasts of commercial customers are developed by summing the new and existing square foot numbers and dividing by the average square foot/customer (specific to each VMS and zone).

Industrial Sales

Unlike many other electric utilities, Pacific's industrial sector is not dominated by a small number of firms or industries. During 1990, the Company's largest industry (combining sales in both divisions), oil and gas exploration accounted for only 20% of total industrial sales. The heterogeneous mix of customers and industries, combined with their widely divergent electricity consumption characteristics per unit of output, indicates a substantial amount of disaggregation in developing a proper forecasting model for this sector. Accordingly, the industrial sector has been heavily disaggregated within the manufacturing and mining customer segments. The manufacturing sector is broken down into ten categories based upon the Standard Industrial Classification Code System. These categories are Food Processing (SIC 20), Lumber & Wood Products (SIC 24), Paper & Allied Products (SIC 26), Chemicals & Allied Products (SIC 28), Petroleum Refining (SIC 29), Stone, Clay & Glass (SIC 32), Primary Metals (SIC 33), Electrical Machinery (SIC 36), Transportation Equipment (SIC 37). In all states, sales to a residual manufacturing category (all remaining manufacturing SIC codes) are forecast. Forecasts are only made for the major SICs within a particular zone, when sales to that SIC within a zone are significant. Thus the definition of residual manufacturing is zonal specific.

The mining industry, located primarily in Wyoming and Utah, has also been subject to a significant level of disaggregation. Separate forecasts have been completed for the following industries: Coal Mining (SIC 12), Oil & Natural Gas Exploration, Pumping, & Transportation (SIC 13), Non-Metallic Mineral Mining (SIC 14); there also exists an "other" mining categories in a few zones.

The industrial sector is modeled using an econometric forecasting system. Conceptually, the best method of forecasting electricity sales would be on a per unit of output basis. However this information is not available at the state service territory level. Accordingly sales are forecast on a per employee basis. Therefore electricity sales per employee are regressed in equations which may contain the following independent variables: a lagged dependent variable, relative price (or electricity price & fossil fuel prices), national output in the industry, a time trend... Not all equations will contain all the independent variables. The resulting ratio is forecast and multiplied by the forecast of employment to arrive at the forecast of industrial electricity sales.

The disaggregated industrial sector allows the composition of industry mix to vary over time. Each's industry's employment is forecast to grow at a different rate and significant differences exist in both the level and trend of energy consumption per employee. Each industry also varies considerably in the magnitude of its response to changes in electricity and fossil fuel prices. Only with a disaggregated model can these differences be explicitly analyzed.

Breaking the industries' electricity consumption forecasts into two pieces, employment and megawatthour consumption per employee, and then multiplying them together to arrive at total consumption, allows for the explicit estimation of two distinct actions: changes in employment, and the intensity of use per employee.

The employment forecasts are been described earlier in this document. The forecasts of intensity of use per employee are based upon the effect that in the long run, capital stock, utilization rates, and technology are not fixed. Electricity use per employee will either increase or decrease as investments are made that substitute more or less electricity for all other factors of productions. This effect is captured by the inclusion of a lagged dependent variable, real electricity prices, and real fossil fuel prices in the electricity use per employee equations.

The sign of the electricity price coefficient in the equations is positive and its interpretation is straightforward; electricity conservation activities take places in response to rising electricity prices and tends to decrease the intensity of electricity use. The fossil fuel price coefficient is negative and captures the impact of a change in sales per employee caused by the substituting fossil fuels for electricity. Having a lagged dependent variable in the equation allows for the gradual adjustment in consumption patterns, by each industry, as a result of changes in the real price of electricity and fossil fuels. Business firms cannot react immediately to new price conditions. Major changes can only occur over time as older, less efficient machinery and factors are replaced with newer and more productive ones. There are many other factors which could have been included in the industrial sales per employee equations. The costs of labor and capital have theoretical implications as prices of substitutes or complements for electricity use. The use of real weekly wages and estimates of capital costs were included in early equation specifications but the results were unacceptable. Real Gross National Product, National Output & a Time Trend have been used as proxies for these variables.

In particular the equations for Food Processing (SIC 20) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt}, \text{National Output}_{t})$$

where: t = current period

j = zone.

The equations for Lumber & Wood Products (SIC 24) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt}, \text{National Output}_{t}, \text{Real Mortgage Rate}_{t})$$

where: t = current period

j = zone.

The equations for Paper & Allied Products (SIC 26) & Chemicals & Allied Products (SIC 28) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{National Output}_{t})$$

where: t = current period

j = zone.

The equations for Petroleum Refining (SIC 29) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}, \text{Real Gross National Product}_{t}, \text{National Output}_{t})$$

where: t = current period

j = zone.

In particular the equations for Stone, Clay & Glass (SIC 32) are represented as:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}, \text{Real Fossil Fuel Price}_{jt})$$

where: t = current period

j = zone.

In particular the equations for Primary Metals (SIC 33) take the form

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt}, \text{Time}_{t})$$

where: t = current period

j = zone.

The equations for Electrical Machinery (SIC 36) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}, \text{National Output}_{t})$$

where: t = current period

j = zone.

The equations for Transportation Equipment (SIC 37) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}, \text{Time}_{t})$$

where: t = current period

j = zone.

Finally, the equations for the residual manufacturing sales category take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1},$$
$$\text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt},$$
$$\text{National Output}_{t}, \text{Time}_{t})$$

where: t = current period

j = zone.

Sales to three major mining categories are specified using econometric techniques. The equations for Coal Mining (SIC 12) have the specification:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1},$$
$$\text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt},$$
$$\text{Real Gross National Product}_{t})$$

where: t = current period

j = zone.

The second major mining category - Oil & Natural Gas Exploration, Pumping, & Transportation (SIC 13) is specified as follows:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1},$$
$$\text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt})$$

where: t = current period

j = zone.

The final major mining category is Non-Metallic Mineral Mining (SIC 14). The equations for this category are:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1},$$
$$\text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt,}$$
$$\text{National Output}_{t}, \text{Real Gross National Product}_{t})$$

where: t = current period

j = zone.

Forecast of electricity sales, for each of the four scenarios, are passed to the supply curves, once again assuring consistency between the models. It is assumed that all background conservation measures will be picked up by the forecasting equations and that the conservation is already embedded in the forecast. Therefore the sales passed to the conservation curves and those used in resource decisions are the same sales forecast.

Other Sales

The other sectors to which electricity sales are made are: irrigation, street & highway lighting, interdepartmental and "other sales to public authorities."

Electricity sales to the these smaller customer categories are either forecast using econometric equations or the sales are held constant at historic levels.

Monthly System Peak and Energy

After the annual sales forecast has been completed for each of the customer classes, the results are summed to develop a forecast of total sales for each of the nine zones, the Pacific & Utah Divisions and the Total Company.

An annual system input forecast is developed by adding estimates of system losses (the amount of electricity lost between the point of generation and the customer) to the sales forecasts results. These estimates of system losses are based upon an engineering model developed for the merged company. The estimates are developed for each customer class and zone. The annual energy is broken into monthly data on the basis of historic seasonal patterns specific to each zone. These historic patterns will vary after demand side resources are added and are so reflected in the final sales estimates emerging from the RIM model.

Historic monthly load factors are used in developing coincidental and non-coincidental monthly peak forecasts. These load factors are based on merged Company data.

Public Process

The RAMPP-2 Advisory Group (RAG) was an active participant in the development of this least cost plan. Eleven all-day meetings were held with the RAG group plus two subgroup meetings which focused on Load Forecasting. These subgroup meetings were a great help in determining the forecasts used in this Least Cost Plan. There is a great wealth of detail underlying the forecast (both actual detailed forecast results and statistical parameters) which can only be discussed thoroughly in such a focused forum. We hope that this process will continue through the RAMPP-3 process and actively welcome (at any time) input into how the models can be improved and enhanced.

Statistical Philosophy

A major technique used in the production of the Load Forecasting models has been "Least Squares Regression." In this technique, the dependent variable (the one we which to forecast) is historically regressed against a set of independent variables. Once an equation has been specified, forecast values of the independent variables are used to produce a forecast of the dependent variable.

It should be realized that there is no one perfect equation for any dependent variable. The equation chosen, is in the final instance, one chosen by the analyst. However there are certain statistical parameters that can assist the analyst. Indeed there are too many. Listing all the statistics for all of the variables and equations used in the generation of this forecast would have led to the production of an unwieldy document. Rather than do this, the following principles have been used in the production of the models.

The first is that the relationship between the dependent and independent variable is theoretically correct. (E.G. The relationship between electricity sales and electricity prices should be a negative one.) This means that if statistics indicate a variable should be contained in an equation, a wrong sign on the coefficient would have led to its automatic rejection.

Among the myriad number of statistics associated with any equation, we have chosen to forecast on three statistics.

The first is the Student's 't' statistic. This statistic is associated with each independent variable and a sweeping generalization is that if the absolute value of the 't' statistic is greater than two, than the variable should be included in the equation.

The second statistic is the R^2 for the equation. Each equation specification has associated with it an R^2 statistic. The higher the R^2 and the closer to one, the better the equation specification. (In the vast majority of cases the R^2 was greater than 0.8).

Thirdly the Durbin-Watson statistic (the Durbin 'H' statistic if one of the independent variables is the lagged dependent variable) tests for autocorrelation and the equation specification is corrected as indicated.

Anticipated Changes and Enhancements

The models used in the RAMPP II sales forecasting process are an expansion of those used in the original RAMPP forecast for the Pacific Division. The following are improvements that we hope to make before and during RAMPP III.

Enhance the commercial square foot forecasting methodology to produce more detailed estimates of new construction square footage. The weakest part of the entire model has been the availability of commercial square foot data. The residential model does not have this problem as it forecasts residential customers for which we have good historic values. The industrial model forecasts sales numbers directly and thus does not have this problem.

The merging of the two companies means that system peak forecasts will have greater importance. Therefore of major import, will be to improve the system peak forecasting capabilities, incorporating available data from load research. It is anticipated that these enhancements will include, but will not be restricted to, the use of coincidental factors as opposed to load factors, consideration of class loads, and the incorporation of data from large industrial customers.

Development of hourly load forecasts. As the system becomes more peak constrained and we wish to test new load control programs, hourly load forecasts will become necessary.

Improve the fuel choice and fuel switching capabilities of the residential model.

DETAILED ANNUAL SALES FORECASTS

BY CUSTOMER CLASS BY ZONE

Pacificorp - RAMPP 2 - High Sales Forecast

Pacific Division - Oregon (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	4,847,176	3,359,488	3,799,668	333,085	12,339,417
1992	5,012,505	3,497,609	3,989,354	340,535	12,840,004
1993	5,145,238	3,667,226	4,105,593	346,856	13,264,912
1994	5,306,009	3,843,227	4,186,521	353,209	13,688,966
1995	5,524,217	4,032,133	4,285,585	360,746	14,202,682
1996	5,761,265	4,227,248	4,439,880	369,146	14,797,539
1997	5,989,415	4,410,111	4,585,877	377,020	15,362,424
1998	6,193,365	4,585,507	4,755,623	384,569	15,919,063
1999	6,419,661	4,784,628	5,001,798	393,409	16,599,496
2000	6,639,306	4,992,321	5,229,306	401,893	17,262,825
2001	6,831,144	5,194,273	5,483,243	410,042	17,918,702
2002	7,030,086	5,384,102	5,733,355	417,988	18,565,532
2003	7,260,191	5,567,432	5,973,205	426,072	19,226,899
2004	7,477,025	5,733,116	6,212,172	433,661	19,855,974
2005	7,683,301	5,898,287	6,454,989	441,037	20,477,614
2006	7,904,553	6,056,150	6,669,223	448,170	21,078,097
2007	8,123,441	6,209,569	6,836,778	454,705	21,624,493
2008	8,357,740	6,361,236	6,983,099	461,154	22,163,229
2009	8,616,737	6,511,905	7,114,896	467,704	22,711,242
2010	8,881,458	6,662,369	7,252,464	474,306	23,270,597
2011	9,149,444	6,805,917	7,384,102	480,762	23,820,225
2012	9,398,003	6,930,601	7,452,671	486,183	24,267,458

Pacific Division - Washington (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	1,417,417	1,014,476	811,580	156,670	3,400,144
1992	1,456,539	1,054,456	869,042	159,918	3,539,956
1993	1,486,470	1,097,043	912,116	162,630	3,658,259
1994	1,522,825	1,140,242	951,156	165,361	3,779,584
1995	1,568,903	1,185,392	993,584	168,373	3,916,252
1996	1,645,340	1,229,667	1,037,856	171,997	4,084,860
1997	1,722,479	1,272,527	1,079,528	175,473	4,250,006
1998	1,791,091	1,314,857	1,123,521	178,738	4,408,206
1999	1,864,268	1,362,492	1,182,648	182,446	4,591,854
2000	1,931,945	1,411,774	1,237,463	185,918	4,767,100
2001	2,000,100	1,461,380	1,288,024	189,256	4,938,760
2002	2,073,584	1,510,705	1,333,052	192,523	5,109,865
2003	2,154,516	1,559,167	1,376,327	195,822	5,285,832
2004	2,236,259	1,606,050	1,418,966	199,036	5,460,311
2005	2,313,682	1,651,836	1,461,382	202,095	5,628,995
2006	2,398,372	1,698,350	1,511,409	205,383	5,813,515
2007	2,481,948	1,744,022	1,554,610	208,461	5,989,041
2008	2,569,869	1,788,646	1,595,266	211,505	6,165,287
2009	2,664,271	1,831,681	1,634,134	214,555	6,344,641
2010	2,759,934	1,873,704	1,676,956	217,630	6,528,224
2011	2,854,333	1,913,077	1,720,289	220,602	6,708,300
2012	2,944,825	1,948,477	1,752,101	223,216	6,868,618

Pacificorp - RAMPP 2 - High Sales Forecast

Pacific Division - Idaho (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	101,582	63,708	61,607	735	227,631
1992	106,083	67,112	65,007	735	238,937
1993	109,431	70,987	70,368	735	251,521
1994	113,179	75,170	76,715	735	265,799
1995	118,191	79,786	83,466	735	282,177
1996	124,397	84,794	89,662	735	299,588
1997	130,757	90,009	94,170	735	315,670
1998	137,018	95,479	99,985	735	333,216
1999	143,752	101,479	107,405	735	353,370
2000	150,314	107,840	115,390	735	374,279
2001	156,941	114,431	122,143	735	394,249
2002	164,107	121,151	128,131	735	414,124
2003	172,086	128,006	134,658	735	435,485
2004	180,073	134,848	139,262	735	454,917
2005	188,145	141,881	146,308	735	477,069
2006	196,624	148,946	151,262	735	497,568
2007	205,220	156,073	156,918	735	518,945
2008	214,225	163,251	163,408	735	541,619
2009	223,814	170,455	170,486	735	565,490
2010	233,557	177,752	177,430	735	589,474
2011	243,621	185,141	184,076	735	613,573
2012	253,509	192,419	189,455	735	636,118

Pacific Division - Montana (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	307,464	216,355	206,805	4,012	734,635
1992	319,451	228,238	214,237	4,012	765,938
1993	327,268	241,183	224,874	4,012	797,336
1994	333,906	254,093	232,249	4,012	824,259
1995	343,703	267,860	238,667	4,012	854,242
1996	356,017	281,575	247,629	4,012	889,233
1997	368,359	294,759	257,575	4,012	924,705
1998	380,102	308,028	272,401	4,012	964,543
1999	393,238	322,969	295,980	4,012	1,016,199
2000	405,588	338,506	319,910	4,012	1,068,016
2001	417,897	353,928	343,855	4,012	1,119,692
2002	431,090	369,193	367,502	4,012	1,171,796
2003	446,372	384,567	395,740	4,012	1,230,691
2004	460,879	399,256	408,291	4,012	1,272,438
2005	475,581	414,376	435,734	4,012	1,329,702
2006	491,076	429,466	457,090	4,012	1,381,644
2007	507,512	444,969	483,017	4,012	1,439,510
2008	525,246	460,856	499,386	4,012	1,489,500
2009	544,805	477,187	517,720	4,012	1,543,724
2010	564,692	493,837	545,095	4,012	1,607,636
2011	584,734	510,449	574,577	4,012	1,673,773
2012	603,888	526,390	593,430	4,012	1,727,719

Pacificorp - RAMPP 2 - High Sales Forecast

Pacific Division - California (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	349,395	217,204	91,581	86,891	745,071
1992	362,961	227,060	98,473	90,109	778,603
1993	374,502	238,435	103,983	93,119	810,039
1994	385,604	250,166	106,812	95,841	838,423
1995	399,596	262,601	110,767	98,978	871,941
1996	416,486	275,333	114,707	102,378	908,903
1997	432,924	287,751	115,912	105,420	942,007
1998	447,620	299,659	117,010	108,217	972,506
1999	463,558	312,754	121,147	111,486	1,008,945
2000	478,522	326,269	124,370	114,597	1,043,758
2001	491,965	339,692	127,002	117,485	1,076,144
2002	506,602	352,784	129,346	120,399	1,109,131
2003	524,071	365,789	132,971	123,636	1,146,468
2004	540,189	378,130	134,011	126,450	1,178,781
2005	554,798	390,354	136,414	129,220	1,210,786
2006	570,939	402,346	136,904	131,918	1,242,108
2007	587,323	414,173	138,470	134,695	1,274,661
2008	604,814	425,956	140,933	137,614	1,309,317
2009	624,085	437,744	144,464	140,751	1,347,043
2010	643,352	449,547	148,138	143,876	1,384,913
2011	662,182	461,004	151,699	146,906	1,421,791
2012	679,505	471,380	153,366	149,550	1,453,801

Pacific Division - Wyoming (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	711,945	856,161	4,645,756	22,875	6,236,737
1992	733,065	901,025	4,840,994	22,998	6,498,082
1993	746,222	945,397	5,140,543	23,161	6,855,323
1994	762,007	990,315	5,420,344	23,310	7,195,975
1995	784,539	1,037,427	5,625,765	23,426	7,471,158
1996	814,452	1,086,646	5,867,798	23,558	7,792,454
1997	846,423	1,137,512	6,125,449	23,693	8,133,078
1998	877,405	1,190,881	6,395,716	23,830	8,487,831
1999	910,010	1,247,506	6,709,554	23,980	8,891,050
2000	942,997	1,306,560	7,019,718	24,124	9,293,399
2001	978,151	1,367,658	7,341,403	24,270	9,711,481
2002	1,017,656	1,430,432	7,657,437	24,410	10,129,936
2003	1,062,830	1,494,532	7,954,850	24,543	10,536,755
2004	1,109,838	1,559,466	8,239,906	24,669	10,933,879
2005	1,158,790	1,625,722	8,511,361	24,788	11,320,661
2006	1,208,925	1,694,029	8,814,101	24,914	11,741,969
2007	1,260,481	1,763,565	9,095,198	25,031	12,144,276
2008	1,315,345	1,834,233	9,351,878	25,140	12,526,596
2009	1,374,363	1,905,590	9,591,511	25,243	12,896,708
2010	1,434,409	1,978,137	9,832,112	25,345	13,270,002
2011	1,496,652	2,052,259	10,074,479	25,446	13,648,836
2012	1,561,125	2,127,776	10,292,719	25,539	14,007,159

Pacificorp - RAMPP 2 - High Sales Forecast

Utah Division - Idaho (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	537,405	185,059	1,770,458	574,381	3,067,303
1992	548,298	192,968	1,884,494	589,766	3,215,526
1993	555,482	202,012	1,997,817	604,395	3,359,706
1994	565,765	211,612	2,096,061	617,428	3,490,865
1995	581,694	221,848	2,191,441	630,559	3,625,542
1996	602,838	232,601	2,300,301	645,435	3,781,175
1997	624,943	243,321	2,401,833	659,316	3,929,412
1998	645,578	254,026	2,504,390	672,862	4,076,857
1999	667,387	265,830	2,661,893	691,769	4,286,880
2000	688,352	278,172	2,816,197	709,837	4,492,558
2001	707,816	290,767	2,966,684	726,984	4,692,251
2002	729,725	303,408	3,100,504	742,440	4,876,077
2003	754,666	316,112	3,223,071	756,851	5,050,700
2004	779,771	328,683	3,345,616	770,990	5,225,060
2005	803,910	341,378	3,453,229	783,517	5,382,034
2006	831,059	354,387	3,602,223	799,633	5,587,301
2007	858,131	367,297	3,721,551	812,950	5,759,929
2008	886,471	380,118	3,827,138	825,026	5,918,753
2009	916,937	392,836	3,919,034	835,987	6,064,794
2010	947,700	405,622	4,019,162	847,489	6,219,973
2011	978,110	418,082	4,124,370	859,179	6,379,742
2012	1,006,930	429,638	4,200,132	868,237	6,504,936

Utah Division - Wyoming (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	82,385	81,943	2,094,694	3,821	2,262,842
1992	84,065	83,957	2,158,265	3,821	2,330,108
1993	85,086	86,958	2,294,268	3,821	2,470,132
1994	86,576	90,617	2,423,796	3,821	2,604,810
1995	88,824	93,468	2,511,224	3,821	2,697,337
1996	91,866	96,582	2,616,131	3,821	2,808,400
1997	95,106	99,745	2,732,185	3,821	2,930,857
1998	98,375	103,379	2,852,012	3,821	3,057,586
1999	101,949	107,636	2,974,602	3,821	3,188,007
2000	105,765	112,402	3,097,049	3,821	3,319,038
2001	109,855	117,353	3,224,524	3,821	3,455,553
2002	114,323	122,178	3,354,487	3,821	3,594,809
2003	119,334	126,869	3,477,865	3,821	3,727,889
2004	124,580	131,541	3,594,753	3,821	3,854,695
2005	129,948	136,118	3,707,766	3,821	3,977,653
2006	135,738	141,355	3,822,006	3,821	4,102,920
2007	141,498	146,404	3,934,872	3,821	4,226,595
2008	147,473	151,232	4,038,805	3,821	4,341,331
2009	153,894	155,912	4,138,967	3,821	4,452,595
2010	160,498	160,682	4,236,605	3,821	4,561,606
2011	168,002	163,607	4,335,143	3,821	4,670,574
2012	175,423	165,783	4,433,251	3,821	4,778,277

Pacificorp - RAMPP 2 - High Sales Forecast

Utah Division - Utah (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	3,242,288	3,379,420	5,551,071	751,099	12,923,878
1992	3,414,488	3,562,206	5,992,283	772,757	13,741,734
1993	3,558,541	3,755,759	6,401,282	794,632	14,510,215
1994	3,699,269	3,954,383	6,805,369	816,291	15,275,313
1995	3,872,658	4,162,209	7,210,657	838,229	16,083,753
1996	4,031,203	4,378,767	7,630,149	860,303	16,900,423
1997	4,200,514	4,597,472	7,939,190	881,678	17,618,854
1998	4,376,040	4,825,583	8,273,451	903,334	18,378,409
1999	4,561,830	5,069,511	8,682,899	925,912	19,240,152
2000	4,745,212	5,324,743	9,107,701	948,818	20,126,474
2001	4,915,422	5,588,968	9,555,504	971,831	21,031,726
2002	5,108,214	5,858,883	9,984,559	994,673	21,946,328
2003	5,329,927	6,131,178	10,388,223	1,017,105	22,866,434
2004	5,549,831	6,406,666	10,777,693	1,039,184	23,773,375
2005	5,767,909	6,690,900	11,155,389	1,061,344	24,675,542
2006	6,014,890	6,984,072	11,615,320	1,083,810	25,698,092
2007	6,273,198	7,279,089	12,008,831	1,105,787	26,666,905
2008	6,548,930	7,574,631	12,363,165	1,127,275	27,614,002
2009	6,846,570	7,869,785	12,671,537	1,148,244	28,536,136
2010	7,154,540	8,169,927	13,008,638	1,169,170	29,502,276
2011	7,475,331	8,482,099	13,351,127	1,190,519	30,499,076
2012	7,803,319	8,803,706	13,639,433	1,211,966	31,458,424

Pacificorp (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	11,597,057	9,373,813	19,033,219	1,933,570	41,937,659
1992	12,037,456	9,814,631	20,112,149	1,984,651	43,948,887
1993	12,388,240	10,305,000	21,250,845	2,033,360	45,977,444
1994	12,775,139	10,809,825	22,299,024	2,080,005	47,963,993
1995	13,282,326	11,342,723	23,251,156	2,128,879	50,005,084
1996	13,843,864	11,893,214	24,344,114	2,181,385	52,262,576
1997	14,410,920	12,433,207	25,331,720	2,231,167	54,407,014
1998	14,946,593	12,977,399	26,394,108	2,280,117	56,598,217
1999	15,525,653	13,574,805	27,737,926	2,337,570	59,175,954
2000	16,088,001	14,198,587	29,067,105	2,393,754	61,747,447
2001	16,609,292	14,828,449	30,452,381	2,448,436	64,338,557
2002	17,175,386	15,452,836	31,788,373	2,501,001	66,917,597
2003	17,823,993	16,073,653	33,056,910	2,552,596	69,507,153
2004	18,458,445	16,677,757	34,270,670	2,602,558	72,009,430
2005	19,076,063	17,290,852	35,462,573	2,650,567	74,480,056
2006	19,752,176	17,909,103	36,779,540	2,702,395	77,143,214
2007	20,438,751	18,525,162	37,930,246	2,750,198	79,644,356
2008	21,170,113	19,140,160	38,963,078	2,796,281	82,069,633
2009	21,965,477	19,753,095	39,902,749	2,841,052	84,462,372
2010	22,780,142	20,371,577	40,896,600	2,886,383	86,934,701
2011	23,612,411	20,991,636	41,899,863	2,931,981	89,435,889
2012	24,426,525	21,596,170	42,706,558	2,973,259	91,702,512

Pacificorp - RAMPP 2 - Medium High Sales Forecast

Pacific Division - Oregon (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	4,752,002	3,320,772	3,779,303	330,252	12,182,329
1992	4,856,985	3,400,742	3,886,761	334,513	12,479,002
1993	4,923,571	3,503,713	3,986,475	338,289	12,752,047
1994	5,012,214	3,610,431	4,050,506	342,009	13,015,160
1995	5,150,747	3,726,561	4,130,578	346,797	13,354,683
1996	5,314,176	3,847,211	4,239,339	352,303	13,753,029
1997	5,465,112	3,957,983	4,329,135	357,191	14,109,421
1998	5,589,520	4,062,717	4,432,018	361,671	14,445,926
1999	5,731,329	4,186,231	4,603,716	367,342	14,888,618
2000	5,863,344	4,316,448	4,755,949	372,647	15,308,388
2001	5,978,109	4,442,021	4,932,830	377,826	15,730,786
2002	6,097,408	4,557,928	5,105,064	382,839	16,143,238
2003	6,243,424	4,668,716	5,270,796	388,049	16,570,986
2004	6,375,677	4,765,825	5,436,401	392,838	16,970,741
2005	6,496,679	4,862,479	5,605,304	397,439	17,361,901
2006	6,630,893	4,953,548	5,767,542	402,046	17,754,029
2007	6,761,276	5,041,114	5,893,589	406,151	18,102,130
2008	6,903,420	5,127,288	6,000,806	410,177	18,441,691
2009	7,065,145	5,212,640	6,094,037	414,287	18,786,109
2010	7,229,825	5,297,819	6,189,981	418,420	19,136,045
2011	7,400,750	5,382,143	6,279,222	422,525	19,484,640
2012	7,555,674	5,454,210	6,310,870	425,710	19,746,464

Pacific Division - Washington (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	1,373,976	999,265	802,317	155,079	3,330,636
1992	1,407,266	1,021,724	831,310	157,154	3,417,454
1993	1,431,212	1,045,935	860,678	159,038	3,496,863
1994	1,461,129	1,070,398	886,270	160,952	3,578,750
1995	1,500,304	1,096,168	914,792	163,144	3,674,408
1996	1,557,877	1,121,160	944,820	165,726	3,789,583
1997	1,615,048	1,145,000	972,486	168,179	3,900,713
1998	1,663,003	1,168,333	1,002,123	170,428	4,003,887
1999	1,714,555	1,195,614	1,044,767	173,082	4,128,018
2000	1,760,061	1,224,121	1,083,401	175,511	4,243,094
2001	1,805,304	1,252,810	1,118,196	177,825	4,354,136
2002	1,854,794	1,281,240	1,147,976	180,086	4,464,095
2003	1,910,431	1,308,973	1,175,842	182,385	4,577,631
2004	1,966,031	1,335,478	1,203,162	184,618	4,689,289
2005	2,016,901	1,361,099	1,229,852	186,700	4,794,551
2006	2,073,749	1,387,257	1,261,322	188,975	4,911,303
2007	2,128,753	1,412,686	1,286,347	191,049	5,018,835
2008	2,186,956	1,437,276	1,308,925	193,096	5,126,253
2009	2,250,134	1,460,617	1,329,793	195,157	5,235,701
2010	2,313,671	1,483,158	1,353,667	197,241	5,347,737
2011	2,377,552	1,504,802	1,377,824	199,296	5,459,474
2012	2,438,370	1,524,314	1,392,783	201,070	5,556,537

Pacificorp - RAMPP 2 - Medium High Sales Forecast

Pacific Division - Idaho (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	100,454	62,815	59,536	735	223,541
1992	103,040	65,110	58,758	735	227,642
1993	104,419	67,755	63,784	735	236,693
1994	106,133	70,652	70,018	735	247,538
1995	109,018	73,868	76,676	735	260,297
1996	112,986	77,391	82,795	735	273,907
1997	117,019	81,047	85,241	735	284,042
1998	120,868	84,897	88,843	735	295,342
1999	125,095	89,140	94,036	735	309,005
2000	129,079	93,666	99,798	735	323,277
2001	133,038	98,360	104,343	735	336,475
2002	137,416	103,119	108,122	735	349,391
2003	142,434	107,971	112,431	735	363,571
2004	147,352	112,798	114,840	735	375,724
2005	152,262	117,726	119,646	735	390,368
2006	157,396	122,674	122,407	735	403,212
2007	162,548	127,632	125,843	735	416,758
2008	167,981	132,632	130,115	735	431,462
2009	173,849	137,644	134,983	735	447,211
2010	179,756	142,710	139,729	735	462,929
2011	185,942	147,895	144,177	735	478,748
2012	191,875	152,981	147,373	735	492,963

Pacific Division - Montana (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	305,559	212,322	206,805	4,012	728,697
1992	314,376	220,199	199,237	4,012	737,824
1993	319,317	229,096	209,374	4,012	761,798
1994	323,133	238,030	216,231	4,012	781,406
1995	329,988	247,671	222,131	4,012	803,801
1996	339,179	257,334	225,574	4,012	826,099
1997	348,246	266,587	230,000	4,012	848,844
1998	356,596	275,895	239,305	4,012	875,807
1999	366,199	286,581	249,362	4,012	906,154
2000	374,927	297,755	265,770	4,012	942,464
2001	383,480	308,834	282,193	4,012	978,518
2002	392,731	319,742	298,316	4,012	1,014,802
2003	403,849	330,748	319,033	4,012	1,057,642
2004	414,079	341,168	324,061	4,012	1,083,318
2005	424,412	351,944	343,979	4,012	1,124,346
2006	435,269	362,648	357,812	4,012	1,159,741
2007	446,886	373,658	376,215	4,012	1,200,771
2008	459,588	384,989	385,060	4,012	1,233,648
2009	473,834	396,684	395,869	4,012	1,270,398
2010	488,236	408,628	415,719	4,012	1,316,594
2011	503,043	420,812	437,675	4,012	1,365,542
2012	516,993	432,463	449,002	4,012	1,402,470

Pacificorp - RAMPP 2 - Medium High Sales Forecast

Pacific Division - California (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	348,352	214,496	90,832	86,453	740,133
1992	358,101	220,690	91,858	88,390	759,039
1993	365,295	227,893	93,064	90,189	776,441
1994	371,637	235,204	92,666	91,752	791,259
1995	380,421	242,920	93,735	93,715	810,791
1996	391,631	250,755	95,032	95,927	833,345
1997	402,077	258,233	94,067	97,805	852,182
1998	410,591	265,213	93,101	99,443	868,348
1999	419,961	273,066	94,541	101,457	889,026
2000	428,175	281,191	95,160	103,304	907,829
2001	435,673	289,145	95,539	105,039	925,396
2002	444,143	296,816	95,835	106,813	943,607
2003	455,048	304,333	97,225	108,881	965,487
2004	464,597	311,278	96,705	110,591	983,171
2005	472,654	318,049	97,186	112,231	1,000,121
2006	482,065	324,577	96,228	113,833	1,016,702
2007	491,540	330,902	95,990	115,476	1,033,908
2008	501,793	337,070	96,388	117,222	1,052,473
2009	513,363	343,159	97,575	119,134	1,073,231
2010	524,715	349,130	98,903	121,019	1,093,768
2011	535,877	354,964	100,167	122,860	1,113,869
2012	545,982	360,145	100,075	124,424	1,130,626

Pacific Division - Wyoming (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	702,700	829,698	4,518,616	22,796	6,073,810
1992	715,495	854,011	4,632,549	22,869	6,224,924
1993	721,365	880,572	4,878,590	23,000	6,503,528
1994	730,176	908,857	5,104,992	23,121	6,767,146
1995	745,631	939,625	5,254,657	23,208	6,963,120
1996	768,150	972,531	5,408,174	23,299	7,172,154
1997	792,493	1,007,047	5,575,055	23,394	7,397,990
1998	815,784	1,043,853	5,752,019	23,493	7,635,149
1999	840,543	1,083,646	5,969,799	23,607	7,917,595
2000	865,671	1,125,798	6,182,508	23,717	8,197,694
2001	892,800	1,169,934	6,400,506	23,828	8,487,068
2002	923,971	1,215,764	6,612,249	23,936	8,775,919
2003	960,414	1,262,998	6,804,960	24,036	9,052,409
2004	998,505	1,311,212	6,984,700	24,131	9,318,548
2005	1,038,399	1,360,861	7,150,109	24,220	9,573,588
2006	1,078,996	1,412,593	7,340,479	24,316	9,856,384
2007	1,120,895	1,465,721	7,509,050	24,404	10,120,071
2008	1,165,816	1,520,180	7,653,451	24,484	10,363,932
2009	1,214,517	1,575,595	7,781,027	24,559	10,595,698
2010	1,264,136	1,632,388	7,908,862	24,633	10,830,019
2011	1,317,339	1,692,129	8,042,390	24,710	11,076,567
2012	1,373,178	1,754,163	8,153,370	24,780	11,305,492

Pacificorp - RAMPP 2 - Medium High Sales Forecast

Utah Division - Idaho (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	537,250	183,029	1,621,455	556,445	2,898,180
1992	544,511	188,278	1,720,378	569,767	3,022,936
1993	547,390	194,262	1,818,764	582,303	3,142,720
1994	552,784	200,534	1,902,871	593,272	3,249,461
1995	563,200	207,210	1,983,817	604,293	3,358,521
1996	578,157	214,189	2,077,623	617,049	3,487,018
1997	593,526	221,005	2,163,934	628,766	3,607,232
1998	607,031	227,694	2,249,934	640,023	3,724,683
1999	621,194	235,180	2,388,678	656,680	3,901,733
2000	634,164	242,981	2,523,284	672,422	4,072,851
2001	645,593	250,916	2,653,812	687,260	4,237,581
2002	658,940	258,760	2,768,275	700,413	4,386,389
2003	674,723	266,544	2,871,795	712,511	4,525,572
2004	690,264	274,088	2,975,164	724,344	4,663,860
2005	704,565	281,582	3,063,136	734,463	4,783,746
2006	721,304	289,221	3,191,018	748,272	4,949,815
2007	737,562	296,631	3,289,889	759,198	5,083,280
2008	754,493	303,830	3,375,716	768,869	5,202,908
2009	772,783	310,791	3,448,542	777,396	5,309,511
2010	790,852	317,649	3,528,795	786,433	5,423,730
2011	809,071	324,463	3,612,891	795,699	5,542,124
2012	826,308	330,772	3,668,628	802,371	5,628,078

Utah Division - Wyoming (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	82,213	79,714	2,065,292	3,821	2,231,040
1992	82,713	78,706	2,098,588	3,821	2,263,828
1993	82,524	78,476	2,204,083	3,821	2,368,904
1994	82,798	78,943	2,303,018	3,821	2,468,580
1995	83,806	78,874	2,359,756	3,821	2,526,257
1996	85,564	79,240	2,414,593	3,821	2,583,218
1997	87,509	79,864	2,480,690	3,821	2,651,884
1998	89,476	81,010	2,550,425	3,821	2,724,733
1999	91,706	82,750	2,622,679	3,821	2,800,957
2000	94,149	84,949	2,694,681	3,821	2,877,601
2001	96,830	87,368	2,771,773	3,821	2,959,792
2002	99,845	89,744	2,851,534	3,821	3,044,944
2003	103,354	92,117	2,924,883	3,821	3,124,175
2004	107,062	94,527	2,990,830	3,821	3,196,241
2005	110,860	96,930	3,052,556	3,821	3,264,167
2006	114,940	99,813	3,115,512	3,821	3,334,085
2007	118,986	102,616	3,176,271	3,821	3,401,694
2008	123,216	105,306	3,228,044	3,821	3,460,386
2009	127,832	107,965	3,276,221	3,821	3,515,839
2010	132,595	110,707	3,321,830	3,821	3,568,954
2011	138,150	111,665	3,368,367	3,821	3,622,003
2012	143,652	112,157	3,414,582	3,821	3,674,212

Pacificorp - RAMPP 2 - Medium High Sales Forecast

Utah Division - Utah (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	3,217,607	3,326,153	5,368,039	745,324	12,657,124
1992	3,347,798	3,448,857	5,708,112	761,051	13,265,818
1993	3,447,733	3,579,066	6,021,983	777,029	13,825,813
1994	3,542,140	3,712,637	6,341,429	792,971	14,389,177
1995	3,665,649	3,853,214	6,657,334	809,288	14,985,485
1996	3,774,560	4,000,356	6,980,618	825,832	15,581,366
1997	3,892,140	4,149,128	7,206,883	841,911	16,090,062
1998	4,013,731	4,304,848	7,461,722	858,347	16,638,648
1999	4,143,050	4,472,136	7,782,857	875,645	17,273,688
2000	4,268,292	4,647,315	8,113,801	893,269	17,922,677
2001	4,382,150	4,828,850	8,466,565	911,069	18,588,634
2002	4,515,698	5,014,474	8,797,847	928,803	19,256,822
2003	4,674,803	5,201,608	9,102,006	946,268	19,924,684
2004	4,830,914	5,390,771	9,388,807	963,486	20,573,978
2005	4,983,887	5,585,808	9,657,911	980,785	21,208,391
2006	5,161,456	5,786,912	9,998,485	998,408	21,945,261
2007	5,347,602	5,988,840	10,273,871	1,015,631	22,625,944
2008	5,547,682	6,190,597	10,508,889	1,032,463	23,279,631
2009	5,765,554	6,391,613	10,699,409	1,048,882	23,905,458
2010	5,990,711	6,595,652	10,910,735	1,065,286	24,562,384
2011	6,232,479	6,811,528	11,123,938	1,082,311	25,250,257
2012	6,479,124	7,032,128	11,262,887	1,099,266	25,873,405

Pacificorp (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	11,420,113	9,228,265	18,512,196	1,904,916	41,065,490
1992	11,730,285	9,498,317	19,227,550	1,942,313	42,398,466
1993	11,942,827	9,806,769	20,136,796	1,978,415	43,864,807
1994	12,182,145	10,125,687	20,968,000	2,012,643	45,288,476
1995	12,528,763	10,466,111	21,693,476	2,049,012	46,737,362
1996	12,922,281	10,820,166	22,468,567	2,088,702	48,299,717
1997	13,313,171	11,165,892	23,137,492	2,125,814	49,742,369
1998	13,666,600	11,514,461	23,869,489	2,161,972	51,212,522
1999	14,053,631	11,904,344	24,850,436	2,206,382	53,014,793
2000	14,417,862	12,314,224	25,814,352	2,249,436	54,795,875
2001	14,752,977	12,728,239	26,825,756	2,291,414	56,598,386
2002	15,124,944	13,137,587	27,785,219	2,331,457	58,379,207
2003	15,568,481	13,544,008	28,678,970	2,370,698	60,162,157
2004	15,994,482	13,937,144	29,514,669	2,408,575	61,854,871
2005	16,400,618	14,336,477	30,319,678	2,444,405	63,501,180
2006	16,856,068	14,739,243	31,250,805	2,484,416	65,330,532
2007	17,316,049	15,139,801	32,027,065	2,520,476	67,003,391
2008	17,810,945	15,539,168	32,687,392	2,554,879	68,592,384
2009	18,357,011	15,936,708	33,257,456	2,587,981	70,139,156
2010	18,914,498	16,337,842	33,868,220	2,621,600	71,742,160
2011	19,500,203	16,750,401	34,486,652	2,655,968	73,393,225
2012	20,071,157	17,153,332	34,899,571	2,686,188	74,810,248

Pacificorp - RAMPP 2 - Medium Low Sales Forecast

Pacific Division - Oregon (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	4,693,119	3,269,219	3,633,071	326,839	11,922,247
1992	4,702,722	3,266,723	3,644,443	327,282	11,941,170
1993	4,797,910	3,341,469	3,907,535	333,266	12,380,180
1994	4,898,103	3,423,748	3,982,592	337,081	12,641,523
1995	4,969,898	3,474,374	3,902,021	338,137	12,684,430
1996	5,014,387	3,502,608	3,832,907	338,581	12,688,482
1997	5,059,020	3,525,528	3,792,092	339,285	12,715,924
1998	5,096,407	3,554,108	3,790,893	340,404	12,781,812
1999	5,131,721	3,591,051	3,805,768	341,778	12,870,318
2000	5,162,553	3,634,596	3,817,893	343,125	12,958,168
2001	5,188,477	3,676,613	3,860,740	344,722	13,070,551
2002	5,219,468	3,712,450	3,910,605	346,392	13,188,914
2003	5,266,454	3,740,967	3,931,652	347,884	13,286,957
2004	5,326,485	3,773,344	3,996,852	350,129	13,446,810
2005	5,392,493	3,816,739	4,086,940	352,875	13,649,048
2006	5,469,689	3,859,115	4,173,370	355,722	13,857,896
2007	5,563,172	3,907,890	4,252,910	358,799	14,082,772
2008	5,665,332	3,957,307	4,312,894	361,775	14,297,308
2009	5,781,469	4,005,725	4,357,505	364,759	14,509,458
2010	5,892,274	4,050,064	4,391,766	367,475	14,701,580
2011	5,988,459	4,082,301	4,384,475	369,354	14,824,589
2012	6,085,886	4,111,969	4,384,241	371,285	14,953,382

Pacific Division - Washington (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	1,360,732	987,776	777,201	153,909	3,279,618
1992	1,375,428	997,128	795,543	155,001	3,323,100
1993	1,400,849	1,013,996	852,003	157,402	3,424,250
1994	1,427,459	1,031,106	876,572	159,070	3,494,207
1995	1,450,396	1,044,242	877,905	160,016	3,532,559
1996	1,486,370	1,054,079	880,415	161,197	3,582,061
1997	1,522,321	1,062,810	886,034	162,409	3,633,574
1998	1,551,977	1,071,894	898,724	163,635	3,686,230
1999	1,577,788	1,081,928	913,713	164,838	3,738,266
2000	1,599,100	1,092,584	927,242	165,916	3,784,841
2001	1,618,976	1,103,002	937,715	166,883	3,826,575
2002	1,642,190	1,112,478	947,001	167,868	3,869,536
2003	1,670,522	1,121,119	952,421	168,855	3,912,917
2004	1,701,094	1,130,285	961,935	169,981	3,963,295
2005	1,731,781	1,140,997	977,939	171,272	4,021,988
2006	1,762,237	1,151,033	991,194	172,474	4,076,938
2007	1,801,957	1,163,581	1,005,331	173,933	4,144,803
2008	1,841,660	1,175,824	1,016,515	175,312	4,209,312
2009	1,885,392	1,187,337	1,024,726	176,685	4,274,139
2010	1,926,761	1,196,976	1,034,545	177,991	4,336,273
2011	1,964,774	1,204,424	1,039,303	179,072	4,387,573
2012	2,004,371	1,212,419	1,044,337	180,192	4,441,320

Pacificorp - RAMPP 2 - Medium Low Sales Forecast

Pacific Division - Idaho (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	99,372	62,010	54,505	735	216,622
1992	100,278	63,091	55,268	735	219,372
1993	102,678	65,132	58,621	735	227,166
1994	104,625	67,388	61,900	735	234,647
1995	106,229	69,532	60,147	735	236,642
1996	108,440	71,625	57,701	735	238,501
1997	111,030	73,797	57,142	735	242,704
1998	113,565	76,126	58,281	735	248,707
1999	116,017	78,628	59,984	735	255,364
2000	118,239	81,294	62,114	735	262,382
2001	120,381	84,042	63,483	735	268,641
2002	122,868	86,804	63,866	735	274,272
2003	125,740	89,568	63,555	735	279,598
2004	128,962	92,446	64,439	735	286,582
2005	132,331	95,538	66,632	735	295,236
2006	136,049	98,761	67,840	735	303,385
2007	139,971	102,145	69,306	735	312,157
2008	144,146	105,635	70,823	735	321,339
2009	148,702	109,217	72,612	735	331,266
2010	153,237	112,865	73,904	735	340,741
2011	157,621	116,462	73,037	735	347,855
2012	162,093	120,068	72,973	735	355,869

Pacific Division - Montana (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	299,746	208,365	182,413	4,012	694,536
1992	302,370	211,629	192,884	4,012	710,895
1993	309,335	218,947	204,049	4,012	736,343
1994	313,273	226,143	211,354	4,012	754,781
1995	314,943	231,448	215,438	4,012	765,840
1996	317,390	235,649	216,362	4,012	773,413
1997	321,342	240,053	215,814	4,012	781,220
1998	325,869	245,185	222,029	4,012	797,095
1999	330,412	250,966	232,009	4,012	817,399
2000	334,499	257,231	241,530	4,012	837,271
2001	338,565	263,490	247,746	4,012	853,812
2002	342,883	269,319	249,193	4,012	865,407
2003	348,080	274,716	247,131	4,012	873,938
2004	354,327	280,656	252,104	4,012	891,099
2005	361,540	287,575	265,427	4,012	918,554
2006	369,242	294,581	273,460	4,012	941,295
2007	377,827	301,987	282,691	4,012	966,517
2008	387,061	309,507	289,119	4,012	989,698
2009	397,401	317,187	295,456	4,012	1,014,055
2010	407,094	324,508	300,659	4,012	1,036,272
2011	415,584	331,015	298,018	4,012	1,048,629
2012	424,958	338,046	299,412	4,012	1,066,428

Pacificorp - RAMPP 2 - Medium Low Sales Forecast

Pacific Division - California (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	344,175	210,973	83,316	84,974	723,439
1992	347,567	212,311	82,831	85,667	728,376
1993	354,837	216,498	85,879	87,372	744,587
1994	360,568	220,983	87,651	88,828	758,030
1995	364,434	224,186	84,732	89,518	762,871
1996	368,528	226,279	81,318	90,066	766,191
1997	372,582	228,062	79,950	90,768	771,362
1998	376,046	229,912	80,664	91,614	778,237
1999	378,989	231,936	82,590	92,541	786,056
2000	381,095	234,093	85,074	93,452	793,714
2001	382,592	236,084	86,353	94,172	799,200
2002	384,741	237,668	85,774	94,735	802,919
2003	388,453	238,797	84,053	95,289	806,592
2004	392,399	240,068	83,905	96,025	812,397
2005	396,072	241,791	85,335	96,926	820,123
2006	401,320	243,523	85,324	97,837	828,004
2007	407,163	245,392	85,812	98,861	837,228
2008	413,748	247,253	86,349	99,952	847,303
2009	421,524	249,132	87,320	101,190	859,166
2010	428,852	250,782	87,578	102,296	869,508
2011	435,020	251,767	85,376	103,004	875,167
2012	441,270	252,727	84,476	103,829	882,302

Pacific Division - Wyoming (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	698,279	819,008	4,358,868	22,711	5,898,866
1992	705,178	829,861	4,401,658	22,742	5,959,440
1993	707,864	844,753	4,626,064	22,860	6,201,542
1994	711,660	860,392	4,791,147	22,948	6,386,147
1995	718,457	875,406	4,856,194	22,989	6,473,046
1996	730,668	890,525	4,912,008	23,028	6,556,228
1997	744,936	906,654	4,989,213	23,077	6,663,880
1998	757,597	924,197	5,071,268	23,128	6,776,190
1999	770,300	942,998	5,155,940	23,180	6,892,418
2000	782,236	962,639	5,232,719	23,228	7,000,821
2001	795,028	982,870	5,310,753	23,277	7,111,927
2002	810,618	1,003,608	5,390,316	23,327	7,227,869
2003	829,792	1,024,307	5,451,118	23,370	7,328,588
2004	849,901	1,045,168	5,508,167	23,411	7,426,647
2005	870,948	1,066,601	5,570,175	23,455	7,531,178
2006	890,242	1,088,176	5,634,441	23,498	7,636,356
2007	909,661	1,109,848	5,692,996	23,539	7,736,043
2008	929,994	1,131,162	5,734,992	23,573	7,819,721
2009	951,842	1,151,771	5,763,953	23,602	7,891,168
2010	972,621	1,171,804	5,784,143	23,627	7,952,195
2011	993,868	1,191,504	5,802,785	23,651	8,011,809
2012	1,016,142	1,211,254	5,817,594	23,674	8,068,664

Pacificorp - RAMPP 2 - Medium Low Sales Forecast

Utah Division - Idaho (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	530,351	180,460	1,581,653	550,590	2,843,055
1992	530,219	182,145	1,606,950	553,916	2,873,230
1993	532,153	186,307	1,755,825	572,483	3,046,767
1994	535,115	190,649	1,850,618	584,370	3,160,752
1995	538,182	193,934	1,876,475	588,118	3,196,709
1996	543,216	196,584	1,901,469	591,888	3,233,156
1997	548,840	199,083	1,927,029	595,741	3,270,693
1998	553,220	201,666	1,954,424	599,645	3,308,956
1999	556,750	204,480	1,983,013	603,586	3,347,829
2000	559,039	207,465	2,009,040	607,104	3,382,648
2001	559,926	210,452	2,026,628	609,530	3,406,537
2002	562,564	213,392	2,040,412	611,717	3,428,084
2003	567,151	216,218	2,042,412	612,822	3,438,603
2004	572,531	219,196	2,049,073	614,528	3,455,328
2005	577,858	222,553	2,069,793	617,776	3,487,980
2006	586,073	226,323	2,094,370	621,773	3,528,540
2007	594,116	230,041	2,116,559	625,466	3,566,181
2008	602,731	233,637	2,133,488	628,626	3,598,482
2009	612,379	237,080	2,141,855	630,962	3,622,276
2010	621,549	240,384	2,149,963	633,196	3,645,093
2011	629,667	243,295	2,154,962	634,944	3,662,868
2012	637,759	246,094	2,154,665	636,122	3,674,640

Utah Division - Wyoming (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	81,330	78,783	2,006,004	3,821	2,169,937
1992	80,492	75,665	2,017,525	3,821	2,177,503
1993	80,451	75,691	2,120,905	3,821	2,280,868
1994	80,320	75,709	2,197,609	3,821	2,357,459
1995	80,154	74,214	2,224,180	3,821	2,382,370
1996	80,690	72,836	2,246,875	3,821	2,404,222
1997	81,581	71,850	2,279,103	3,821	2,436,356
1998	82,512	71,381	2,314,114	3,821	2,471,828
1999	83,681	71,397	2,350,528	3,821	2,509,426
2000	85,022	71,812	2,385,099	3,821	2,545,754
2001	86,588	72,431	2,422,883	3,821	2,585,723
2002	88,608	73,221	2,462,170	3,821	2,627,820
2003	91,207	74,190	2,495,681	3,821	2,664,898
2004	94,029	75,289	2,525,688	3,821	2,698,826
2005	97,193	76,645	2,552,763	3,821	2,730,421
2006	100,216	78,099	2,579,996	3,821	2,762,132
2007	103,466	79,709	2,605,292	3,821	2,792,288
2008	106,915	81,290	2,623,831	3,821	2,815,856
2009	110,604	82,797	2,638,524	3,821	2,835,746
2010	114,459	84,389	2,649,206	3,821	2,851,876
2011	118,840	84,466	2,660,455	3,821	2,867,582
2012	123,348	84,335	2,671,739	3,821	2,883,242

Pacificorp - RAMPP 2 - Medium Low Sales Forecast

Utah Division - Utah (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	3,148,927	3,256,949	5,184,624	737,401	12,327,901
1992	3,210,359	3,300,588	5,266,989	744,142	12,522,078
1993	3,287,303	3,378,313	5,600,585	755,328	13,021,529
1994	3,335,117	3,451,143	5,817,886	765,410	13,369,557
1995	3,385,824	3,510,251	5,891,871	773,475	13,561,420
1996	3,420,951	3,566,812	5,982,415	781,134	13,751,312
1997	3,468,432	3,624,231	6,043,333	788,717	13,924,714
1998	3,517,546	3,685,315	6,127,742	796,634	14,127,238
1999	3,567,432	3,750,810	6,221,760	804,920	14,344,922
2000	3,611,729	3,819,201	6,315,561	813,367	14,559,858
2001	3,661,586	3,889,710	6,420,794	821,955	14,794,044
2002	3,729,604	3,963,131	6,530,092	830,770	15,053,597
2003	3,822,715	4,038,062	6,619,662	839,631	15,320,069
2004	3,918,426	4,115,969	6,724,271	848,703	15,607,369
2005	4,014,861	4,199,096	6,859,412	858,230	15,931,599
2006	4,134,899	4,292,726	7,015,164	868,734	16,311,523
2007	4,263,112	4,380,375	7,155,986	878,520	16,677,994
2008	4,399,728	4,464,423	7,268,978	887,808	17,020,936
2009	4,549,028	4,545,355	7,346,085	896,647	17,337,114
2010	4,699,435	4,625,859	7,416,981	905,345	17,647,619
2011	4,858,679	4,709,025	7,466,319	914,160	17,948,183
2012	5,030,409	4,794,982	7,502,734	923,108	18,251,233

Pacificorp (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	11,256,031	9,073,543	17,861,655	1,884,993	40,076,221
1992	11,354,613	9,139,141	18,064,092	1,897,317	40,455,163
1993	11,573,380	9,341,107	19,211,467	1,937,277	42,063,231
1994	11,766,240	9,547,259	19,877,328	1,966,275	43,157,102
1995	11,928,517	9,697,586	19,988,963	1,980,820	43,595,887
1996	12,070,640	9,816,996	20,111,469	1,994,461	43,993,566
1997	12,230,086	9,932,068	20,269,710	2,008,564	44,440,428
1998	12,374,740	10,059,787	20,518,140	2,023,628	44,976,294
1999	12,513,089	10,204,194	20,805,305	2,039,410	45,561,999
2000	12,633,512	10,360,914	21,076,271	2,054,760	46,125,456
2001	12,752,118	10,518,692	21,377,094	2,069,106	46,717,010
2002	12,903,544	10,672,070	21,679,428	2,083,376	47,338,418
2003	13,110,114	10,817,944	21,887,685	2,096,418	47,912,161
2004	13,338,152	10,972,420	22,166,434	2,111,346	48,588,352
2005	13,575,076	11,147,535	22,534,415	2,129,101	49,386,127
2006	13,849,966	11,332,337	22,915,160	2,148,605	50,246,068
2007	14,160,447	11,520,967	23,266,883	2,167,685	51,115,982
2008	14,491,315	11,706,038	23,536,987	2,185,613	51,919,954
2009	14,858,341	11,885,600	23,728,036	2,202,411	52,674,388
2010	15,216,284	12,057,631	23,888,745	2,218,498	53,381,158
2011	15,562,513	12,214,261	23,964,730	2,232,752	53,974,256
2012	15,926,237	12,371,894	24,032,173	2,246,776	54,577,080

Pacificorp - RAMPP 2 - Low Sales Forecast

Pacific Division - Oregon (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	4,646,544	3,253,191	3,595,537	325,397	11,820,669
1992	4,600,959	3,226,278	3,569,575	324,127	11,720,940
1993	4,632,568	3,264,352	3,687,552	326,825	11,911,297
1994	4,664,003	3,306,385	3,681,190	328,039	11,979,616
1995	4,665,145	3,319,231	3,591,792	327,330	11,903,498
1996	4,662,526	3,311,944	3,506,959	326,332	11,807,761
1997	4,659,189	3,299,807	3,445,340	325,531	11,729,867
1998	4,648,292	3,292,211	3,417,957	325,076	11,683,536
1999	4,634,713	3,291,314	3,403,276	324,817	11,654,120
2000	4,616,564	3,295,640	3,384,515	324,499	11,621,218
2001	4,593,921	3,298,519	3,396,972	324,463	11,613,875
2002	4,575,964	3,296,359	3,415,835	324,513	11,612,672
2003	4,573,287	3,288,503	3,406,619	324,399	11,592,808
2004	4,581,402	3,283,702	3,412,022	324,688	11,601,813
2005	4,593,081	3,287,164	3,439,763	325,422	11,645,430
2006	4,614,933	3,289,112	3,453,075	326,130	11,683,251
2007	4,650,097	3,295,903	3,473,247	327,210	11,746,457
2008	4,691,727	3,303,015	3,487,449	328,325	11,810,516
2009	4,744,315	3,309,364	3,497,705	329,562	11,880,946
2010	4,792,155	3,312,791	3,505,402	330,643	11,940,992
2011	4,832,284	3,309,190	3,482,983	331,130	11,955,586
2012	4,874,078	3,304,320	3,470,751	331,745	11,980,894

Pacific Division - Washington (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	1,353,187	985,433	771,005	153,536	3,263,161
1992	1,357,849	990,509	781,382	154,108	3,283,847
1993	1,371,002	1,001,201	804,623	155,316	3,332,143
1994	1,383,830	1,011,361	822,588	156,371	3,374,151
1995	1,391,982	1,017,481	820,938	156,761	3,387,163
1996	1,411,569	1,020,295	818,025	157,301	3,407,191
1997	1,429,945	1,021,737	817,602	157,833	3,427,117
1998	1,441,278	1,023,088	823,390	158,341	3,446,097
1999	1,448,123	1,024,901	830,591	158,787	3,462,402
2000	1,450,076	1,026,919	835,395	159,071	3,471,461
2001	1,450,090	1,028,406	837,002	159,225	3,474,722
2002	1,452,569	1,028,840	837,303	159,379	3,478,091
2003	1,459,229	1,028,344	833,954	159,523	3,481,050
2004	1,467,175	1,028,022	834,166	159,779	3,489,142
2005	1,474,457	1,028,690	840,011	160,169	3,503,326
2006	1,480,565	1,028,400	843,244	160,448	3,512,656
2007	1,494,889	1,030,186	847,116	160,976	3,533,166
2008	1,508,257	1,031,557	848,323	161,411	3,549,548
2009	1,524,368	1,032,213	846,935	161,830	3,565,347
2010	1,537,954	1,031,319	846,864	162,186	3,578,323
2011	1,549,344	1,028,907	842,413	162,359	3,583,023
2012	1,561,659	1,026,916	838,213	162,566	3,589,355

Pacificorp - RAMPP 2 - Low Sales Forecast

Pacific Division - Idaho (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	98,902	61,207	54,104	735	214,949
1992	99,110	61,279	54,453	735	215,576
1993	100,567	62,054	55,327	735	218,683
1994	101,424	62,884	56,030	735	221,073
1995	101,800	63,462	56,281	735	222,279
1996	102,574	63,862	55,147	735	222,318
1997	103,551	64,200	54,327	735	222,813
1998	104,338	64,538	55,063	735	224,674
1999	104,920	64,906	56,321	735	226,882
2000	105,196	65,305	57,970	735	229,205
2001	105,300	65,651	58,862	735	230,548
2002	105,580	65,921	58,778	735	231,014
2003	106,102	66,082	58,008	735	230,927
2004	106,823	66,250	58,360	735	232,167
2005	107,561	66,493	59,928	735	234,716
2006	108,488	66,716	60,529	735	236,467
2007	109,474	66,974	61,347	735	238,530
2008	110,560	67,217	62,194	735	240,707
2009	111,860	67,456	63,282	735	243,333
2010	113,045	67,661	63,880	735	245,322
2011	114,195	67,845	62,450	735	245,225
2012	115,364	67,962	61,743	735	245,803

Pacific Division - Montana (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	298,411	205,543	191,407	4,012	699,372
1992	299,416	205,454	188,625	4,012	697,507
1993	304,539	208,840	187,716	4,012	705,107
1994	306,530	211,928	187,034	4,012	709,503
1995	306,177	213,186	189,435	4,012	712,809
1996	306,475	213,356	188,680	4,012	712,523
1997	308,116	213,549	186,205	4,012	711,882
1998	310,203	214,218	190,118	4,012	718,551
1999	312,206	215,282	197,457	4,012	728,956
2000	313,685	216,604	204,168	4,012	738,469
2001	315,063	217,781	207,474	4,012	744,330
2002	316,599	218,505	206,138	4,012	745,253
2003	318,898	218,771	201,376	4,012	743,056
2004	322,065	219,339	203,001	4,012	748,416
2005	326,008	220,511	212,098	4,012	762,629
2006	330,284	221,605	216,100	4,012	772,000
2007	335,213	222,838	220,962	4,012	783,025
2008	340,549	223,987	223,068	4,012	791,615
2009	346,665	225,070	224,891	4,012	800,638
2010	352,026	225,744	225,496	4,012	807,277
2011	357,083	226,067	218,981	4,012	806,143
2012	362,916	226,650	215,831	4,012	809,409

Pacificorp - RAMPP 2 - Low Sales Forecast

Pacific Division - California (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	341,963	208,482	81,875	84,366	716,686
1992	342,528	206,910	79,919	84,345	713,702
1993	346,400	207,526	80,938	85,165	720,029
1994	348,493	208,183	80,743	85,698	723,117
1995	348,676	207,643	76,263	85,503	718,085
1996	348,974	206,072	71,442	85,177	711,664
1997	349,074	204,150	68,514	84,972	706,711
1998	348,455	202,171	67,410	84,866	702,902
1999	347,221	200,233	67,312	84,802	699,568
2000	345,113	198,316	67,634	84,693	695,755
2001	342,700	196,176	66,974	84,436	690,285
2002	340,911	193,675	64,890	84,060	683,536
2003	340,567	190,796	61,983	83,703	677,049
2004	340,287	187,951	60,238	83,466	671,942
2005	339,579	185,308	59,577	83,314	667,777
2006	340,357	182,619	57,925	83,203	664,104
2007	341,531	179,941	56,576	83,160	661,209
2008	343,223	177,143	55,219	83,155	658,741
2009	345,751	174,248	54,063	83,238	657,300
2010	347,772	171,094	52,433	83,198	654,498
2011	349,075	167,575	49,451	82,915	649,016
2012	350,481	164,030	47,164	82,705	644,380

Pacific Division - Wyoming (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	688,419	798,495	4,313,122	22,674	5,822,710
1992	685,997	789,606	4,339,717	22,683	5,838,003
1993	680,114	785,141	4,444,353	22,730	5,932,338
1994	676,028	782,148	4,525,344	22,767	6,006,286
1995	675,398	779,355	4,545,654	22,776	6,023,183
1996	680,221	776,692	4,558,159	22,784	6,037,856
1997	687,065	774,583	4,587,965	22,802	6,072,415
1998	692,370	773,179	4,622,954	22,821	6,111,325
1999	697,625	772,298	4,657,557	22,840	6,150,321
2000	702,073	771,599	4,682,842	22,855	6,179,369
2001	707,200	770,939	4,706,269	22,869	6,207,278
2002	714,717	770,245	4,728,547	22,884	6,236,392
2003	725,343	769,162	4,729,444	22,889	6,246,837
2004	736,582	767,867	4,726,598	22,893	6,253,941
2005	748,407	766,650	4,727,404	22,899	6,265,360
2006	757,842	765,183	4,729,420	22,905	6,275,349
2007	767,055	763,440	4,725,556	22,907	6,278,957
2008	776,757	761,135	4,706,477	22,903	6,267,272
2009	787,475	758,111	4,675,452	22,892	6,243,931
2010	796,863	754,394	4,635,901	22,877	6,210,035
2011	808,329	751,217	4,613,470	22,871	6,195,887
2012	821,184	748,506	4,588,812	22,865	6,181,366

Pacificorp - RAMPP 2 - Low Sales Forecast

Utah Division - Idaho (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	526,795	179,622	1,578,249	549,661	2,834,327
1992	522,503	180,190	1,600,076	551,937	2,854,706
1993	519,782	182,901	1,738,641	568,601	3,009,926
1994	517,724	185,623	1,828,866	579,258	3,111,471
1995	515,477	187,234	1,850,862	581,792	3,135,366
1996	514,815	188,148	1,871,942	584,305	3,159,210
1997	514,392	188,820	1,893,532	586,858	3,183,602
1998	512,492	189,493	1,916,813	589,423	3,208,221
1999	509,539	190,252	1,941,144	591,987	3,232,922
2000	505,222	191,085	1,962,855	594,102	3,253,264
2001	500,722	191,832	1,976,189	595,247	3,263,989
2002	497,660	192,445	1,985,721	596,110	3,271,937
2003	496,247	192,895	1,983,637	595,848	3,268,627
2004	495,311	193,390	1,986,068	596,142	3,270,910
2005	494,096	194,090	2,002,117	597,938	3,288,242
2006	495,377	195,085	2,021,826	600,439	3,312,726
2007	496,258	195,933	2,039,096	602,599	3,333,885
2008	497,366	196,558	2,051,219	604,187	3,349,331
2009	499,051	196,957	2,055,031	604,897	3,355,936
2010	500,069	197,156	2,058,509	605,472	3,361,206
2011	500,474	197,114	2,058,938	605,621	3,362,146
2012	501,019	197,099	2,054,216	605,224	3,357,559

Utah Division - Wyoming (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	79,924	77,754	1,947,702	3,821	2,109,201
1992	77,965	73,323	1,948,773	3,821	2,103,881
1993	76,765	71,398	1,944,442	3,821	2,096,426
1994	75,500	69,601	1,942,502	3,821	2,091,424
1995	74,244	66,652	1,940,190	3,821	2,084,907
1996	73,685	63,955	1,934,372	3,821	2,075,834
1997	73,490	61,724	1,938,163	3,821	2,077,198
1998	73,360	60,030	1,944,664	3,821	2,081,874
1999	73,471	58,817	1,952,447	3,821	2,088,555
2000	73,766	57,989	1,958,351	3,821	2,093,928
2001	74,291	57,257	1,967,491	3,821	2,102,860
2002	75,240	56,667	1,978,111	3,821	2,113,838
2003	76,726	56,262	1,982,986	3,821	2,119,795
2004	78,409	55,952	1,984,224	3,821	2,122,406
2005	80,393	55,866	1,982,214	3,821	2,122,293
2006	82,171	55,863	1,980,175	3,821	2,122,030
2007	84,153	55,984	1,976,043	3,821	2,120,002
2008	86,308	56,135	1,965,198	3,821	2,111,462
2009	88,677	56,224	1,950,586	3,821	2,099,308
2010	91,208	56,421	1,931,833	3,821	2,083,282
2011	94,712	55,906	1,913,892	3,821	2,068,331
2012	98,341	55,305	1,896,133	3,821	2,053,600

Pacificorp - RAMPP 2 - Low Sales Forecast

Utah Division - Utah (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	3,088,951	3,195,661	5,146,136	730,956	12,161,704
1992	3,087,544	3,170,197	5,179,685	730,461	12,167,887
1993	3,098,405	3,163,794	5,400,974	732,895	12,396,068
1994	3,080,279	3,153,486	5,538,975	734,533	12,507,273
1995	3,058,255	3,135,108	5,573,413	734,826	12,501,603
1996	3,054,738	3,115,463	5,620,307	734,991	12,525,499
1997	3,061,927	3,096,445	5,666,089	735,208	12,559,669
1998	3,069,928	3,079,456	5,712,659	735,636	12,597,679
1999	3,078,021	3,064,778	5,762,047	736,322	12,641,168
2000	3,080,870	3,051,538	5,802,639	737,114	12,672,161
2001	3,088,425	3,039,353	5,842,018	738,017	12,707,813
2002	3,111,522	3,028,676	5,881,660	739,122	12,760,980
2003	3,156,516	3,018,677	5,898,839	740,284	12,814,317
2004	3,202,687	3,010,082	5,925,943	741,624	12,880,335
2005	3,248,172	3,003,869	5,979,944	743,308	12,975,294
2006	3,312,805	3,002,687	6,045,340	745,685	13,106,516
2007	3,382,593	2,998,128	6,092,445	747,586	13,220,752
2008	3,458,049	2,991,554	6,116,848	749,176	13,315,627
2009	3,542,715	2,983,355	6,117,824	750,511	13,394,404
2010	3,627,349	2,974,849	6,107,985	751,768	13,461,952
2011	3,726,394	2,971,081	6,090,144	753,514	13,541,133
2012	3,834,545	2,968,307	6,054,437	755,317	13,612,607

Pacificorp (Megawatthours)

	Residential	Commercial	Industrial	Other	Total
1991	11,123,096	8,965,388	17,679,137	1,875,158	39,642,779
1992	11,073,872	8,903,746	17,742,205	1,876,227	39,596,049
1993	11,130,144	8,947,208	18,344,567	1,900,099	40,322,018
1994	11,153,813	8,991,598	18,663,271	1,915,234	40,723,915
1995	11,137,155	8,989,353	18,644,827	1,917,556	40,688,892
1996	11,155,577	8,959,787	18,625,033	1,919,457	40,659,855
1997	11,186,750	8,925,016	18,657,736	1,921,772	40,691,274
1998	11,200,716	8,898,386	18,751,029	1,924,730	40,774,860
1999	11,205,840	8,882,781	18,868,151	1,928,123	40,884,894
2000	11,192,565	8,874,995	18,956,370	1,930,901	40,954,831
2001	11,177,712	8,865,914	19,059,250	1,932,824	41,035,700
2002	11,190,762	8,851,333	19,156,983	1,934,635	41,133,713
2003	11,252,914	8,829,492	19,156,847	1,935,214	41,174,467
2004	11,330,740	8,812,555	19,190,619	1,937,159	41,271,073
2005	11,411,753	8,808,641	19,303,056	1,941,618	41,465,068
2006	11,522,821	8,807,270	19,407,634	1,947,377	41,685,101
2007	11,661,262	8,809,327	19,492,389	1,953,006	41,915,983
2008	11,812,799	8,808,302	19,515,994	1,957,723	42,094,818
2009	11,990,876	8,802,999	19,485,770	1,961,497	42,241,142
2010	12,158,442	8,791,428	19,428,305	1,964,712	42,342,886
2011	12,331,891	8,774,902	19,332,721	1,966,977	42,406,490
2012	12,519,587	8,759,096	19,227,300	1,968,990	42,474,973

DETAILED MONTHLY PEAK & ENERGY FORECASTS

BY ZONE

Pacificorp Electric Operations - Firm Load - RAMPP II High Forecast

Pacific Division - Oregon

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		2419	2417	2325	2222	1957	1805	1853	1887	1861	2111	2302	2572
	ENERGY	1574	1835	1659	1591	1531	1456	1451	1442	1500	1484	1484	1651	1804
1992	PEAK		2517	2515	2419	2312	2036	1878	1928	1963	1936	2196	2395	2676
	ENERGY	1638	1909	1726	1656	1593	1515	1510	1500	1561	1544	1544	1718	1877
1993	PEAK		2600	2598	2499	2388	2103	1940	1991	2028	2001	2269	2474	2765
	ENERGY	1692	1973	1783	1710	1646	1565	1560	1550	1612	1595	1595	1775	1939
1994	PEAK		2683	2681	2579	2465	2171	2003	2055	2093	2065	2341	2553	2853
	ENERGY	1746	2036	1840	1765	1699	1615	1610	1599	1664	1646	1646	1832	2001
1995	PEAK		2784	2782	2676	2558	2252	2078	2132	2172	2142	2429	2649	2961
	ENERGY	1812	2112	1909	1832	1763	1676	1670	1659	1727	1708	1708	1900	2076
1996	PEAK		2901	2899	2788	2665	2347	2165	2222	2263	2232	2531	2760	3085
	ENERGY	1888	2201	1989	1908	1837	1746	1740	1729	1799	1780	1780	1980	2163
1997	PEAK		3012	3009	2895	2767	2436	2248	2307	2349	2317	2628	2866	3202
	ENERGY	1960	2285	2065	1981	1907	1813	1807	1795	1868	1848	1848	2056	2246
1998	PEAK		3121	3118	2999	2867	2524	2329	2390	2434	2401	2723	2969	3318
	ENERGY	2031	2368	2140	2053	1976	1878	1872	1860	1935	1915	1915	2130	2327
1999	PEAK		3254	3251	3127	2989	2632	2428	2492	2538	2503	2839	3096	3460
	ENERGY	2117	2469	2231	2140	2060	1958	1952	1939	2018	1996	1996	2221	2426
2000	PEAK		3383	3381	3252	3108	2737	2525	2591	2639	2603	2952	3219	3598
	ENERGY	2201	2567	2320	2226	2142	2036	2030	2017	2098	2076	2076	2309	2523
2001	PEAK		3511	3509	3375	3226	2840	2621	2689	2739	2702	3064	3341	3734
	ENERGY	2285	2664	2408	2310	2223	2113	2107	2093	2177	2155	2155	2397	2618
2002	PEAK		3638	3635	3496	3342	2943	2715	2786	2838	2799	3174	3461	3868
	ENERGY	2367	2760	2495	2393	2303	2189	2182	2168	2256	2232	2232	2483	2713
2003	PEAK		3767	3764	3620	3461	3047	2811	2885	2939	2898	3287	3584	4006
	ENERGY	2451	2858	2583	2478	2385	2267	2260	2245	2336	2311	2311	2571	2809
2004	PEAK		3890	3887	3739	3573	3147	2903	2979	3034	2993	3394	3701	4136
	ENERGY	2531	2951	2668	2559	2463	2341	2334	2318	2412	2387	2387	2655	2901
2005	PEAK		4011	4008	3855	3685	3245	2994	3072	3129	3086	3500	3817	4265
	ENERGY	2610	3043	2751	2639	2540	2414	2406	2391	2487	2461	2461	2738	2991
2006	PEAK		4128	4125	3968	3793	3340	3081	3162	3221	3177	3602	3928	4390
	ENERGY	2686	3132	2831	2716	2614	2485	2477	2461	2560	2533	2533	2818	3079
2007	PEAK		4235	4232	4071	3891	3426	3161	3244	3304	3259	3696	4030	4504
	ENERGY	2756	3214	2905	2786	2682	2549	2541	2525	2626	2599	2599	2891	3158
2008	PEAK		4341	4338	4172	3988	3512	3240	3325	3387	3340	3788	4131	4616
	ENERGY	2825	3294	2977	2856	2748	2613	2604	2587	2692	2664	2664	2963	3237
2009	PEAK		4449	4445	4276	4087	3599	3320	3407	3470	3423	3882	4233	4731
	ENERGY	2895	3375	3051	2927	2817	2678	2669	2652	2759	2730	2730	3037	3317
2010	PEAK		4558	4555	4381	4188	3688	3402	3491	3556	3508	3977	4337	4847
	ENERGY	2966	3459	3126	2999	2886	2744	2735	2717	2827	2797	2797	3111	3399
2011	PEAK		4666	4663	4485	4287	3775	3483	3574	3640	3591	4072	4440	4962
	ENERGY	3036	3540	3200	3070	2954	2809	2800	2781	2894	2863	2863	3185	3480
2012	PEAK		4754	4751	4570	4368	3846	3548	3641	3709	3658	4148	4524	5056
	ENERGY	3094	3607	3261	3128	3010	2862	2852	2834	2948	2917	2917	3245	3545

Pacificorp Electric Operations - Firm Load - RAMPP II High Forecast

Pacific Division - Washington

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		708	702	607	558	461	502	576	588	543	596	635	707
	ENERGY	436	531	462	420	404	369	391	412	432	425	423	447	516
1992	PEAK		737	731	632	581	480	522	600	612	565	621	661	736
	ENERGY	454	553	481	438	421	385	407	429	450	443	440	465	537
1993	PEAK		762	755	653	600	496	540	620	633	584	641	683	761
	ENERGY	469	571	497	452	435	397	421	443	465	457	455	481	555
1994	PEAK		787	780	675	620	512	557	641	654	603	663	706	786
	ENERGY	485	590	513	467	449	411	435	458	480	473	470	497	573
1995	PEAK		815	808	699	642	531	578	664	677	625	686	732	815
	ENERGY	502	612	532	484	466	425	451	474	498	490	487	515	594
1996	PEAK		851	843	729	670	554	602	692	707	652	716	763	850
	ENERGY	524	638	555	505	486	444	470	495	519	511	508	537	620
1997	PEAK		885	877	759	697	576	627	720	735	678	745	794	884
	ENERGY	545	664	577	525	505	462	489	515	540	531	529	559	645
1998	PEAK		918	910	787	723	598	650	747	762	703	773	823	917
	ENERGY	565	689	599	545	524	479	507	534	560	551	548	579	669
1999	PEAK		956	948	820	753	622	677	778	794	733	805	858	955
	ENERGY	589	717	624	568	546	499	528	556	584	574	571	604	697
2000	PEAK		993	984	851	782	646	703	808	825	761	835	890	991
	ENERGY	611	745	647	589	567	518	548	577	606	596	593	627	723
2001	PEAK		1028	1019	882	810	669	728	837	854	788	866	922	1027
	ENERGY	633	771	671	611	587	536	568	598	628	617	614	649	749
2002	PEAK		1064	1055	912	838	693	754	866	884	815	896	954	1063
	ENERGY	655	798	694	632	607	555	588	619	649	639	636	672	775
2003	PEAK		1101	1091	944	867	716	779	896	914	843	926	987	1099
	ENERGY	678	826	718	653	628	574	608	640	672	661	657	695	802
2004	PEAK		1137	1127	975	896	740	805	925	944	871	957	1020	1136
	ENERGY	700	853	742	675	649	593	628	661	694	683	679	718	828
2005	PEAK		1172	1162	1005	923	763	830	954	974	898	987	1051	1171
	ENERGY	722	879	764	696	669	611	647	681	715	704	700	740	854
2006	PEAK		1210	1200	1038	954	788	857	985	1005	927	1019	1086	1209
	ENERGY	745	908	789	719	691	631	669	704	739	727	723	764	882
2007	PEAK		1247	1236	1069	982	812	883	1015	1036	955	1050	1119	1246
	ENERGY	768	935	813	740	712	651	689	725	761	749	745	787	909
2008	PEAK		1284	1273	1101	1011	836	909	1045	1066	984	1081	1152	1282
	ENERGY	791	963	837	762	733	670	709	746	784	771	767	810	935
2009	PEAK		1321	1310	1133	1041	860	936	1075	1097	1012	1112	1185	1320
	ENERGY	814	991	862	784	754	689	730	768	806	793	789	834	963
2010	PEAK		1359	1348	1165	1071	885	963	1106	1129	1042	1144	1219	1358
	ENERGY	837	1020	887	807	776	709	751	790	830	816	812	858	990
2011	PEAK		1397	1385	1198	1101	909	989	1137	1160	1070	1176	1253	1395
	ENERGY	860	1048	911	829	798	729	772	812	853	839	835	882	1018
2012	PEAK		1430	1418	1226	1127	931	1013	1164	1188	1096	1204	1283	1429
	ENERGY	881	1073	933	849	817	746	790	832	873	859	854	903	1042

Pacificorp Electric Operations - Firm Load - RAMPP II High Forecast

Pacific Division - Idaho

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		51	47	49	41	35	28	32	32	30	45	44	56
	ENERGY	29	37	35	33	29	25	24	23	24	25	28	32	36
1992	PEAK		54	49	51	43	36	29	34	34	32	47	46	59
	ENERGY	31	39	36	35	31	27	25	24	25	26	29	34	38
1993	PEAK		56	52	54	45	38	31	35	35	33	50	49	62
	ENERGY	32	41	38	37	33	28	27	25	27	27	30	35	40
1994	PEAK		60	54	57	47	40	33	37	37	35	53	52	66
	ENERGY	34	43	40	39	34	30	28	27	28	29	32	37	42
1995	PEAK		63	58	60	50	43	35	40	40	37	56	55	70
	ENERGY	36	46	43	41	36	31	30	28	30	31	34	40	45
1996	PEAK		67	61	64	53	46	37	42	42	40	59	58	74
	ENERGY	38	49	45	44	39	33	32	30	32	33	36	42	48
1997	PEAK		71	65	67	56	48	39	44	44	42	63	61	78
	ENERGY	41	51	48	46	41	35	33	32	34	34	38	44	50
1998	PEAK		75	68	71	59	51	41	47	47	44	66	65	82
	ENERGY	43	54	51	49	43	37	35	33	36	36	40	47	53
1999	PEAK		79	72	75	63	54	43	50	50	47	70	69	87
	ENERGY	45	58	54	52	46	39	37	35	38	38	43	50	56
2000	PEAK		84	77	80	67	57	46	53	53	50	74	73	92
	ENERGY	48	61	57	55	48	42	40	38	40	41	45	53	60
2001	PEAK		88	81	84	70	60	48	55	55	52	78	77	97
	ENERGY	51	64	60	57	51	44	42	40	42	43	48	55	63
2002	PEAK		93	85	88	74	63	51	58	58	55	82	80	102
	ENERGY	53	67	63	60	54	46	44	42	44	45	50	58	66
2003	PEAK		97	89	93	78	66	53	61	61	58	86	85	107
	ENERGY	56	71	66	64	56	48	46	44	46	47	53	61	69
2004	PEAK		102	93	97	81	69	56	64	64	60	90	88	112
	ENERGY	58	74	69	66	59	51	48	46	49	49	55	64	72
2005	PEAK		107	98	102	85	73	58	67	67	63	95	93	118
	ENERGY	61	78	72	70	62	53	51	48	51	52	58	67	76
2006	PEAK		111	102	106	89	76	61	70	70	66	99	97	123
	ENERGY	64	81	76	73	64	55	53	50	53	54	60	70	79
2007	PEAK		116	106	111	93	79	63	73	73	69	103	101	128
	ENERGY	67	84	79	76	67	58	55	52	55	56	63	73	83
2008	PEAK		121	111	116	97	82	66	76	76	72	107	105	134
	ENERGY	70	88	82	79	70	60	57	54	58	59	66	76	86
2009	PEAK		127	116	121	101	86	69	80	80	75	112	110	139
	ENERGY	73	92	86	82	73	63	60	57	60	61	68	80	90
2010	PEAK		132	121	126	105	90	72	83	83	78	117	114	145
	ENERGY	76	96	89	86	76	65	62	59	63	64	71	83	94
2011	PEAK		137	126	131	109	93	75	86	86	81	122	119	151
	ENERGY	79	100	93	89	79	68	65	62	65	67	74	86	98
2012	PEAK		142	130	136	113	97	78	89	89	84	126	124	157
	ENERGY	82	104	97	93	82	71	67	64	68	69	77	90	101

Pacificorp Electric Operations - Firm Load - RAMPP II High Forecast

Pacific Division - Montana

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		161	149	147	133	103	102	103	101	96	123	138	161
	ENERGY	94	119	105	104	94	80	81	80	80	84	86	100	112
1992	PEAK		168	156	153	139	107	106	107	105	101	128	144	168
	ENERGY	98	124	110	109	98	83	84	83	83	88	90	104	117
1993	PEAK		174	162	160	145	112	111	112	109	105	134	150	175
	ENERGY	102	129	114	113	102	87	88	87	87	91	94	108	122
1994	PEAK		180	167	165	149	115	114	115	113	108	138	155	181
	ENERGY	105	134	118	117	106	90	90	90	90	94	97	112	126
1995	PEAK		187	174	171	155	120	119	120	117	112	143	161	188
	ENERGY	109	139	123	121	109	93	94	93	93	98	101	116	130
1996	PEAK		194	181	178	161	125	123	125	122	117	149	167	195
	ENERGY	114	144	128	126	114	97	98	97	97	102	105	121	136
1997	PEAK		202	188	185	168	130	128	129	127	121	155	174	203
	ENERGY	118	150	133	131	119	101	102	101	101	106	109	125	141
1998	PEAK		211	196	193	175	135	134	135	132	127	162	182	212
	ENERGY	123	156	138	137	124	105	106	105	105	111	114	131	147
1999	PEAK		222	206	203	184	142	141	142	139	133	170	191	223
	ENERGY	130	165	146	144	130	110	112	111	110	116	120	138	155
2000	PEAK		233	217	214	194	150	148	149	146	140	179	201	234
	ENERGY	136	173	153	151	137	116	117	116	116	122	126	145	163
2001	PEAK		245	227	224	203	157	155	157	153	147	187	211	246
	ENERGY	143	181	160	159	143	122	123	122	122	128	132	152	171
2002	PEAK		256	238	234	212	164	162	164	160	154	196	220	257
	ENERGY	149	190	168	166	150	127	128	127	127	134	138	159	179
2003	PEAK		269	250	246	223	172	171	172	168	161	206	231	270
	ENERGY	157	199	176	174	157	134	135	134	134	141	145	167	188
2004	PEAK		278	258	254	230	178	176	178	174	167	213	239	279
	ENERGY	162	206	182	180	163	138	139	138	138	146	150	172	194
2005	PEAK		290	270	266	241	186	184	186	182	174	222	250	291
	ENERGY	169	215	190	188	170	144	146	145	144	152	156	180	203
2006	PEAK		302	280	276	250	193	191	193	189	181	231	260	303
	ENERGY	176	224	198	196	177	150	151	150	150	158	162	187	211
2007	PEAK		314	292	288	261	201	199	201	197	189	241	270	315
	ENERGY	183	233	206	204	184	156	158	156	156	165	169	195	219
2008	PEAK		325	302	298	270	208	206	208	204	195	249	280	326
	ENERGY	190	241	213	211	191	162	163	162	162	170	175	202	227
2009	PEAK		337	313	309	279	216	214	216	211	202	258	290	338
	ENERGY	197	250	221	219	197	168	169	168	168	177	181	209	235
2010	PEAK		351	326	321	291	225	223	225	220	211	269	302	352
	ENERGY	205	260	230	228	206	174	176	175	174	184	189	218	245
2011	PEAK		365	339	334	303	234	232	234	229	219	280	314	367
	ENERGY	213	271	240	237	214	182	183	182	182	191	197	227	255
2012	PEAK		377	350	345	313	241	239	241	236	226	289	324	378
	ENERGY	220	280	247	244	221	187	189	188	187	198	203	234	263

Pacificorp Electric Operations - Firm Load - RAMPP II High Forecast

Pacific Division - California

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		146	141	134	138	127	133	148	130	118	123	133	153
	ENERGY	96	109	93	90	90	96	102	106	99	88	84	87	106
1992	PEAK		152	148	140	144	133	139	155	136	123	129	139	160
	ENERGY	100	114	97	94	94	100	107	111	103	92	88	91	110
1993	PEAK		159	154	146	150	138	145	161	142	128	134	144	167
	ENERGY	104	119	101	98	98	104	111	115	108	96	92	95	115
1994	PEAK		164	159	151	155	143	150	166	147	132	139	149	173
	ENERGY	108	123	105	102	101	108	115	119	111	99	95	98	119
1995	PEAK		171	165	157	161	149	156	173	153	138	144	155	180
	ENERGY	112	128	109	106	105	112	120	124	116	103	99	102	124
1996	PEAK		178	172	164	168	155	163	180	159	143	150	162	187
	ENERGY	117	133	114	110	110	117	125	129	121	107	103	106	129
1997	PEAK		184	179	170	174	161	169	187	165	149	156	168	194
	ENERGY	121	138	118	114	114	121	129	134	125	111	107	110	134
1998	PEAK		190	184	175	180	166	174	193	170	153	161	173	200
	ENERGY	125	143	121	118	117	125	133	138	129	115	110	114	138
1999	PEAK		197	191	182	187	172	181	200	177	159	167	180	208
	ENERGY	130	148	126	122	122	130	138	143	134	119	114	118	143
2000	PEAK		204	198	188	193	178	187	207	183	165	173	186	215
	ENERGY	134	153	130	126	126	134	143	148	139	123	118	122	148
2001	PEAK		211	204	194	199	184	193	214	188	170	178	192	222
	ENERGY	139	158	134	130	130	138	148	153	143	127	122	126	153
2002	PEAK		217	210	200	205	189	198	220	194	175	183	198	228
	ENERGY	143	163	139	134	134	143	152	158	147	131	126	130	157
2003	PEAK		224	217	206	212	196	205	228	201	181	190	204	236
	ENERGY	148	168	143	139	138	147	157	163	152	135	130	134	163
2004	PEAK		231	224	212	218	201	211	234	206	186	195	210	243
	ENERGY	152	173	147	143	142	151	162	168	156	139	134	138	167
2005	PEAK		237	230	218	224	206	217	240	212	191	200	216	249
	ENERGY	156	178	151	147	146	156	166	172	161	143	137	142	172
2006	PEAK		243	236	224	230	212	222	247	218	196	206	221	256
	ENERGY	160	182	155	151	150	160	170	177	165	147	141	145	176
2007	PEAK		249	242	229	236	217	228	253	223	201	211	227	263
	ENERGY	164	187	159	154	154	164	175	181	169	150	144	149	181
2008	PEAK		256	248	236	242	223	234	260	229	207	217	233	270
	ENERGY	169	192	164	159	158	168	180	186	174	154	148	153	186
2009	PEAK		264	255	242	249	230	241	267	236	213	223	240	278
	ENERGY	173	198	168	163	163	173	185	192	179	159	153	158	191
2010	PEAK		271	263	249	256	236	248	275	243	219	229	247	285
	ENERGY	178	203	173	168	167	178	190	197	184	163	157	162	196
2011	PEAK		278	270	256	263	242	254	282	249	224	235	254	293
	ENERGY	183	209	178	172	172	183	195	202	189	168	161	166	202
2012	PEAK		285	276	262	269	248	260	289	255	229	241	259	300
	ENERGY	187	213	182	176	176	187	199	207	193	171	165	170	206

Pacificorp Electric Operations - Firm Load - RAMPP II High Forecast

Pacific Division - Wyoming

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		1025	999	995	954	883	993	943	954	954	924	981	1023
	ENERGY	885	943	951	902	893	802	866	851	857	867	859	905	933
1992	PEAK		1065	1039	1034	992	918	1032	981	991	992	960	1020	1064
	ENERGY	920	980	988	938	928	834	900	885	891	901	893	941	970
1993	PEAK		1122	1094	1090	1045	967	1088	1034	1045	1045	1012	1074	1121
	ENERGY	970	1033	1041	988	978	878	948	933	939	949	941	992	1022
1994	PEAK		1178	1149	1144	1097	1015	1142	1085	1096	1097	1062	1128	1177
	ENERGY	1018	1084	1093	1037	1027	922	995	979	985	996	987	1041	1073
1995	PEAK		1225	1194	1189	1140	1055	1187	1128	1140	1140	1104	1172	1223
	ENERGY	1058	1127	1136	1078	1068	959	1035	1018	1024	1036	1026	1082	1115
1996	PEAK		1278	1247	1241	1190	1102	1239	1177	1190	1190	1153	1224	1277
	ENERGY	1104	1176	1186	1125	1114	1001	1080	1062	1069	1081	1071	1130	1164
1997	PEAK		1335	1302	1296	1243	1151	1294	1229	1243	1243	1204	1278	1334
	ENERGY	1153	1228	1239	1175	1164	1045	1128	1110	1117	1129	1119	1180	1216
1998	PEAK		1395	1360	1354	1298	1202	1351	1284	1298	1298	1257	1335	1393
	ENERGY	1205	1283	1294	1228	1215	1091	1178	1159	1166	1179	1169	1232	1270
1999	PEAK		1461	1425	1419	1360	1259	1416	1345	1360	1360	1317	1398	1459
	ENERGY	1262	1344	1356	1286	1274	1144	1234	1214	1222	1236	1224	1291	1330
2000	PEAK		1528	1490	1484	1422	1317	1481	1407	1422	1423	1378	1462	1526
	ENERGY	1320	1406	1418	1345	1332	1196	1291	1270	1278	1292	1280	1350	1391
2001	PEAK		1598	1558	1551	1487	1377	1548	1471	1487	1488	1440	1529	1596
	ENERGY	1380	1470	1482	1406	1393	1250	1350	1328	1336	1351	1339	1412	1455
2002	PEAK		1668	1626	1619	1553	1437	1616	1536	1552	1553	1504	1596	1666
	ENERGY	1441	1534	1547	1468	1454	1305	1409	1386	1395	1410	1398	1474	1519
2003	PEAK		1737	1694	1686	1617	1497	1683	1599	1617	1617	1566	1662	1735
	ENERGY	1500	1598	1611	1529	1514	1359	1467	1443	1452	1469	1455	1535	1581
2004	PEAK		1805	1760	1753	1680	1555	1749	1662	1680	1681	1627	1728	1803
	ENERGY	1559	1661	1675	1589	1573	1413	1525	1500	1509	1527	1513	1595	1644
2005	PEAK		1872	1826	1818	1743	1613	1814	1724	1743	1743	1688	1792	1870
	ENERGY	1617	1723	1737	1648	1632	1465	1582	1556	1566	1583	1569	1655	1705
2006	PEAK		1945	1897	1889	1811	1676	1885	1791	1810	1811	1754	1862	1943
	ENERGY	1680	1790	1805	1712	1695	1522	1643	1616	1627	1645	1630	1719	1771
2007	PEAK		2016	1966	1957	1876	1737	1953	1856	1876	1877	1817	1929	2013
	ENERGY	1741	1855	1870	1774	1757	1578	1703	1675	1686	1705	1689	1781	1835
2008	PEAK		2084	2032	2024	1940	1796	2020	1919	1940	1941	1879	1995	2082
	ENERGY	1800	1918	1934	1835	1817	1631	1761	1732	1743	1763	1746	1842	1898
2009	PEAK		2152	2098	2089	2003	1854	2085	1981	2003	2003	1940	2059	2149
	ENERGY	1859	1980	1996	1894	1875	1684	1818	1788	1799	1820	1803	1901	1959
2010	PEAK		2220	2165	2156	2067	1913	2151	2044	2066	2067	2002	2125	2218
	ENERGY	1918	2043	2060	1954	1935	1738	1876	1845	1857	1878	1860	1962	2022
2011	PEAK		2290	2233	2224	2132	1974	2219	2109	2132	2133	2065	2192	2288
	ENERGY	1978	2107	2125	2016	1996	1793	1935	1903	1915	1937	1919	2024	2085
2012	PEAK		2358	2300	2290	2195	2032	2285	2171	2195	2196	2126	2257	2355
	ENERGY	2037	2170	2188	2076	2056	1846	1992	1960	1972	1994	1976	2084	2147

Pacificorp Electric Operations - Firm Load - RAMPP II High Forecast

Utah Division - Idaho

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		283	276	273	157	175	378	485	413	310	258	271	282
	ENERGY	229	207	183	189	118	169	288	429	330	227	209	182	210
1992	PEAK		297	280	290	168	182	397	509	440	334	279	295	300
	ENERGY	243	217	194	201	126	175	302	444	352	247	227	201	224
1993	PEAK		317	299	310	183	197	422	539	467	356	298	314	321
	ENERGY	261	234	209	216	139	189	322	470	374	265	243	217	240
1994	PEAK		335	316	327	196	210	445	566	491	375	316	332	339
	ENERGY	277	248	223	231	150	202	340	494	395	281	259	231	255
1995	PEAK		354	334	345	210	223	469	594	516	395	335	351	358
	ENERGY	294	264	238	245	162	216	359	519	416	297	275	246	271
1996	PEAK		376	355	367	226	239	496	627	545	418	356	372	380
	ENERGY	313	282	254	262	175	232	381	548	440	317	293	263	289
1997	PEAK		396	375	387	241	254	522	658	573	440	376	392	401
	ENERGY	331	298	270	278	188	247	402	575	463	335	310	279	306
1998	PEAK		417	394	406	256	268	548	689	600	462	397	412	422
	ENERGY	349	316	292	300	189	272	403	586	476	358	314	300	317
1999	PEAK		445	416	430	290	278	605	749	649	489	438	436	458
	ENERGY	374	340	315	322	207	294	432	625	509	384	339	323	342
2000	PEAK		473	443	458	311	299	641	792	688	519	466	464	487
	ENERGY	399	364	337	345	224	314	461	663	541	410	363	345	366
2001	PEAK		501	469	484	331	319	676	833	725	549	494	491	515
	ENERGY	424	386	358	366	242	334	489	700	572	434	386	367	389
2002	PEAK		526	494	509	350	337	709	872	759	576	519	516	541
	ENERGY	446	407	378	386	257	353	515	733	600	457	408	387	410
2003	PEAK		550	517	533	368	354	739	908	791	602	543	540	566
	ENERGY	467	427	397	406	272	371	539	766	628	478	428	406	430
2004	PEAK		574	540	556	386	372	770	945	824	628	567	564	591
	ENERGY	489	447	415	425	288	388	564	798	655	500	448	425	450
2005	PEAK		596	561	578	402	388	798	978	853	652	588	586	613
	ENERGY	508	465	432	442	301	404	586	827	679	519	467	443	469
2006	PEAK		625	588	605	423	408	834	1021	891	682	616	614	642
	ENERGY	533	488	454	464	319	425	615	864	711	545	491	465	492
2007	PEAK		649	611	629	441	425	864	1057	923	708	640	637	666
	ENERGY	554	508	473	483	334	442	639	896	738	566	511	484	512
2008	PEAK		671	632	650	458	441	892	1090	953	732	662	659	689
	ENERGY	574	526	490	500	347	458	661	926	763	586	530	501	531
2009	PEAK		691	651	670	473	456	918	1121	980	753	682	679	710
	ENERGY	591	543	506	516	360	473	682	952	786	604	547	517	548
2010	PEAK		713	678	696	477	482	925	1137	999	782	690	705	726
	ENERGY	610	560	516	528	385	478	724	997	820	618	578	529	572
2011	PEAK		736	699	718	493	498	954	1171	1029	805	712	727	748
	ENERGY	630	578	533	545	399	494	746	1027	845	638	597	547	590
2012	PEAK		753	715	735	506	511	976	1197	1052	824	729	744	766
	ENERGY	645	592	547	559	410	506	764	1050	864	653	611	560	605

Pacificorp Electric Operations - Firm Load - RAMPP II High Forecast

Utah Division - Wyoming

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		324	306	287	276	264	227	245	277	240	282	277	304
	ENERGY	269	305	309	257	269	259	275	244	269	242	265	254	287
1992	PEAK		334	315	296	284	272	234	252	285	247	290	285	313
	ENERGY	277	314	318	264	277	267	283	251	277	250	273	262	296
1993	PEAK		354	334	314	301	289	248	267	302	262	308	302	332
	ENERGY	294	333	337	280	294	283	300	266	294	265	289	277	314
1994	PEAK		373	352	331	317	304	261	281	319	276	324	319	350
	ENERGY	310	351	356	295	310	298	316	280	310	279	305	292	331
1995	PEAK		387	364	342	328	315	271	291	330	286	336	330	362
	ENERGY	321	363	368	306	321	309	327	290	321	289	315	303	342
1996	PEAK		402	379	357	342	328	282	303	344	298	350	344	377
	ENERGY	334	378	383	318	334	321	341	302	334	301	328	315	357
1997	PEAK		420	396	372	357	342	294	317	359	311	365	359	393
	ENERGY	349	395	400	332	348	335	356	315	349	314	343	329	372
1998	PEAK		438	413	388	372	357	307	330	374	324	381	374	410
	ENERGY	364	412	417	347	363	350	371	329	364	327	358	343	388
1999	PEAK		457	431	405	388	372	320	344	390	338	397	390	428
	ENERGY	379	429	435	361	379	365	387	343	379	341	373	358	405
2000	PEAK		476	448	421	404	388	333	359	406	352	413	406	445
	ENERGY	395	447	453	376	394	380	403	357	395	355	388	372	421
2001	PEAK		495	467	439	421	404	347	373	423	366	430	423	464
	ENERGY	411	465	472	392	411	395	419	372	411	370	404	388	439
2002	PEAK		515	486	456	438	420	361	388	440	381	448	440	482
	ENERGY	428	484	491	407	427	411	436	387	428	385	420	403	456
2003	PEAK		534	504	473	454	436	374	403	456	395	464	456	500
	ENERGY	444	502	509	423	443	427	452	401	444	399	436	418	473
2004	PEAK		552	521	489	469	450	387	416	472	409	480	472	517
	ENERGY	459	519	526	437	458	441	468	415	459	413	451	432	489
2005	PEAK		570	537	505	484	465	399	430	487	422	495	487	534
	ENERGY	473	536	543	451	473	455	483	428	473	426	465	446	505
2006	PEAK		588	554	521	499	479	412	443	502	435	511	502	551
	ENERGY	488	553	560	465	488	470	498	442	488	439	480	460	521
2007	PEAK		606	571	537	514	494	424	457	517	448	526	517	567
	ENERGY	503	569	577	479	502	484	513	455	503	453	494	474	537
2008	PEAK		622	587	551	528	507	436	469	532	460	541	531	583
	ENERGY	517	585	593	492	516	497	527	467	517	465	508	487	551
2009	PEAK		638	602	565	542	520	447	481	545	472	555	545	598
	ENERGY	530	600	608	505	529	510	540	479	530	477	521	500	565
2010	PEAK		654	616	579	555	533	458	493	559	484	568	558	612
	ENERGY	543	614	623	517	542	522	554	491	543	489	534	512	579
2011	PEAK		669	631	593	569	546	469	505	572	495	582	572	627
	ENERGY	556	629	638	530	555	535	567	503	556	500	546	524	593
2012	PEAK		685	646	607	582	558	480	516	585	507	595	585	641
	ENERGY	569	644	652	542	568	547	580	514	569	512	559	536	607

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Utah Division - Utah

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		1868	1920	1856	1551	1724	2049	2126	2127	2027	1660	1769	1922
	ENERGY	1455	1512	1476	1475	1276	1356	1436	1574	1548	1448	1387	1399	1564
1992	PEAK		1989	2035	1979	1655	1834	2182	2264	2271	2166	1775	1893	2050
	ENERGY	1552	1609	1573	1574	1362	1441	1528	1670	1654	1551	1484	1500	1668
1993	PEAK		2107	2156	2097	1756	1943	2312	2398	2406	2294	1883	2006	2172
	ENERGY	1647	1707	1669	1669	1446	1529	1621	1771	1754	1646	1575	1592	1769
1994	PEAK		2225	2276	2214	1857	2052	2442	2532	2540	2422	1990	2119	2293
	ENERGY	1741	1804	1764	1764	1529	1617	1714	1871	1854	1740	1665	1683	1869
1995	PEAK		2350	2403	2338	1963	2167	2580	2674	2682	2557	2103	2238	2422
	ENERGY	1840	1907	1865	1865	1617	1710	1812	1977	1959	1839	1760	1779	1975
1996	PEAK		2476	2532	2463	2070	2284	2718	2817	2825	2693	2217	2358	2552
	ENERGY	1940	2010	1966	1967	1706	1804	1911	2084	2066	1939	1857	1876	2082
1997	PEAK		2587	2645	2573	2164	2386	2841	2944	2951	2813	2318	2464	2667
	ENERGY	2029	2102	2056	2056	1785	1886	1998	2179	2160	2028	1942	1962	2177
1998	PEAK		2705	2765	2690	2264	2495	2970	3077	3085	2940	2424	2576	2788
	ENERGY	2122	2200	2157	2156	1856	1985	2071	2263	2249	2126	2018	2058	2271
1999	PEAK		2837	2895	2817	2390	2607	3137	3245	3246	3079	2558	2698	2931
	ENERGY	2228	2309	2265	2263	1951	2084	2175	2377	2361	2232	2120	2161	2384
2000	PEAK		2974	3035	2953	2506	2733	3287	3400	3402	3227	2682	2829	3073
	ENERGY	2337	2422	2375	2374	2047	2186	2283	2493	2477	2341	2225	2267	2501
2001	PEAK		3113	3177	3092	2625	2862	3441	3559	3561	3378	2809	2962	3217
	ENERGY	2449	2537	2488	2486	2146	2290	2393	2612	2595	2453	2332	2375	2619
2002	PEAK		3255	3322	3233	2745	2993	3597	3720	3722	3531	2937	3097	3363
	ENERGY	2561	2653	2602	2600	2246	2395	2504	2732	2714	2565	2440	2484	2740
2003	PEAK		3397	3467	3374	2866	3124	3753	3881	3883	3685	3066	3233	3510
	ENERGY	2675	2770	2717	2715	2347	2501	2615	2854	2834	2679	2549	2594	2861
2004	PEAK		3538	3610	3513	2986	3254	3908	4041	4043	3837	3193	3367	3654
	ENERGY	2786	2886	2830	2828	2446	2606	2726	2973	2953	2790	2656	2702	2980
2005	PEAK		3677	3753	3652	3105	3383	4062	4200	4202	3988	3320	3500	3799
	ENERGY	2898	3001	2943	2941	2545	2710	2836	3092	3071	2902	2763	2810	3099
2006	PEAK		3835	3914	3809	3239	3528	4236	4380	4382	4159	3463	3651	3962
	ENERGY	3024	3131	3070	3069	2657	2827	2960	3227	3204	3028	2884	2932	3233
2007	PEAK		3985	4067	3959	3367	3667	4401	4550	4552	4321	3600	3794	4117
	ENERGY	3143	3255	3192	3190	2764	2939	3078	3354	3331	3147	2998	3048	3361
2008	PEAK		4132	4217	4105	3492	3803	4563	4717	4720	4480	3733	3934	4268
	ENERGY	3260	3375	3310	3308	2868	3048	3193	3480	3455	3264	3111	3162	3486
2009	PEAK		4276	4363	4247	3614	3935	4720	4880	4883	4635	3863	4071	4416
	ENERGY	3374	3493	3426	3424	2969	3155	3306	3602	3576	3378	3220	3273	3608
2010	PEAK		4427	4522	4401	3730	4085	4866	5035	5043	4803	3986	4219	4565
	ENERGY	3494	3616	3541	3540	3087	3256	3444	3745	3713	3493	3348	3384	3742
2011	PEAK		4582	4680	4555	3861	4228	5036	5211	5219	4970	4126	4367	4725
	ENERGY	3617	3744	3666	3665	3197	3371	3565	3877	3843	3616	3467	3503	3874
2012	PEAK		4731	4833	4703	3988	4365	5200	5381	5389	5132	4262	4510	4879
	ENERGY	3736	3866	3787	3785	3303	3482	3683	4004	3969	3735	3581	3619	4001

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Utah Division

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		2474	2501	2416	1983	2162	2654	2855	2815	2576	2200	2317	2508
	ENERGY	1953	2023	1967	1921	1662	1783	1999	2247	2147	1917	1862	1834	2061
1992	PEAK		2619	2630	2565	2107	2288	2812	3023	2995	2746	2344	2473	2662
	ENERGY	2072	2141	2085	2040	1765	1883	2113	2365	2285	2047	1984	1962	2188
1993	PEAK		2777	2789	2720	2240	2428	2981	3203	3174	2911	2489	2623	2823
	ENERGY	2201	2274	2215	2167	1878	2002	2243	2508	2424	2174	2108	2085	2323
1994	PEAK		2933	2945	2872	2370	2565	3148	3379	3349	3072	2630	2770	2981
	ENERGY	2327	2404	2343	2291	1988	2118	2370	2647	2560	2299	2229	2206	2456
1995	PEAK		3089	3102	3026	2501	2705	3318	3559	3527	3237	2773	2919	3141
	ENERGY	2453	2535	2470	2417	2099	2235	2498	2788	2697	2425	2351	2327	2590
1996	PEAK		3253	3266	3186	2638	2850	3495	3747	3713	3408	2923	3074	3308
	ENERGY	2586	2671	2604	2548	2215	2357	2633	2935	2841	2556	2479	2454	2729
1997	PEAK		3402	3416	3332	2762	2981	3656	3917	3882	3563	3059	3215	3460
	ENERGY	2707	2796	2726	2668	2321	2469	2756	3071	2972	2676	2595	2570	2856
1998	PEAK		3558	3572	3485	2893	3119	3824	4096	4059	3726	3202	3363	3620
	ENERGY	2834	2927	2866	2802	2408	2606	2843	3178	3088	2811	2690	2701	2975
1999	PEAK		3739	3741	3653	3067	3258	4061	4339	4287	3905	3394	3524	3818
	ENERGY	2981	3078	3014	2947	2536	2741	2993	3344	3248	2957	2832	2842	3130
2000	PEAK		3923	3926	3833	3221	3421	4261	4551	4497	4098	3563	3699	4006
	ENERGY	3131	3231	3165	3095	2666	2879	3146	3512	3411	3105	2976	2985	3286
2001	PEAK		4110	4113	4016	3377	3585	4464	4767	4709	4293	3734	3876	4197
	ENERGY	3283	3387	3317	3245	2799	3019	3300	3682	3577	3256	3122	3130	3446
2002	PEAK		4297	4301	4199	3533	3750	4666	4981	4921	4488	3905	4053	4387
	ENERGY	3434	3543	3470	3394	2931	3158	3454	3852	3741	3406	3268	3274	3605
2003	PEAK		4482	4487	4381	3688	3915	4866	5193	5132	4682	4074	4229	4577
	ENERGY	3585	3699	3622	3543	3063	3297	3606	4019	3904	3555	3413	3418	3763
2004	PEAK		4665	4670	4560	3841	4077	5064	5403	5340	4874	4241	4402	4763
	ENERGY	3733	3851	3771	3690	3192	3434	3756	4185	4065	3702	3555	3560	3919
2005	PEAK		4844	4850	4736	3991	4236	5258	5608	5543	5061	4405	4572	4946
	ENERGY	3878	4001	3918	3834	3319	3568	3903	4346	4222	3846	3695	3699	4072
2006	PEAK		5049	5056	4936	4162	4417	5481	5844	5776	5276	4592	4767	5155
	ENERGY	4044	4171	4085	3998	3464	3721	4071	4532	4402	4011	3854	3858	4246
2007	PEAK		5241	5248	5125	4322	4587	5689	6064	5994	5477	4767	4949	5351
	ENERGY	4199	4331	4241	4152	3600	3864	4229	4705	4571	4165	4004	4006	4409
2008	PEAK		5426	5435	5307	4478	4752	5890	6277	6205	5672	4936	5125	5541
	ENERGY	4349	4485	4393	4300	3731	4002	4380	4871	4733	4314	4148	4150	4567
2009	PEAK		5606	5616	5483	4628	4912	6085	6483	6409	5861	5100	5295	5724
	ENERGY	4495	4635	4539	4445	3858	4137	4527	5032	4890	4458	4288	4290	4720
2010	PEAK		5793	5816	5676	4761	5099	6248	6664	6600	6067	5245	5483	5902
	ENERGY	4646	4791	4680	4586	4015	4256	4721	5234	5076	4599	4460	4424	4894
2011	PEAK		5986	6010	5866	4923	5271	6458	6885	6819	6270	5421	5666	6099
	ENERGY	4802	4951	4837	4741	4151	4400	4878	5407	5245	4754	4610	4574	5058
2012	PEAK		6168	6194	6045	5076	5434	6655	7093	7026	6462	5587	5839	6285
	ENERGY	4949	5103	4986	4887	4280	4537	5026	5569	5403	4900	4752	4715	5213

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Pacific Division

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		4509	4455	4257	4046	3565	3563	3655	3692	3602	3922	4233	4674
	ENERGY	3114	3575	3305	3141	3042	2828	2915	2914	2992	2973	2964	3223	3507
1992	PEAK		4692	4637	4430	4210	3710	3708	3804	3842	3748	4081	4405	4864
	ENERGY	3241	3720	3439	3269	3166	2943	3033	3032	3114	3093	3085	3353	3649
1993	PEAK		4873	4815	4601	4373	3854	3854	3953	3992	3895	4239	4575	5051
	ENERGY	3369	3866	3575	3399	3292	3060	3154	3153	3237	3216	3207	3486	3792
1994	PEAK		5052	4991	4770	4534	3997	3999	4100	4141	4040	4395	4743	5235
	ENERGY	3496	4010	3710	3527	3416	3175	3274	3272	3359	3338	3328	3617	3934
1995	PEAK		5245	5182	4952	4707	4150	4151	4256	4299	4195	4563	4924	5435
	ENERGY	3629	4163	3852	3662	3547	3296	3399	3397	3487	3465	3455	3755	4084
1996	PEAK		5469	5403	5164	4908	4327	4329	4438	4482	4374	4758	5134	5668
	ENERGY	3785	4342	4017	3819	3699	3437	3544	3542	3636	3614	3603	3916	4259
1997	PEAK		5689	5620	5372	5105	4501	4504	4617	4663	4551	4950	5341	5895
	ENERGY	3938	4517	4180	3973	3849	3576	3688	3685	3784	3760	3749	4074	4431
1998	PEAK		5909	5837	5580	5302	4675	4679	4796	4844	4727	5141	5547	6122
	ENERGY	4092	4693	4343	4129	3999	3715	3832	3829	3931	3907	3896	4233	4604
1999	PEAK		6169	6094	5826	5536	4882	4886	5008	5058	4936	5368	5792	6392
	ENERGY	4273	4900	4536	4312	4177	3880	4002	3999	4105	4080	4069	4421	4808
2000	PEAK		6425	6346	6068	5766	5084	5089	5215	5267	5141	5591	6032	6657
	ENERGY	4451	5105	4726	4492	4352	4042	4169	4166	4276	4250	4239	4606	5008
2001	PEAK		6681	6598	6309	5995	5287	5293	5423	5477	5346	5813	6272	6921
	ENERGY	4630	5309	4916	4673	4527	4204	4337	4333	4448	4421	4409	4791	5208
2002	PEAK		6935	6849	6550	6224	5489	5496	5630	5686	5551	6035	6510	7184
	ENERGY	4808	5513	5105	4854	4702	4366	4504	4499	4618	4591	4579	4975	5408
2003	PEAK		7195	7105	6796	6457	5694	5703	5841	5900	5759	6261	6754	7453
	ENERGY	4990	5720	5298	5037	4879	4530	4674	4669	4792	4765	4752	5163	5612
2004	PEAK		7442	7349	7030	6679	5890	5900	6042	6103	5958	6476	6986	7709
	ENERGY	5163	5918	5483	5212	5049	4687	4836	4831	4959	4930	4917	5342	5806
2005	PEAK		7689	7593	7264	6901	6086	6097	6243	6306	6156	6692	7218	7965
	ENERGY	5336	6116	5667	5387	5219	4844	4998	4993	5124	5095	5082	5521	6000
2006	PEAK		7940	7840	7500	7126	6285	6298	6448	6513	6358	6910	7453	8223
	ENERGY	5512	6317	5854	5565	5391	5004	5163	5158	5293	5264	5250	5703	6197
2007	PEAK		8178	8074	7725	7339	6473	6489	6642	6709	6550	7117	7676	8469
	ENERGY	5680	6508	6032	5735	5556	5155	5320	5314	5454	5424	5409	5877	6385
2008	PEAK		8412	8304	7946	7548	6657	6676	6833	6902	6738	7321	7895	8710
	ENERGY	5844	6696	6207	5901	5717	5304	5475	5468	5612	5581	5566	6046	6569
2009	PEAK		8649	8537	8169	7760	6845	6865	7026	7097	6929	7527	8117	8955
	ENERGY	6010	6886	6384	6069	5880	5454	5630	5624	5771	5740	5724	6218	6755
2010	PEAK		8892	8777	8399	7978	7036	7059	7225	7297	7124	7738	8345	9206
	ENERGY	6180	7080	6565	6242	6046	5608	5790	5783	5934	5902	5887	6394	6946
2011	PEAK		9134	9016	8628	8195	7228	7253	7422	7496	7318	7949	8572	9456
	ENERGY	6350	7275	6747	6414	6213	5762	5949	5942	6097	6065	6049	6570	7137
2012	PEAK		9347	9225	8828	8385	7396	7424	7596	7672	7490	8134	8771	9675
	ENERGY	6501	7446	6907	6566	6361	5898	6091	6083	6242	6209	6192	6726	7305

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Total Company

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		6983	6956	6673	6028	5727	6217	6510	6507	6178	6122	6550	7182
	ENERGY	5067	5598	5272	5062	4704	4611	4914	5161	5139	4890	4826	5057	5568
1992	PEAK		7312	7267	6995	6317	5998	6519	6827	6837	6495	6426	6878	7526
	ENERGY	5313	5861	5523	5308	4931	4826	5146	5397	5398	5141	5069	5315	5837
1993	PEAK		7651	7604	7321	6612	6282	6835	7156	7166	6806	6728	7198	7874
	ENERGY	5570	6140	5790	5565	5170	5061	5397	5660	5660	5391	5315	5571	6116
1994	PEAK		7985	7936	7642	6903	6563	7146	7479	7489	7112	7026	7513	8217
	ENERGY	5822	6414	6053	5818	5405	5293	5644	5918	5918	5637	5557	5822	6390
1995	PEAK		8334	8284	7978	7208	6855	7469	7815	7826	7431	7337	7843	8577
	ENERGY	6083	6698	6322	6079	5646	5531	5897	6184	6184	5890	5806	6082	6674
1996	PEAK		8722	8669	8350	7545	7177	7824	8185	8195	7782	7681	8208	8976
	ENERGY	6371	7012	6621	6367	5914	5795	6177	6477	6477	6170	6082	6370	6988
1997	PEAK		9091	9036	8704	7867	7483	8160	8535	8545	8114	8009	8556	9356
	ENERGY	6645	7313	6906	6641	6170	6045	6444	6756	6756	6436	6345	6644	7287
1998	PEAK		9467	9409	9064	8195	7795	8503	8892	8903	8453	8343	8910	9742
	ENERGY	6926	7619	7210	6931	6408	6322	6675	7007	7019	6718	6586	6935	7579
1999	PEAK		9908	9835	9479	8603	8140	8947	9346	9344	8841	8762	9316	10210
	ENERGY	7254	7978	7550	7259	6713	6621	6995	7342	7353	7037	6900	7263	7937
2000	PEAK		10348	10272	9901	8987	8505	9350	9767	9764	9239	9154	9731	10663
	ENERGY	7582	8336	7890	7587	7018	6921	7315	7678	7687	7356	7214	7590	8294
2001	PEAK		10791	10711	10326	9372	8872	9757	10190	10187	9639	9547	10148	11118
	ENERGY	7913	8696	8233	7918	7326	7223	7637	8015	8024	7677	7531	7920	8654
2002	PEAK		11232	11149	10749	9756	9239	10162	10611	10608	10039	9939	10563	11571
	ENERGY	8242	9056	8576	8248	7633	7524	7957	8351	8359	7997	7847	8250	9013
2003	PEAK		11677	11592	11177	10145	9609	10569	11034	11032	10441	10335	10983	12030
	ENERGY	8574	9419	8920	8580	7942	7827	8280	8688	8697	8320	8164	8581	9375
2004	PEAK		12107	12019	11590	10520	9967	10965	11446	11443	10831	10718	11389	12472
	ENERGY	8896	9769	9254	8902	8241	8121	8592	9016	9024	8632	8472	8902	9725
2005	PEAK		12534	12443	11999	10892	10322	11355	11852	11849	11217	11097	11791	12911
	ENERGY	9214	10116	9584	9221	8538	8412	8901	9338	9346	8941	8776	9220	10072
2006	PEAK		12989	12896	12437	11287	10701	11779	12292	12289	11634	11502	12220	13378
	ENERGY	9556	10488	9939	9563	8855	8724	9235	9689	9696	9275	9104	9561	10443
2007	PEAK		13419	13323	12850	11661	11060	12178	12707	12703	12027	11884	12625	13820
	ENERGY	9879	10839	10274	9887	9155	9019	9549	10019	10025	9589	9413	9883	10794
2008	PEAK		13838	13739	13252	12025	11409	12566	13110	13107	12410	12257	13020	14250
	ENERGY	10193	11181	10600	10202	9448	9306	9855	10340	10345	9895	9714	10197	11136
2009	PEAK		14254	14153	13652	12388	11756	12950	13509	13506	12789	12627	13412	14679
	ENERGY	10505	11521	10923	10514	9738	9591	10158	10656	10661	10198	10012	10508	11476
2010	PEAK		14685	14593	14075	12739	12135	13307	13888	13897	13191	12983	13828	15107
	ENERGY	10826	11871	11245	10827	10061	9865	10511	11017	11010	10501	10347	10819	11840
2011	PEAK		15120	15026	14493	13117	12498	13710	14307	14315	13588	13370	14238	15555
	ENERGY	11152	12226	11584	11154	10364	10163	10828	11350	11342	10819	10659	11144	12195
2012	PEAK		15515	15418	14873	13461	12829	14079	14689	14698	13952	13721	14610	15960
	ENERGY	11450	12550	11893	11453	10641	10435	11117	11653	11645	11109	10944	11441	12518

Pacificorp Electric Operations - Firm Load - RAMPP II Medium High Forecast

Pacific Division - Oregon

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		2388	2386	2295	2194	1932	1782	1829	1863	1837	2084	2272	2539
	ENERGY	1554	1812	1638	1571	1512	1437	1433	1423	1481	1465	1465	1630	1781
1992	PEAK		2446	2444	2351	2247	1979	1825	1873	1908	1882	2134	2327	2601
	ENERGY	1592	1856	1677	1609	1549	1472	1467	1458	1517	1501	1501	1670	1824
1993	PEAK		2499	2497	2402	2296	2022	1865	1914	1950	1923	2181	2378	2658
	ENERGY	1626	1896	1714	1644	1582	1504	1499	1490	1550	1534	1534	1706	1864
1994	PEAK		2551	2549	2452	2343	2064	1904	1954	1990	1963	2226	2427	2712
	ENERGY	1660	1935	1749	1678	1615	1535	1530	1520	1582	1565	1565	1741	1902
1995	PEAK		2617	2616	2516	2405	2117	1954	2005	2042	2014	2284	2491	2783
	ENERGY	1703	1986	1795	1722	1657	1575	1570	1560	1623	1606	1606	1787	1952
1996	PEAK		2696	2694	2591	2476	2181	2012	2065	2103	2074	2352	2565	2866
	ENERGY	1754	2045	1849	1773	1707	1622	1617	1607	1672	1654	1654	1840	2010
1997	PEAK		2765	2763	2658	2541	2237	2064	2118	2157	2128	2413	2631	2941
	ENERGY	1799	2098	1897	1819	1751	1665	1659	1648	1715	1697	1697	1888	2062
1998	PEAK		2831	2829	2721	2601	2290	2113	2169	2209	2179	2471	2694	3011
	ENERGY	1842	2148	1942	1863	1793	1704	1699	1688	1756	1737	1737	1933	2111
1999	PEAK		2918	2916	2804	2680	2360	2178	2235	2276	2245	2546	2776	3103
	ENERGY	1899	2214	2001	1919	1847	1756	1751	1739	1809	1790	1790	1992	2176
2000	PEAK		3000	2998	2883	2756	2427	2239	2298	2340	2308	2617	2854	3190
	ENERGY	1952	2276	2057	1973	1899	1806	1800	1788	1860	1841	1841	2048	2237
2001	PEAK		3082	3080	2962	2832	2493	2300	2361	2404	2372	2689	2933	3278
	ENERGY	2006	2339	2114	2028	1951	1855	1849	1837	1911	1891	1891	2104	2298
2002	PEAK		3163	3160	3040	2905	2558	2360	2422	2467	2434	2760	3009	3363
	ENERGY	2058	2400	2169	2081	2002	1904	1897	1885	1961	1941	1941	2159	2358
2003	PEAK		3246	3244	3120	2982	2626	2423	2486	2532	2498	2832	3089	3452
	ENERGY	2112	2463	2226	2136	2055	1954	1948	1935	2013	1992	1992	2216	2421
2004	PEAK		3324	3322	3195	3054	2689	2481	2546	2593	2558	2901	3163	3535
	ENERGY	2163	2522	2280	2187	2105	2001	1994	1981	2061	2040	2040	2269	2479
2005	PEAK		3400	3398	3268	3124	2751	2538	2604	2653	2617	2967	3236	3616
	ENERGY	2213	2580	2332	2237	2153	2047	2040	2027	2109	2087	2087	2321	2536
2006	PEAK		3477	3474	3342	3194	2813	2595	2663	2712	2675	3034	3308	3697
	ENERGY	2262	2638	2385	2287	2201	2093	2086	2072	2156	2133	2133	2373	2593
2007	PEAK		3545	3542	3407	3257	2868	2646	2715	2765	2728	3093	3373	3770
	ENERGY	2307	2690	2431	2332	2244	2134	2127	2113	2198	2175	2175	2420	2644
2008	PEAK		3611	3609	3471	3318	2921	2695	2766	2817	2779	3151	3436	3840
	ENERGY	2350	2740	2477	2376	2287	2174	2167	2153	2240	2216	2216	2465	2693
2009	PEAK		3679	3676	3536	3380	2976	2746	2818	2870	2831	3210	3501	3912
	ENERGY	2394	2791	2523	2420	2329	2214	2207	2193	2281	2257	2257	2511	2743
2010	PEAK		3748	3745	3602	3443	3032	2797	2870	2924	2884	3270	3566	3985
	ENERGY	2439	2843	2570	2465	2373	2256	2248	2234	2324	2300	2300	2558	2795
2011	PEAK		3816	3813	3668	3506	3087	2848	2923	2977	2936	3330	3631	4058
	ENERGY	2483	2895	2617	2510	2416	2297	2289	2274	2366	2342	2342	2605	2846
2012	PEAK		3868	3865	3717	3553	3129	2887	2962	3017	2976	3375	3680	4113
	ENERGY	2517	2934	2653	2544	2449	2328	2320	2305	2398	2373	2373	2640	2884

Pacificorp Electric Operations - Firm Load - RAMPP II Medium High Forecast

Pacific Division - Washington

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		694	688	595	547	452	491	565	576	532	584	622	693
	ENERGY	427	520	452	412	396	362	383	403	423	417	414	438	505
1992	PEAK		712	706	610	561	463	504	579	591	545	599	638	711
	ENERGY	438	534	464	423	406	371	393	414	434	427	425	449	519
1993	PEAK		728	722	624	574	474	516	593	605	558	613	653	727
	ENERGY	449	546	475	432	416	380	402	423	444	437	435	460	531
1994	PEAK		745	739	639	587	485	528	607	619	571	627	669	744
	ENERGY	459	559	486	442	426	389	412	433	455	448	445	470	543
1995	PEAK		765	759	656	603	498	542	623	636	586	644	686	764
	ENERGY	471	574	499	454	437	399	423	445	467	459	457	483	558
1996	PEAK		789	782	677	622	514	559	642	656	605	664	708	788
	ENERGY	486	592	515	469	451	412	436	459	482	474	471	498	575
1997	PEAK		812	805	696	640	529	575	661	675	622	684	729	811
	ENERGY	500	609	530	482	464	424	449	472	496	488	485	513	592
1998	PEAK		834	827	715	657	543	591	679	693	639	702	748	833
	ENERGY	514	625	544	495	476	435	461	485	509	501	498	526	608
1999	PEAK		860	852	737	677	560	609	700	714	659	724	771	859
	ENERGY	529	645	561	510	491	448	475	500	525	516	514	543	626
2000	PEAK		884	876	757	696	575	626	719	734	677	744	793	883
	ENERGY	544	663	576	525	504	461	488	514	539	531	528	558	644
2001	PEAK		907	899	777	714	590	642	738	753	695	763	813	906
	ENERGY	558	680	591	538	518	473	501	527	553	544	542	572	661
2002	PEAK		929	922	797	732	605	658	757	772	712	782	834	929
	ENERGY	572	697	606	552	531	485	514	540	567	558	555	587	677
2003	PEAK		953	945	817	751	621	675	776	792	730	802	855	952
	ENERGY	587	715	622	566	544	497	527	554	582	572	569	602	694
2004	PEAK		976	968	837	769	636	692	795	811	748	822	876	975
	ENERGY	601	732	637	580	557	509	539	568	596	586	583	616	711
2005	PEAK		998	990	856	787	650	707	813	829	765	840	896	997
	ENERGY	615	749	651	593	570	521	552	580	609	600	596	630	727
2006	PEAK		1023	1014	877	806	666	724	832	850	784	861	917	1022
	ENERGY	630	767	667	607	584	533	565	595	624	614	611	646	745
2007	PEAK		1045	1036	896	823	680	740	851	868	801	880	937	1044
	ENERGY	644	784	682	620	597	545	577	608	638	628	624	660	761
2008	PEAK		1067	1058	915	841	695	756	869	887	818	899	958	1066
	ENERGY	657	801	696	634	609	557	590	621	652	641	638	674	778
2009	PEAK		1090	1081	935	859	710	772	887	906	835	918	978	1089
	ENERGY	671	818	711	647	622	569	602	634	665	655	651	688	794
2010	PEAK		1114	1104	955	877	725	789	906	925	853	937	999	1112
	ENERGY	686	835	726	661	636	581	615	647	680	669	665	703	811
2011	PEAK		1137	1127	975	896	740	805	925	944	871	957	1020	1136
	ENERGY	700	853	742	675	649	593	628	661	694	683	679	718	828
2012	PEAK		1157	1147	992	912	753	820	942	961	887	974	1038	1156
	ENERGY	713	868	755	687	661	604	639	673	706	695	691	731	843

Pacificorp Electric Operations - Firm Load - RAMPP II Medium High Forecast

Pacific Division - Idaho

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		50	46	48	40	34	27	31	31	30	44	43	55
	ENERGY	29	36	34	33	29	25	24	22	24	24	27	31	36
1992	PEAK		51	47	49	41	35	28	32	32	30	45	44	56
	ENERGY	29	37	35	33	29	25	24	23	24	25	28	32	36
1993	PEAK		53	49	51	42	36	29	33	33	31	47	46	58
	ENERGY	30	39	36	35	31	26	25	24	25	26	29	33	38
1994	PEAK		55	51	53	44	38	30	35	35	33	49	48	61
	ENERGY	32	40	38	36	32	27	26	25	26	27	30	35	39
1995	PEAK		58	53	56	46	40	32	37	37	34	52	51	64
	ENERGY	33	42	40	38	34	29	28	26	28	28	32	37	41
1996	PEAK		61	56	59	49	42	33	39	39	36	54	53	68
	ENERGY	35	45	42	40	35	30	29	27	29	30	33	39	44
1997	PEAK		64	58	61	51	43	35	40	40	38	56	55	70
	ENERGY	36	46	43	41	37	32	30	29	30	31	34	40	45
1998	PEAK		66	61	63	53	45	36	42	42	39	59	57	73
	ENERGY	38	48	45	43	38	33	31	30	31	32	36	42	47
1999	PEAK		69	63	66	55	47	38	43	43	41	61	60	76
	ENERGY	40	50	47	45	40	34	33	31	33	34	37	43	49
2000	PEAK		72	66	69	58	49	40	45	45	43	64	63	80
	ENERGY	42	53	49	47	42	36	34	32	34	35	39	45	51
2001	PEAK		75	69	72	60	51	41	47	47	45	67	65	83
	ENERGY	43	55	51	49	43	37	36	34	36	37	41	47	54
2002	PEAK		78	72	75	62	53	43	49	49	46	69	68	86
	ENERGY	45	57	53	51	45	39	37	35	37	38	42	49	56
2003	PEAK		81	74	78	65	55	44	51	51	48	72	71	90
	ENERGY	47	59	55	53	47	40	38	36	39	40	44	51	58
2004	PEAK		84	77	80	67	57	46	53	53	50	74	73	93
	ENERGY	48	61	57	55	49	42	40	38	40	41	45	53	60
2005	PEAK		87	80	83	70	59	48	55	55	52	77	76	96
	ENERGY	50	64	59	57	50	43	41	39	42	42	47	55	62
2006	PEAK		90	83	86	72	61	49	57	57	53	80	78	99
	ENERGY	52	66	61	59	52	45	43	40	43	44	49	57	64
2007	PEAK		93	85	89	74	63	51	59	59	55	83	81	103
	ENERGY	54	68	63	61	54	46	44	42	44	45	50	59	66
2008	PEAK		97	88	92	77	66	53	61	61	57	86	84	106
	ENERGY	55	70	65	63	56	48	46	43	46	47	52	61	69
2009	PEAK		100	92	96	80	68	55	63	63	59	89	87	110
	ENERGY	57	73	68	65	58	50	47	45	48	49	54	63	71
2010	PEAK		104	95	99	83	70	57	65	65	61	92	90	114
	ENERGY	59	75	70	68	60	51	49	46	49	50	56	65	74
2011	PEAK		107	98	102	85	73	59	67	67	63	95	93	118
	ENERGY	62	78	73	70	62	53	51	48	51	52	58	67	76
2012	PEAK		110	101	105	88	75	60	69	69	65	98	96	122
	ENERGY	63	80	75	72	64	55	52	49	53	54	60	69	78

Pacificorp Electric Operations - Firm Load - RAMPP II Medium High Forecast

Pacific Division - Montana

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		159	148	146	132	102	101	102	100	96	122	137	160
	ENERGY	93	118	105	103	93	79	80	79	79	84	86	99	111
1992	PEAK		161	150	148	134	103	102	103	101	97	124	139	162
	ENERGY	94	120	106	105	95	80	81	80	80	85	87	100	113
1993	PEAK		167	155	153	138	107	106	107	104	100	128	143	167
	ENERGY	97	124	109	108	98	83	84	83	83	87	90	103	116
1994	PEAK		171	159	156	142	109	108	109	107	103	131	147	172
	ENERGY	100	127	112	111	100	85	86	85	85	90	92	106	119
1995	PEAK		176	163	161	146	113	112	113	110	106	135	151	176
	ENERGY	103	130	115	114	103	87	88	88	87	92	95	109	123
1996	PEAK		181	168	165	150	116	115	116	113	108	138	156	181
	ENERGY	105	134	119	117	106	90	91	90	90	95	97	112	126
1997	PEAK		186	173	170	154	119	118	119	116	111	142	160	186
	ENERGY	108	138	122	120	109	92	93	92	92	97	100	115	130
1998	PEAK		192	178	175	159	123	122	123	120	115	147	165	192
	ENERGY	112	142	126	124	112	95	96	95	95	100	103	119	134
1999	PEAK		198	184	181	164	127	126	127	124	119	152	171	199
	ENERGY	116	147	130	129	116	99	99	99	99	104	107	123	138
2000	PEAK		206	191	189	171	132	131	132	129	124	158	177	207
	ENERGY	120	153	135	134	121	102	103	103	102	108	111	128	144
2001	PEAK		214	199	196	177	137	136	137	134	128	164	184	215
	ENERGY	125	159	140	139	125	106	107	107	106	112	115	133	149
2002	PEAK		222	206	203	184	142	141	142	139	133	170	191	223
	ENERGY	129	165	146	144	130	110	111	110	110	116	119	138	155
2003	PEAK		231	215	212	192	148	147	148	145	139	177	199	232
	ENERGY	135	171	152	150	135	115	116	115	115	121	124	143	161
2004	PEAK		237	220	217	196	152	150	152	148	142	181	204	238
	ENERGY	138	176	155	154	139	118	119	118	118	124	127	147	165
2005	PEAK		246	228	225	204	157	156	157	154	147	188	211	247
	ENERGY	143	182	161	159	144	122	123	122	122	129	132	152	171
2006	PEAK		253	235	232	210	162	161	162	159	152	194	218	254
	ENERGY	148	188	166	164	148	126	127	126	126	133	136	157	177
2007	PEAK		262	244	240	218	168	166	168	164	157	201	226	263
	ENERGY	153	195	172	170	154	130	132	131	130	137	141	163	183
2008	PEAK		269	250	247	223	173	171	173	169	162	206	232	271
	ENERGY	157	200	177	175	158	134	135	134	134	141	145	167	188
2009	PEAK		278	258	254	230	178	176	178	174	167	213	239	279
	ENERGY	162	206	182	180	163	138	139	138	138	145	149	172	194
2010	PEAK		288	267	263	238	184	182	184	180	173	220	247	289
	ENERGY	168	213	189	186	169	143	144	143	143	151	155	178	201
2011	PEAK		298	277	273	247	191	189	191	187	179	228	257	299
	ENERGY	174	221	196	193	175	148	150	148	148	156	160	185	208
2012	PEAK		306	285	280	254	196	194	196	192	184	235	264	307
	ENERGY	179	227	201	199	179	152	154	152	152	161	165	190	214

Pacificorp Electric Operations - Firm Load - RAMPP II Medium High Forecast

Pacific Division - California

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		145	140	133	137	126	132	147	130	117	122	132	152
	ENERGY	95	109	92	90	89	95	102	105	98	87	84	87	105
1992	PEAK		149	144	137	140	129	136	151	133	120	126	135	156
	ENERGY	98	111	95	92	92	98	104	108	101	90	86	89	108
1993	PEAK		152	147	140	144	132	139	154	136	123	128	138	160
	ENERGY	100	114	97	94	94	100	106	110	103	92	88	91	110
1994	PEAK		155	150	142	146	135	142	157	139	125	131	141	163
	ENERGY	102	116	99	96	96	102	109	112	105	93	90	93	112
1995	PEAK		159	154	146	150	138	145	161	142	128	134	145	167
	ENERGY	104	119	101	98	98	104	111	115	108	96	92	95	115
1996	PEAK		163	158	150	154	142	149	165	146	132	138	149	172
	ENERGY	107	122	104	101	101	107	114	118	111	98	94	97	118
1997	PEAK		167	162	153	158	145	153	169	149	135	141	152	176
	ENERGY	110	125	106	103	103	110	117	121	113	101	97	100	121
1998	PEAK		170	165	156	161	148	155	172	152	137	144	155	179
	ENERGY	112	127	108	105	105	112	119	123	115	102	98	102	123
1999	PEAK		174	169	160	164	152	159	176	156	140	147	159	183
	ENERGY	114	131	111	108	107	114	122	126	118	105	101	104	126
2000	PEAK		178	172	163	168	155	162	180	159	143	150	162	187
	ENERGY	117	133	113	110	110	117	125	129	121	107	103	106	129
2001	PEAK		181	175	167	171	158	166	184	162	146	153	165	191
	ENERGY	119	136	116	112	112	119	127	132	123	109	105	108	131
2002	PEAK		185	179	170	175	161	169	187	165	149	156	168	194
	ENERGY	122	139	118	114	114	121	129	134	125	111	107	110	134
2003	PEAK		189	183	174	179	165	173	192	169	152	160	172	199
	ENERGY	124	142	121	117	117	124	132	137	128	114	109	113	137
2004	PEAK		192	186	177	182	168	176	195	172	155	163	175	203
	ENERGY	127	144	123	119	119	126	135	140	131	116	111	115	139
2005	PEAK		196	190	180	185	171	179	199	175	158	165	178	206
	ENERGY	129	147	125	121	121	129	137	142	133	118	113	117	142
2006	PEAK		199	193	183	188	173	182	202	178	160	168	181	209
	ENERGY	131	149	127	123	123	131	139	145	135	120	115	119	144
2007	PEAK		202	196	186	191	176	185	205	181	163	171	184	213
	ENERGY	133	152	129	125	125	133	142	147	137	122	117	121	147
2008	PEAK		206	200	189	195	180	188	209	184	166	174	188	217
	ENERGY	136	155	131	128	127	135	144	150	140	124	119	123	149
2009	PEAK		210	204	193	199	183	192	213	188	169	178	191	221
	ENERGY	138	158	134	130	130	138	147	153	143	127	122	126	152
2010	PEAK		214	207	197	202	187	196	217	192	173	181	195	225
	ENERGY	141	161	137	133	132	141	150	156	145	129	124	128	155
2011	PEAK		218	211	200	206	190	199	221	195	176	184	199	229
	ENERGY	143	164	139	135	135	143	153	158	148	131	126	130	158
2012	PEAK		221	214	203	209	193	202	224	198	178	187	202	233
	ENERGY	146	166	141	137	137	145	155	161	150	133	128	132	160

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Pacific Division - Wyoming

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		1001	976	972	932	863	970	922	932	932	903	958	1000
	ENERGY	865	921	929	881	873	784	846	832	837	847	839	885	912
1992	PEAK		1026	1000	996	955	884	994	945	955	955	925	982	1025
	ENERGY	886	944	952	903	894	803	867	852	858	868	860	907	934
1993	PEAK		1072	1045	1040	998	923	1038	987	997	998	966	1026	1070
	ENERGY	926	986	994	943	934	839	905	891	896	906	898	947	976
1994	PEAK		1116	1088	1084	1039	962	1082	1028	1039	1039	1006	1068	1115
	ENERGY	964	1027	1036	982	973	874	943	928	933	944	935	986	1016
1995	PEAK		1151	1123	1118	1072	992	1116	1060	1072	1072	1038	1102	1150
	ENERGY	995	1059	1068	1013	1004	901	973	957	963	974	965	1017	1048
1996	PEAK		1189	1159	1154	1107	1024	1152	1095	1106	1107	1072	1138	1187
	ENERGY	1027	1094	1103	1046	1036	930	1004	988	994	1005	996	1051	1082
1997	PEAK		1229	1198	1193	1144	1059	1191	1132	1144	1144	1108	1176	1228
	ENERGY	1062	1131	1140	1082	1071	962	1038	1021	1028	1039	1030	1086	1119
1998	PEAK		1271	1240	1234	1184	1096	1232	1171	1183	1184	1146	1217	1270
	ENERGY	1098	1170	1180	1119	1108	995	1074	1057	1063	1075	1065	1124	1158
1999	PEAK		1321	1288	1282	1229	1138	1280	1216	1229	1230	1191	1264	1319
	ENERGY	1141	1215	1225	1162	1151	1034	1116	1097	1104	1117	1107	1167	1202
2000	PEAK		1370	1336	1330	1275	1180	1327	1261	1275	1275	1235	1311	1368
	ENERGY	1183	1260	1271	1206	1194	1072	1157	1138	1145	1158	1148	1211	1247
2001	PEAK		1421	1386	1380	1323	1224	1377	1308	1322	1323	1281	1360	1419
	ENERGY	1227	1307	1318	1251	1239	1112	1200	1181	1188	1202	1191	1256	1294
2002	PEAK		1472	1436	1430	1371	1269	1427	1356	1370	1371	1328	1409	1471
	ENERGY	1272	1355	1366	1296	1283	1152	1244	1224	1231	1245	1234	1301	1341
2003	PEAK		1523	1485	1478	1417	1312	1476	1402	1417	1418	1373	1457	1521
	ENERGY	1315	1401	1413	1340	1327	1192	1286	1265	1273	1288	1276	1346	1386
2004	PEAK		1572	1533	1526	1463	1355	1523	1447	1463	1464	1417	1505	1570
	ENERGY	1358	1446	1458	1384	1370	1230	1328	1306	1315	1329	1317	1389	1431
2005	PEAK		1620	1580	1573	1508	1396	1570	1492	1508	1509	1461	1551	1618
	ENERGY	1400	1491	1503	1426	1412	1268	1369	1346	1355	1370	1358	1432	1475
2006	PEAK		1673	1631	1624	1557	1442	1621	1541	1557	1558	1508	1601	1671
	ENERGY	1445	1539	1552	1473	1458	1309	1414	1390	1399	1415	1402	1479	1523
2007	PEAK		1724	1681	1674	1605	1485	1670	1587	1604	1605	1554	1650	1722
	ENERGY	1489	1586	1599	1517	1503	1349	1456	1433	1441	1458	1444	1523	1570
2008	PEAK		1772	1728	1721	1650	1527	1717	1632	1649	1650	1598	1696	1770
	ENERGY	1531	1631	1644	1560	1545	1387	1497	1473	1482	1499	1485	1566	1614
2009	PEAK		1820	1774	1767	1694	1568	1763	1676	1694	1694	1641	1742	1818
	ENERGY	1572	1674	1688	1602	1586	1424	1537	1512	1522	1539	1525	1608	1657
2010	PEAK		1868	1822	1814	1739	1610	1810	1720	1739	1740	1685	1788	1866
	ENERGY	1614	1719	1733	1645	1628	1462	1578	1553	1562	1580	1566	1651	1701
2011	PEAK		1919	1872	1864	1787	1654	1860	1767	1786	1787	1731	1837	1917
	ENERGY	1658	1766	1781	1690	1673	1502	1622	1595	1605	1623	1608	1696	1748
2012	PEAK		1969	1920	1911	1833	1696	1908	1813	1832	1833	1775	1884	1966
	ENERGY	1701	1811	1826	1733	1716	1541	1663	1636	1646	1665	1650	1740	1792

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Utah Division - Idaho

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		260	253	251	139	158	348	450	381	285	235	248	259
	ENERGY	209	188	165	170	103	152	264	398	304	206	190	163	191
1992	PEAK		271	255	264	148	163	363	469	404	306	252	268	273
	ENERGY	220	195	173	180	110	155	275	409	322	223	204	180	201
1993	PEAK		287	271	280	160	175	384	494	427	323	269	285	290
	ENERGY	235	209	186	193	120	167	292	430	341	238	218	193	215
1994	PEAK		302	285	295	171	186	403	516	446	339	283	299	305
	ENERGY	248	221	197	204	129	178	307	450	357	251	231	205	227
1995	PEAK		317	299	310	183	197	422	539	467	355	298	314	321
	ENERGY	261	233	209	216	139	189	322	470	374	265	243	217	240
1996	PEAK		335	316	327	196	209	444	566	491	375	316	332	339
	ENERGY	277	248	223	230	150	202	340	494	394	280	258	231	255
1997	PEAK		352	332	343	208	221	465	591	513	392	332	348	356
	ENERGY	291	262	236	243	160	214	357	516	413	295	272	244	269
1998	PEAK		368	347	359	220	233	486	615	535	410	348	364	372
	ENERGY	306	276	254	261	158	237	353	522	421	315	273	262	277
1999	PEAK		391	365	378	250	240	537	668	578	431	386	383	403
	ENERGY	327	296	273	280	173	255	378	554	449	337	294	281	297
2000	PEAK		415	387	401	268	257	567	704	609	457	409	407	428
	ENERGY	348	316	292	299	188	272	402	586	475	358	314	300	317
2001	PEAK		438	409	423	285	273	596	738	640	481	431	429	451
	ENERGY	368	334	309	317	202	289	425	616	501	378	333	317	336
2002	PEAK		458	429	443	300	288	622	769	668	503	452	449	472
	ENERGY	386	351	325	333	215	304	446	643	524	396	350	334	353
2003	PEAK		477	447	462	314	302	647	798	693	524	471	468	492
	ENERGY	403	367	340	348	227	318	466	669	546	413	367	349	369
2004	PEAK		497	465	480	328	316	671	827	719	544	490	487	511
	ENERGY	420	383	355	363	239	331	485	694	567	431	383	364	385
2005	PEAK		513	481	497	341	328	692	852	741	562	506	504	528
	ENERGY	435	397	368	376	249	344	502	716	586	445	397	377	399
2006	PEAK		536	503	519	358	344	721	887	772	587	529	526	551
	ENERGY	455	416	386	394	264	360	525	747	612	466	416	395	418
2007	PEAK		555	521	537	371	358	745	915	797	607	547	544	570
	ENERGY	471	431	400	409	275	374	544	771	632	482	432	410	434
2008	PEAK		571	537	553	384	369	766	940	819	625	564	561	587
	ENERGY	486	444	413	422	285	386	561	793	651	497	446	423	448
2009	PEAK		586	551	568	395	380	785	962	839	641	578	575	602
	ENERGY	499	457	424	434	295	397	576	813	668	510	458	434	460
2010	PEAK		603	572	588	394	403	785	970	850	663	581	596	613
	ENERGY	513	469	430	441	316	397	612	850	695	519	485	442	479
2011	PEAK		619	588	604	407	414	806	995	873	680	597	612	629
	ENERGY	527	482	443	454	327	409	628	872	714	534	498	455	493
2012	PEAK		631	599	616	415	423	821	1013	889	693	609	624	642
	ENERGY	538	492	452	463	334	418	640	888	727	545	508	464	503

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Utah Division - Wyoming

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		320	302	283	272	261	224	241	273	237	278	273	299
	ENERGY	266	301	305	253	265	255	271	240	266	239	261	250	283
1992	PEAK		325	306	287	276	265	227	245	277	240	282	277	304
	ENERGY	269	305	309	257	269	259	275	244	269	242	265	254	287
1993	PEAK		340	320	301	288	277	238	256	290	251	295	290	318
	ENERGY	282	319	323	269	282	271	288	255	282	254	277	266	301
1994	PEAK		354	334	313	300	288	248	267	302	262	307	302	331
	ENERGY	294	332	337	280	293	282	300	266	294	264	289	277	313
1995	PEAK		362	341	321	307	295	254	273	309	268	315	309	339
	ENERGY	301	340	345	286	300	289	307	272	301	271	295	283	321
1996	PEAK		370	349	328	314	302	259	279	316	274	322	316	347
	ENERGY	307	348	353	293	307	296	313	278	307	277	302	290	328
1997	PEAK		380	358	337	323	310	266	287	325	281	330	325	356
	ENERGY	316	357	362	301	315	303	322	285	316	284	310	298	337
1998	PEAK		390	368	346	332	318	273	294	334	289	339	334	366
	ENERGY	324	367	372	309	324	312	331	293	324	292	319	306	346
1999	PEAK		401	378	356	341	327	281	303	343	297	349	343	376
	ENERGY	333	377	382	317	333	320	340	301	333	300	328	314	356
2000	PEAK		412	389	365	350	336	289	311	352	305	358	352	386
	ENERGY	342	388	393	326	342	329	349	310	342	308	337	323	365
2001	PEAK		424	400	376	360	346	297	320	362	314	369	362	397
	ENERGY	352	399	404	335	352	339	359	318	352	317	346	332	376
2002	PEAK		436	411	387	371	356	306	329	373	323	379	373	409
	ENERGY	362	410	416	345	362	348	369	328	362	326	356	342	387
2003	PEAK		448	422	397	380	365	314	338	382	331	389	382	419
	ENERGY	372	421	426	354	371	357	379	336	372	335	365	350	397
2004	PEAK		458	432	406	389	373	321	345	391	339	398	391	429
	ENERGY	380	430	436	362	380	366	388	344	380	342	374	359	406
2005	PEAK		468	441	414	397	381	328	353	400	346	407	400	438
	ENERGY	388	440	445	370	388	374	396	351	388	350	382	366	414
2006	PEAK		478	450	423	406	390	335	360	408	353	415	408	447
	ENERGY	397	449	455	378	396	382	405	359	397	357	390	374	423
2007	PEAK		487	460	432	414	397	341	368	416	361	424	416	456
	ENERGY	405	458	464	386	404	389	413	366	405	364	398	382	432
2008	PEAK		496	468	439	421	404	347	374	424	367	431	424	464
	ENERGY	412	466	472	392	411	396	420	372	412	371	405	388	439
2009	PEAK		504	475	446	428	411	353	380	430	373	438	430	472
	ENERGY	418	474	480	399	418	402	427	378	418	377	411	395	446
2010	PEAK		512	482	453	434	417	358	386	437	378	445	437	479
	ENERGY	425	481	487	405	424	408	433	384	425	382	417	400	453
2011	PEAK		519	489	460	441	423	364	391	444	384	451	443	486
	ENERGY	431	488	494	411	431	415	440	390	431	388	424	406	460
2012	PEAK		527	497	467	447	429	369	397	450	390	458	450	493
	ENERGY	437	495	502	417	437	421	446	396	437	394	430	412	467

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Utah Division - Utah

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		1827	1879	1815	1517	1686	2005	2080	2080	1983	1623	1730	1880
	ENERGY	1423	1478	1443	1443	1247	1325	1404	1539	1514	1416	1356	1368	1529
1992	PEAK		1916	1961	1906	1593	1767	2102	2181	2188	2087	1709	1824	1974
	ENERGY	1494	1549	1514	1515	1310	1387	1471	1608	1593	1493	1428	1444	1606
1993	PEAK		2002	2049	1992	1667	1846	2197	2279	2286	2181	1787	1906	2063
	ENERGY	1563	1620	1584	1585	1371	1451	1539	1681	1666	1562	1494	1511	1679
1994	PEAK		2089	2137	2078	1741	1927	2292	2378	2385	2274	1866	1989	2153
	ENERGY	1632	1692	1654	1655	1433	1516	1607	1755	1739	1631	1561	1578	1753
1995	PEAK		2181	2231	2170	1819	2012	2394	2482	2490	2374	1950	2077	2248
	ENERGY	1705	1768	1728	1729	1498	1584	1679	1833	1817	1704	1631	1649	1832
1996	PEAK		2273	2325	2261	1897	2096	2495	2587	2594	2473	2033	2164	2343
	ENERGY	1779	1843	1803	1803	1563	1653	1751	1912	1894	1778	1701	1720	1910
1997	PEAK		2352	2405	2339	1964	2169	2582	2676	2684	2559	2104	2240	2424
	ENERGY	1841	1908	1866	1866	1619	1711	1813	1979	1961	1840	1762	1781	1977
1998	PEAK		2437	2492	2424	2036	2248	2675	2773	2780	2650	2181	2321	2512
	ENERGY	1909	1979	1941	1940	1667	1785	1860	2035	2023	1913	1814	1851	2043
1999	PEAK		2534	2586	2516	2132	2327	2803	2900	2902	2752	2283	2409	2619
	ENERGY	1987	2060	2020	2019	1736	1858	1937	2119	2105	1991	1889	1927	2126
2000	PEAK		2634	2688	2616	2217	2420	2913	3014	3016	2860	2374	2505	2722
	ENERGY	2067	2142	2101	2100	1807	1933	2016	2204	2190	2071	1965	2004	2212
2001	PEAK		2737	2793	2718	2305	2514	3026	3131	3133	2971	2467	2603	2828
	ENERGY	2149	2227	2184	2183	1880	2010	2097	2291	2277	2153	2044	2084	2299
2002	PEAK		2840	2898	2821	2392	2610	3140	3248	3250	3083	2561	2701	2935
	ENERGY	2231	2312	2267	2266	1953	2086	2178	2379	2364	2235	2123	2163	2387
2003	PEAK		2943	3004	2923	2480	2705	3254	3366	3368	3195	2655	2800	3041
	ENERGY	2313	2397	2351	2349	2026	2163	2259	2467	2451	2317	2202	2243	2475
2004	PEAK		3044	3107	3023	2566	2798	3365	3480	3482	3303	2746	2896	3145
	ENERGY	2393	2480	2432	2430	2097	2238	2338	2553	2536	2397	2279	2321	2560
2005	PEAK		3142	3207	3121	2650	2889	3473	3592	3594	3410	2835	2990	3247
	ENERGY	2472	2561	2511	2510	2167	2311	2415	2637	2619	2476	2354	2397	2644
2006	PEAK		3256	3323	3234	2747	2994	3598	3722	3723	3533	2939	3099	3364
	ENERGY	2563	2654	2603	2602	2248	2396	2505	2734	2715	2567	2441	2485	2741
2007	PEAK		3362	3431	3339	2837	3092	3715	3842	3844	3647	3034	3199	3473
	ENERGY	2647	2741	2688	2687	2322	2475	2588	2824	2805	2651	2522	2567	2831
2008	PEAK		3464	3535	3440	2923	3185	3827	3957	3959	3757	3127	3296	3578
	ENERGY	2728	2825	2771	2769	2394	2551	2668	2910	2890	2732	2600	2645	2917
2009	PEAK		3561	3634	3537	3006	3276	3934	4068	4070	3863	3215	3390	3679
	ENERGY	2805	2905	2849	2848	2463	2623	2744	2993	2973	2809	2674	2721	3000
2010	PEAK		3665	3745	3644	3081	3381	4027	4168	4177	3978	3295	3492	3779
	ENERGY	2887	2989	2926	2925	2548	2689	2845	3096	3069	2886	2765	2795	3093
2011	PEAK		3772	3854	3750	3172	3480	4145	4290	4298	4094	3392	3595	3889
	ENERGY	2972	3077	3012	3012	2624	2768	2929	3188	3160	2971	2847	2878	3185
2012	PEAK		3869	3954	3847	3255	3570	4252	4401	4409	4200	3480	3688	3990
	ENERGY	3050	3157	3091	3090	2693	2841	3006	3271	3242	3049	2922	2953	3268

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Utah Division

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		2405	2433	2349	1927	2104	2576	2770	2734	2503	2137	2251	2438
	ENERGY	1896	1966	1912	1866	1615	1732	1940	2178	2082	1860	1808	1781	2003
1992	PEAK		2510	2521	2458	2017	2194	2691	2893	2869	2632	2244	2369	2550
	ENERGY	1983	2050	1996	1952	1689	1802	2020	2261	2185	1959	1898	1878	2096
1993	PEAK		2628	2639	2573	2116	2297	2817	3028	3002	2754	2351	2481	2670
	ENERGY	2078	2149	2093	2047	1773	1890	2118	2367	2289	2053	1991	1969	2196
1994	PEAK		2744	2755	2687	2213	2400	2942	3159	3133	2874	2457	2590	2788
	ENERGY	2172	2246	2188	2140	1855	1977	2213	2472	2391	2146	2081	2059	2295
1995	PEAK		2859	2871	2800	2309	2502	3068	3293	3264	2996	2562	2700	2906
	ENERGY	2266	2342	2282	2232	1936	2063	2307	2576	2492	2239	2171	2148	2393
1996	PEAK		2977	2990	2916	2407	2607	3197	3430	3400	3121	2670	2812	3027
	ENERGY	2362	2440	2378	2327	2019	2151	2405	2684	2597	2334	2263	2240	2494
1997	PEAK		3082	3096	3019	2495	2699	3312	3552	3520	3231	2767	2912	3135
	ENERGY	2447	2528	2464	2411	2094	2230	2492	2781	2690	2419	2345	2321	2583
1998	PEAK		3194	3208	3129	2588	2798	3434	3681	3648	3348	2869	3018	3249
	ENERGY	2538	2621	2567	2510	2149	2333	2543	2849	2767	2518	2405	2418	2664
1999	PEAK		3327	3329	3250	2723	2895	3621	3872	3823	3479	3019	3135	3399
	ENERGY	2647	2732	2675	2617	2242	2433	2654	2973	2886	2627	2510	2522	2778
2000	PEAK		3462	3464	3383	2835	3013	3769	4030	3978	3621	3142	3263	3537
	ENERGY	2756	2844	2785	2725	2337	2533	2766	3098	3007	2736	2615	2627	2893
2001	PEAK		3599	3602	3518	2949	3134	3919	4190	4136	3766	3268	3394	3677
	ENERGY	2868	2959	2897	2835	2434	2636	2880	3225	3129	2847	2723	2733	3010
2002	PEAK		3735	3738	3651	3063	3254	4068	4347	4291	3908	3393	3523	3816
	ENERGY	2978	3072	3008	2944	2530	2737	2992	3349	3249	2956	2829	2839	3126
2003	PEAK		3869	3873	3783	3175	3373	4214	4503	4444	4049	3516	3651	3953
	ENERGY	3087	3184	3117	3052	2624	2837	3103	3471	3368	3064	2934	2943	3240
2004	PEAK		3999	4004	3910	3283	3488	4356	4654	4593	4186	3635	3774	4086
	ENERGY	3193	3292	3223	3156	2716	2934	3210	3590	3483	3169	3035	3044	3350
2005	PEAK		4124	4129	4033	3387	3599	4492	4798	4736	4318	3749	3893	4214
	ENERGY	3294	3396	3324	3256	2804	3028	3312	3703	3592	3270	3132	3140	3457
2006	PEAK		4271	4277	4177	3510	3729	4654	4970	4905	4473	3884	4033	4364
	ENERGY	3413	3518	3444	3374	2907	3137	3434	3838	3723	3388	3247	3254	3582
2007	PEAK		4405	4411	4309	3622	3847	4801	5125	5058	4614	4006	4160	4501
	ENERGY	3522	3629	3553	3481	3002	3237	3544	3960	3841	3496	3351	3358	3696
2008	PEAK		4532	4539	4434	3728	3960	4939	5272	5203	4748	4122	4281	4631
	ENERGY	3624	3735	3656	3583	3091	3331	3647	4075	3952	3598	3450	3456	3803
2009	PEAK		4652	4660	4552	3828	4067	5071	5411	5341	4876	4232	4395	4754
	ENERGY	3722	3834	3753	3680	3176	3421	3746	4184	4058	3695	3544	3550	3906
2010	PEAK		4778	4799	4685	3910	4200	5169	5523	5463	5018	4320	4525	4869
	ENERGY	3823	3939	3843	3772	3288	3495	3889	4331	4190	3787	3668	3637	4027
2011	PEAK		4909	4931	4814	4020	4317	5313	5676	5614	5158	4440	4650	5004
	ENERGY	3930	4048	3950	3877	3381	3593	3997	4450	4305	3893	3770	3739	4138
2012	PEAK		5026	5049	4929	4118	4421	5441	5810	5747	5282	4547	4761	5123
	ENERGY	4024	4145	4045	3971	3463	3680	4092	4555	4407	3987	3861	3829	4238

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Pacific Division

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		4437	4384	4189	3981	3508	3505	3596	3632	3543	3859	4165	4600
	ENERGY	3063	3516	3250	3090	2992	2782	2867	2866	2943	2924	2915	3169	3449
1992	PEAK		4544	4491	4290	4078	3593	3590	3683	3720	3629	3953	4266	4711
	ENERGY	3137	3602	3329	3164	3065	2849	2937	2935	3014	2995	2986	3246	3533
1993	PEAK		4671	4615	4410	4191	3694	3693	3788	3826	3733	4063	4385	4841
	ENERGY	3228	3705	3426	3257	3154	2932	3022	3021	3102	3082	3073	3340	3634
1994	PEAK		4793	4736	4526	4302	3793	3794	3889	3928	3833	4170	4500	4967
	ENERGY	3316	3805	3520	3346	3241	3012	3106	3104	3186	3167	3157	3431	3732
1995	PEAK		4927	4867	4652	4421	3898	3900	3998	4038	3940	4286	4625	5105
	ENERGY	3410	3911	3619	3440	3332	3096	3193	3191	3276	3255	3246	3528	3837
1996	PEAK		5079	5017	4796	4558	4018	4020	4121	4162	4062	4419	4768	5263
	ENERGY	3515	4032	3731	3546	3435	3192	3292	3289	3377	3356	3346	3637	3955
1997	PEAK		5223	5160	4932	4687	4133	4135	4239	4282	4178	4544	4903	5412
	ENERGY	3616	4147	3838	3649	3534	3284	3386	3384	3474	3453	3443	3741	4069
1998	PEAK		5364	5299	5065	4814	4245	4249	4354	4398	4292	4668	5036	5558
	ENERGY	3716	4261	3944	3749	3632	3374	3480	3477	3570	3548	3538	3844	4180
1999	PEAK		5539	5472	5231	4971	4384	4389	4497	4543	4434	4820	5200	5739
	ENERGY	3839	4401	4075	3874	3753	3485	3595	3592	3688	3666	3655	3972	4318
2000	PEAK		5709	5639	5392	5124	4518	4525	4636	4683	4571	4968	5360	5914
	ENERGY	3958	4538	4202	3995	3870	3594	3707	3704	3802	3780	3769	4095	4452
2001	PEAK		5880	5807	5554	5277	4654	4662	4775	4823	4708	5117	5520	6091
	ENERGY	4079	4675	4331	4117	3988	3703	3820	3817	3918	3895	3884	4220	4587
2002	PEAK		6049	5974	5714	5429	4789	4798	4913	4963	4845	5265	5679	6265
	ENERGY	4198	4811	4458	4238	4106	3811	3933	3929	4033	4010	3998	4344	4721
2003	PEAK		6223	6146	5879	5586	4927	4937	5055	5106	4985	5417	5843	6445
	ENERGY	4321	4951	4588	4362	4226	3922	4047	4043	4150	4127	4115	4471	4858
2004	PEAK		6386	6306	6032	5732	5056	5068	5188	5241	5117	5558	5995	6613
	ENERGY	4435	5082	4710	4478	4338	4026	4155	4151	4260	4236	4225	4589	4986
2005	PEAK		6548	6465	6186	5877	5184	5198	5320	5374	5247	5699	6147	6780
	ENERGY	4550	5212	4832	4593	4450	4130	4262	4257	4369	4346	4333	4708	5114
2006	PEAK		6715	6630	6344	6027	5317	5333	5457	5512	5383	5845	6305	6953
	ENERGY	4668	5347	4958	4714	4567	4237	4374	4369	4483	4459	4447	4830	5246
2007	PEAK		6872	6784	6492	6168	5441	5459	5585	5642	5509	5982	6451	7114
	ENERGY	4779	5474	5077	4826	4676	4338	4478	4473	4590	4565	4553	4945	5371
2008	PEAK		7023	6934	6635	6304	5561	5581	5709	5767	5632	6114	6594	7271
	ENERGY	4887	5596	5191	4935	4782	4435	4579	4573	4693	4668	4655	5056	5491
2009	PEAK		7177	7085	6780	6441	5683	5704	5834	5894	5756	6247	6737	7429
	ENERGY	4995	5720	5307	5045	4888	4533	4681	4675	4797	4772	4759	5168	5612
2010	PEAK		7335	7240	6930	6583	5808	5831	5963	6024	5883	6385	6885	7592
	ENERGY	5107	5847	5426	5158	4998	4634	4785	4779	4904	4878	4865	5284	5737
2011	PEAK		7496	7398	7082	6727	5935	5960	6095	6157	6013	6525	7036	7758
	ENERGY	5220	5977	5547	5273	5109	4737	4892	4885	5013	4987	4974	5401	5864
2012	PEAK		7631	7532	7210	6848	6042	6071	6207	6270	6123	6643	7163	7897
	ENERGY	5318	6087	5651	5372	5205	4825	4984	4977	5106	5080	5067	5502	5972

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Total Company

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		6842	6817	6538	5908	5612	6081	6366	6365	6047	5996	6416	7037
	ENERGY	4959	5483	5162	4956	4607	4514	4807	5043	5025	4784	4723	4950	5452
1992	PEAK		7055	7012	6748	6095	5787	6281	6576	6589	6261	6196	6635	7261
	ENERGY	5120	5652	5325	5117	4754	4652	4957	5196	5200	4953	4884	5124	5629
1993	PEAK		7299	7254	6983	6307	5992	6511	6815	6827	6487	6414	6866	7511
	ENERGY	5307	5854	5519	5303	4927	4822	5140	5388	5391	5135	5063	5309	5830
1994	PEAK		7537	7491	7213	6514	6192	6735	7049	7061	6708	6627	7091	7756
	ENERGY	5489	6051	5708	5486	5096	4989	5318	5575	5577	5313	5238	5490	6027
1995	PEAK		7786	7739	7452	6730	6401	6968	7291	7302	6936	6849	7325	8012
	ENERGY	5675	6253	5901	5672	5269	5159	5500	5767	5768	5494	5417	5676	6230
1996	PEAK		8056	8007	7711	6965	6625	7217	7551	7562	7183	7089	7580	8290
	ENERGY	5877	6472	6108	5873	5455	5343	5696	5974	5974	5690	5609	5877	6449
1997	PEAK		8305	8255	7951	7182	6832	7448	7791	7802	7409	7311	7816	8546
	ENERGY	6063	6675	6302	6060	5628	5513	5878	6165	6164	5872	5788	6063	6652
1998	PEAK		8558	8506	8194	7402	7043	7682	8036	8046	7641	7537	8054	8806
	ENERGY	6254	6882	6511	6259	5781	5707	6023	6326	6337	6067	5943	6263	6845
1999	PEAK		8867	8801	8481	7694	7278	8010	8369	8366	7913	7839	8335	9138
	ENERGY	6485	7134	6750	6491	5995	5918	6249	6565	6574	6292	6165	6494	7096
2000	PEAK		9171	9103	8775	7958	7532	8294	8665	8661	8192	8111	8623	9451
	ENERGY	6715	7382	6987	6720	6207	6127	6474	6802	6809	6516	6385	6722	7345
2001	PEAK		9479	9409	9071	8226	7788	8581	8965	8959	8474	8386	8914	9768
	ENERGY	6947	7634	7227	6952	6422	6339	6700	7042	7047	6742	6607	6953	7597
2002	PEAK		9785	9713	9365	8492	8043	8866	9261	9254	8753	8658	9203	10081
	ENERGY	7177	7884	7466	7182	6635	6549	6925	7278	7282	6966	6827	7183	7846
2003	PEAK		10093	10019	9661	8760	8300	9151	9557	9551	9034	8932	9493	10398
	ENERGY	7408	8135	7705	7413	6850	6760	7150	7514	7517	7191	7049	7413	8097
2004	PEAK		10385	10310	9943	9015	8544	9424	9841	9834	9303	9193	9770	10699
	ENERGY	7628	8374	7933	7634	7055	6961	7365	7741	7743	7406	7260	7633	8336
2005	PEAK		10672	10594	10219	9264	8783	9690	10117	10110	9565	9448	10040	10994
	ENERGY	7843	8608	8156	7850	7255	7157	7575	7961	7962	7615	7466	7848	8570
2006	PEAK		10986	10907	10522	9537	9046	9987	10426	10417	9856	9729	10337	11317
	ENERGY	8081	8865	8402	8088	7474	7374	7807	8207	8206	7847	7694	8085	8828
2007	PEAK		11277	11196	10801	9789	9289	10259	10710	10700	10124	9988	10611	11615
	ENERGY	8301	9103	8629	8308	7678	7575	8022	8433	8430	8062	7904	8303	9066
2008	PEAK		11555	11472	11069	10031	9522	10520	10981	10970	10380	10236	10874	11901
	ENERGY	8511	9331	8847	8518	7873	7766	8226	8648	8645	8266	8105	8513	9294
2009	PEAK		11829	11745	11332	10270	9750	10775	11246	11235	10632	10479	11133	12183
	ENERGY	8717	9554	9060	8724	8064	7954	8427	8858	8855	8467	8302	8718	9518
2010	PEAK		12113	12039	11615	10493	10007	11000	11487	11487	10902	10705	11411	12461
	ENERGY	8930	9786	9269	8929	8286	8129	8675	9110	9094	8666	8533	8920	9763
2011	PEAK		12405	12329	11896	10747	10251	11273	11770	11770	11170	10965	11686	12761
	ENERGY	9150	10024	9497	9150	8490	8329	8889	9336	9318	8880	8744	9140	10002
2012	PEAK		12657	12581	12140	10966	10464	11511	12017	12017	11405	11190	11925	13020
	ENERGY	9342	10232	9696	9343	8668	8505	9076	9532	9513	9067	8928	9331	10210

Pacificorp Electric Operations - Firm Load - RAMPP II Medium Low Forecast

Pacific Division - Oregon

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		2337	2336	2247	2147	1891	1745	1790	1823	1799	2040	2224	2486
	ENERGY	1521	1773	1603	1538	1480	1407	1402	1393	1449	1434	1434	1596	1743
1992	PEAK		2341	2339	2250	2151	1894	1747	1793	1826	1801	2043	2228	2489
	ENERGY	1523	1776	1606	1540	1482	1409	1405	1395	1452	1437	1437	1598	1746
1993	PEAK		2426	2424	2332	2229	1963	1811	1858	1893	1867	2117	2309	2580
	ENERGY	1579	1841	1664	1596	1536	1460	1456	1446	1505	1489	1489	1656	1809
1994	PEAK		2477	2476	2381	2276	2004	1849	1898	1933	1906	2162	2357	2634
	ENERGY	1612	1880	1699	1630	1569	1491	1486	1477	1536	1520	1520	1691	1847
1995	PEAK		2486	2485	2390	2284	2011	1856	1904	1940	1913	2170	2366	2644
	ENERGY	1618	1887	1705	1636	1574	1497	1492	1482	1542	1526	1526	1697	1854
1996	PEAK		2488	2486	2391	2285	2012	1857	1905	1941	1914	2171	2367	2645
	ENERGY	1619	1887	1706	1637	1575	1497	1492	1483	1543	1526	1526	1698	1855
1997	PEAK		2493	2492	2396	2291	2017	1861	1910	1945	1919	2176	2373	2651
	ENERGY	1622	1892	1710	1640	1579	1501	1496	1486	1546	1530	1530	1702	1859
1998	PEAK		2506	2505	2409	2303	2028	1871	1920	1955	1929	2187	2385	2665
	ENERGY	1631	1902	1719	1649	1587	1509	1504	1494	1554	1538	1538	1711	1869
1999	PEAK		2524	2522	2426	2319	2042	1884	1933	1969	1942	2202	2401	2684
	ENERGY	1642	1915	1731	1660	1598	1519	1514	1504	1565	1549	1549	1723	1882
2000	PEAK		2541	2539	2442	2334	2056	1897	1946	1982	1955	2217	2418	2702
	ENERGY	1654	1928	1743	1672	1609	1529	1525	1515	1576	1559	1559	1735	1895
2001	PEAK		2563	2561	2463	2355	2073	1913	1963	1999	1972	2236	2439	2725
	ENERGY	1668	1945	1758	1686	1623	1543	1538	1528	1589	1573	1573	1750	1911
2002	PEAK		2586	2584	2486	2376	2092	1930	1981	2017	1990	2257	2461	2750
	ENERGY	1683	1962	1774	1701	1637	1557	1552	1541	1604	1587	1587	1765	1928
2003	PEAK		2605	2603	2504	2394	2108	1944	1996	2032	2005	2273	2479	2771
	ENERGY	1695	1977	1787	1714	1650	1568	1563	1553	1616	1599	1599	1778	1943
2004	PEAK		2637	2635	2534	2422	2133	1968	2019	2057	2029	2301	2509	2804
	ENERGY	1716	2000	1808	1735	1669	1587	1582	1572	1635	1618	1618	1800	1966
2005	PEAK		2676	2674	2572	2458	2165	1997	2050	2088	2059	2335	2546	2846
	ENERGY	1741	2030	1835	1760	1694	1611	1605	1595	1659	1642	1642	1827	1996
2006	PEAK		2717	2715	2611	2496	2198	2028	2081	2119	2090	2371	2585	2889
	ENERGY	1768	2061	1863	1787	1720	1635	1630	1619	1685	1667	1667	1854	2026
2007	PEAK		2761	2759	2653	2536	2233	2060	2114	2154	2124	2409	2627	2936
	ENERGY	1796	2095	1893	1816	1748	1662	1656	1646	1712	1694	1694	1884	2059
2008	PEAK		2803	2801	2694	2575	2267	2092	2147	2186	2157	2446	2667	2980
	ENERGY	1824	2127	1922	1844	1775	1687	1682	1671	1738	1720	1720	1913	2090
2009	PEAK		2844	2842	2734	2613	2301	2123	2179	2219	2189	2482	2707	3025
	ENERGY	1851	2158	1951	1871	1801	1712	1707	1695	1764	1745	1745	1942	2121
2010	PEAK		2882	2880	2770	2648	2332	2151	2208	2248	2218	2515	2743	3065
	ENERGY	1876	2187	1977	1896	1825	1735	1729	1718	1787	1769	1769	1967	2149
2011	PEAK		2907	2905	2794	2670	2351	2169	2226	2268	2237	2536	2766	3091
	ENERGY	1891	2205	1994	1912	1840	1750	1744	1733	1802	1784	1784	1984	2168
2012	PEAK		2932	2930	2818	2694	2372	2188	2246	2287	2256	2558	2790	3118
	ENERGY	1908	2225	2011	1929	1856	1765	1759	1748	1818	1799	1799	2001	2187

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Pacific Division - Washington

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		683	677	586	538	445	484	556	567	523	575	613	682
	ENERGY	421	512	446	406	390	356	377	397	417	410	408	431	498
1992	PEAK		692	686	593	545	451	490	563	575	530	583	621	691
	ENERGY	426	519	451	411	395	361	382	402	422	416	413	437	504
1993	PEAK		713	707	611	562	464	505	580	592	546	600	640	712
	ENERGY	439	535	465	423	407	372	394	415	435	428	426	450	520
1994	PEAK		728	721	624	573	474	515	592	604	558	612	653	727
	ENERGY	448	546	475	432	415	380	402	423	444	437	435	459	530
1995	PEAK		736	729	631	580	479	521	599	611	564	619	660	735
	ENERGY	453	552	480	437	420	384	406	428	449	442	439	464	536
1996	PEAK		746	740	640	588	486	528	607	620	572	628	669	745
	ENERGY	459	560	487	443	426	389	412	434	455	448	446	471	544
1997	PEAK		757	750	649	596	493	536	616	629	580	637	679	756
	ENERGY	466	568	494	449	432	395	418	440	462	454	452	478	551
1998	PEAK		768	761	658	605	500	544	625	638	588	646	689	767
	ENERGY	473	576	501	456	438	400	424	446	469	461	459	485	559
1999	PEAK		779	772	667	613	507	551	634	647	597	655	698	778
	ENERGY	480	584	508	462	445	406	430	453	475	468	465	492	567
2000	PEAK		788	781	676	621	513	558	642	655	604	664	707	787
	ENERGY	485	591	514	468	450	411	435	458	481	473	471	498	574
2001	PEAK		797	790	683	628	519	564	649	662	611	671	715	796
	ENERGY	491	598	520	473	455	416	440	463	486	479	476	503	581
2002	PEAK		806	799	691	635	525	571	656	669	618	678	723	805
	ENERGY	496	605	526	478	460	420	445	469	492	484	481	509	587
2003	PEAK		815	808	699	642	531	577	663	677	624	686	731	814
	ENERGY	502	611	532	484	465	425	450	474	497	489	487	514	594
2004	PEAK		825	818	708	650	537	585	672	686	632	695	740	825
	ENERGY	508	619	538	490	471	431	456	480	504	496	493	521	601
2005	PEAK		838	830	718	660	545	593	682	696	642	705	751	837
	ENERGY	516	628	546	497	478	437	463	487	511	503	500	529	610
2006	PEAK		849	842	728	669	553	601	691	705	651	715	762	848
	ENERGY	523	637	554	504	485	443	469	494	518	510	507	536	619
2007	PEAK		863	856	740	680	562	611	703	717	661	727	774	862
	ENERGY	532	648	563	513	493	450	477	502	527	518	516	545	629
2008	PEAK		877	869	752	691	571	621	714	728	672	738	786	876
	ENERGY	540	658	572	521	501	457	484	510	535	526	524	553	639
2009	PEAK		890	883	763	701	580	631	725	740	682	749	799	889
	ENERGY	548	668	581	529	508	464	492	518	543	535	532	562	649
2010	PEAK		903	895	774	712	588	640	735	750	692	760	810	902
	ENERGY	556	678	589	536	516	471	499	525	551	542	540	570	658
2011	PEAK		914	906	784	720	595	647	744	759	700	769	820	913
	ENERGY	563	686	596	543	522	477	505	531	558	549	546	577	666
2012	PEAK		925	917	793	729	602	655	753	769	709	779	830	924
	ENERGY	570	694	603	549	528	483	511	538	565	556	553	584	674

Pacificorp Electric Operations - Firm Load - RAMPP II Medium Low Forecast

Pacific Division - Idaho

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		49	44	46	39	33	27	30	30	29	43	42	53
	ENERGY	28	35	33	32	28	24	23	22	23	24	26	30	35
1992	PEAK		49	45	47	39	33	27	31	31	29	44	43	54
	ENERGY	28	36	33	32	28	24	23	22	23	24	27	31	35
1993	PEAK		51	47	49	41	35	28	32	32	30	45	44	56
	ENERGY	29	37	34	33	29	25	24	23	24	25	28	32	36
1994	PEAK		53	48	50	42	36	29	33	33	31	47	46	58
	ENERGY	30	38	36	34	30	26	25	24	25	26	28	33	37
1995	PEAK		53	49	51	42	36	29	33	33	31	47	46	58
	ENERGY	30	39	36	35	31	26	25	24	25	26	29	33	38
1996	PEAK		53	49	51	43	36	29	34	34	32	47	46	59
	ENERGY	31	39	36	35	31	26	25	24	25	26	29	34	38
1997	PEAK		54	50	52	43	37	30	34	34	32	48	47	60
	ENERGY	31	40	37	35	31	27	26	24	26	26	29	34	39
1998	PEAK		56	51	53	44	38	30	35	35	33	49	48	61
	ENERGY	32	41	38	36	32	28	26	25	27	27	30	35	40
1999	PEAK		57	52	55	46	39	31	36	36	34	51	50	63
	ENERGY	33	42	39	37	33	28	27	26	27	28	31	36	41
2000	PEAK		59	54	56	47	40	32	37	37	35	52	51	65
	ENERGY	34	43	40	38	34	29	28	26	28	29	32	37	42
2001	PEAK		60	55	57	48	41	33	38	38	36	53	52	66
	ENERGY	35	44	41	39	35	30	28	27	29	29	33	38	43
2002	PEAK		61	56	59	49	42	34	39	39	36	54	53	68
	ENERGY	35	45	42	40	35	30	29	28	29	30	33	39	44
2003	PEAK		63	57	60	50	43	34	39	39	37	55	54	69
	ENERGY	36	46	42	41	36	31	30	28	30	30	34	39	45
2004	PEAK		64	59	61	51	44	35	40	40	38	57	56	71
	ENERGY	37	47	44	42	37	32	30	29	31	31	35	40	46
2005	PEAK		66	61	63	53	45	36	42	42	39	59	57	73
	ENERGY	38	48	45	43	38	33	31	30	32	32	36	42	47
2006	PEAK		68	62	65	54	46	37	43	43	40	60	59	75
	ENERGY	39	49	46	44	39	34	32	30	32	33	37	43	48
2007	PEAK		70	64	67	56	48	38	44	44	41	62	61	77
	ENERGY	40	51	47	46	40	35	33	31	33	34	38	44	50
2008	PEAK		72	66	69	57	49	39	45	45	43	64	62	79
	ENERGY	41	52	49	47	42	36	34	32	34	35	39	45	51
2009	PEAK		74	68	71	59	50	41	47	47	44	66	64	82
	ENERGY	43	54	50	48	43	37	35	33	35	36	40	47	53
2010	PEAK		76	70	73	61	52	42	48	48	45	68	66	84
	ENERGY	44	56	52	50	44	38	36	34	36	37	41	48	54
2011	PEAK		78	71	74	62	53	43	49	49	46	69	68	86
	ENERGY	45	57	53	51	45	39	37	35	37	38	42	49	55
2012	PEAK		80	73	76	64	54	44	50	50	47	71	69	88
	ENERGY	46	58	54	52	46	40	38	36	38	39	43	50	57

Pacificorp Electric Operations - Firm Load - RAMPP II Medium Low Forecast

Pacific Division - Montana

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		152	141	139	126	97	96	97	95	91	116	131	153
	ENERGY	89	113	100	99	89	76	76	76	76	80	82	94	106
1992	PEAK		156	144	142	129	100	99	100	97	93	119	134	156
	ENERGY	91	115	102	101	91	77	78	77	77	82	84	96	109
1993	PEAK		161	150	147	134	103	102	103	101	97	123	139	162
	ENERGY	94	119	106	104	94	80	81	80	80	84	87	100	112
1994	PEAK		165	153	151	137	106	105	106	103	99	126	142	166
	ENERGY	96	122	108	107	97	82	83	82	82	87	89	102	115
1995	PEAK		167	156	153	139	107	106	107	105	101	128	144	168
	ENERGY	98	124	110	109	98	83	84	83	83	88	90	104	117
1996	PEAK		169	157	155	140	108	107	108	106	102	130	146	170
	ENERGY	99	125	111	110	99	84	85	84	84	89	91	105	118
1997	PEAK		171	159	156	142	109	108	109	107	103	131	147	172
	ENERGY	100	127	112	111	100	85	86	85	85	90	92	106	119
1998	PEAK		174	162	160	145	112	111	112	109	105	134	150	175
	ENERGY	102	129	114	113	102	87	88	87	87	91	94	108	122
1999	PEAK		179	166	164	148	114	113	114	112	107	137	154	179
	ENERGY	104	133	117	116	105	89	90	89	89	94	96	111	125
2000	PEAK		183	170	168	152	117	116	117	115	110	140	158	184
	ENERGY	107	136	120	119	107	91	92	91	91	96	99	114	128
2001	PEAK		187	173	171	155	120	118	120	117	112	143	161	187
	ENERGY	109	138	122	121	109	93	94	93	93	98	100	116	130
2002	PEAK		189	176	173	157	121	120	121	118	114	145	163	190
	ENERGY	110	140	124	123	111	94	95	94	94	99	102	117	132
2003	PEAK		191	178	175	158	122	121	122	120	115	146	164	192
	ENERGY	112	142	125	124	112	95	96	95	95	100	103	119	133
2004	PEAK		195	181	178	162	125	124	125	122	117	149	168	196
	ENERGY	114	145	128	126	114	97	98	97	97	102	105	121	136
2005	PEAK		201	187	184	167	129	127	129	126	121	154	173	202
	ENERGY	117	149	132	130	118	100	101	100	100	105	108	125	140
2006	PEAK		206	191	188	171	132	131	132	129	124	158	177	207
	ENERGY	120	153	135	133	121	102	103	102	102	108	111	128	144
2007	PEAK		211	196	193	175	135	134	135	132	127	162	182	212
	ENERGY	123	157	139	137	124	105	106	105	105	111	114	131	147
2008	PEAK		216	201	198	179	139	137	139	135	130	166	186	217
	ENERGY	126	161	142	140	127	108	109	108	108	113	116	134	151
2009	PEAK		222	206	203	184	142	141	142	139	133	170	191	223
	ENERGY	129	164	145	144	130	110	111	110	110	116	119	138	155
2010	PEAK		227	210	207	188	145	144	145	142	136	173	195	227
	ENERGY	132	168	149	147	133	113	114	113	113	119	122	141	158
2011	PEAK		229	213	210	190	147	145	147	144	138	176	197	230
	ENERGY	134	170	150	149	134	114	115	114	114	120	123	142	160
2012	PEAK		233	217	214	193	149	148	149	146	140	179	201	234
	ENERGY	136	173	153	151	137	116	117	116	116	122	126	145	163

Pacificorp Electric Operations - Firm Load - RAMPP II Medium Low Forecast

Pacific Division - California

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		142	137	130	134	123	129	144	127	114	120	129	149
	ENERGY	93	106	90	88	87	93	99	103	96	85	82	85	103
1992	PEAK		143	138	131	135	124	130	145	128	115	121	130	150
	ENERGY	94	107	91	88	88	94	100	104	97	86	83	85	103
1993	PEAK		146	141	134	138	127	133	148	130	118	123	133	153
	ENERGY	96	109	93	90	90	96	102	106	99	88	84	87	106
1994	PEAK		148	144	136	140	129	136	150	133	120	125	135	156
	ENERGY	98	111	95	92	92	97	104	108	101	89	86	89	107
1995	PEAK		149	145	137	141	130	137	151	134	120	126	136	157
	ENERGY	98	112	95	92	92	98	105	108	101	90	86	89	108
1996	PEAK		150	145	138	142	131	137	152	134	121	127	137	158
	ENERGY	99	112	96	93	93	98	105	109	102	90	87	90	109
1997	PEAK		151	146	139	143	132	138	153	135	122	128	138	159
	ENERGY	99	113	96	93	93	99	106	110	102	91	87	90	109
1998	PEAK		152	148	140	144	133	139	154	136	123	129	139	160
	ENERGY	100	114	97	94	94	100	107	111	103	92	88	91	110
1999	PEAK		154	149	141	145	134	141	156	138	124	130	140	162
	ENERGY	101	115	98	95	95	101	108	112	104	93	89	92	111
2000	PEAK		155	151	143	147	135	142	158	139	125	131	142	164
	ENERGY	102	117	99	96	96	102	109	113	105	94	90	93	113
2001	PEAK		156	152	144	148	136	143	159	140	126	132	143	165
	ENERGY	103	117	100	97	97	103	110	114	106	94	91	93	113
2002	PEAK		157	152	144	148	137	144	159	141	127	133	143	165
	ENERGY	103	118	100	97	97	103	110	114	107	95	91	94	114
2003	PEAK		158	153	145	149	138	144	160	141	127	133	144	166
	ENERGY	104	118	101	98	97	104	111	115	107	95	91	94	114
2004	PEAK		159	154	146	150	139	145	161	142	128	134	145	167
	ENERGY	105	119	101	98	98	104	111	116	108	96	92	95	115
2005	PEAK		161	156	148	152	140	147	163	144	129	136	146	169
	ENERGY	106	120	102	99	99	105	112	117	109	97	93	96	116
2006	PEAK		162	157	149	153	141	148	164	145	131	137	148	171
	ENERGY	107	122	103	100	100	106	114	118	110	98	94	97	117
2007	PEAK		164	159	151	155	143	150	166	147	132	139	149	172
	ENERGY	108	123	105	101	101	108	115	119	111	99	95	98	119
2008	PEAK		166	161	152	157	145	152	168	148	134	140	151	175
	ENERGY	109	124	106	103	102	109	116	120	113	100	96	99	120
2009	PEAK		168	163	155	159	147	154	171	150	136	142	153	177
	ENERGY	111	126	107	104	104	110	118	122	114	101	97	100	122
2010	PEAK		170	165	156	161	148	156	173	152	137	144	155	179
	ENERGY	112	128	109	105	105	112	119	124	115	103	99	102	123
2011	PEAK		171	166	158	162	149	157	174	153	138	145	156	180
	ENERGY	113	128	109	106	106	112	120	124	116	103	99	102	124
2012	PEAK		173	167	159	163	150	158	175	155	139	146	157	182
	ENERGY	114	130	110	107	107	113	121	125	117	104	100	103	125

Pacificorp Electric Operations - Firm Load - RAMPP II Medium Low Forecast

Pacific Division - Wyoming

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		976	952	948	909	841	946	899	908	909	880	934	975
	ENERGY	843	898	906	859	851	764	825	811	816	825	818	863	889
1992	PEAK		988	963	959	919	851	957	909	919	920	890	945	986
	ENERGY	853	909	916	869	861	773	834	821	826	835	828	873	899
1993	PEAK		1028	1003	998	957	886	996	947	957	957	927	984	1027
	ENERGY	888	946	954	905	896	805	869	854	860	870	862	909	936
1994	PEAK		1061	1035	1030	988	914	1028	977	988	988	957	1016	1060
	ENERGY	917	976	985	934	925	831	897	882	887	898	889	938	966
1995	PEAK		1081	1054	1049	1006	931	1047	995	1006	1006	974	1034	1079
	ENERGY	934	994	1003	951	942	846	913	898	904	914	906	955	984
1996	PEAK		1100	1073	1068	1024	948	1066	1013	1024	1024	992	1053	1099
	ENERGY	950	1012	1021	968	959	861	929	914	920	930	922	972	1002
1997	PEAK		1123	1095	1091	1046	968	1088	1034	1045	1046	1013	1075	1122
	ENERGY	970	1033	1042	989	979	879	949	933	939	950	941	993	1023
1998	PEAK		1148	1119	1114	1068	989	1112	1057	1068	1068	1035	1098	1146
	ENERGY	991	1056	1065	1010	1000	898	969	954	960	970	962	1014	1045
1999	PEAK		1173	1144	1139	1092	1011	1136	1080	1091	1092	1057	1122	1171
	ENERGY	1013	1079	1088	1032	1022	918	991	975	981	992	983	1036	1068
2000	PEAK		1197	1167	1162	1115	1032	1160	1102	1114	1115	1079	1146	1196
	ENERGY	1034	1101	1111	1054	1044	937	1011	995	1001	1013	1003	1058	1090
2001	PEAK		1223	1192	1187	1138	1054	1185	1126	1138	1138	1102	1170	1221
	ENERGY	1056	1125	1134	1076	1066	957	1033	1016	1022	1034	1024	1080	1113
2002	PEAK		1249	1218	1213	1163	1076	1210	1150	1163	1163	1126	1196	1248
	ENERGY	1079	1149	1159	1100	1089	978	1055	1038	1045	1056	1047	1104	1137
2003	PEAK		1274	1242	1237	1186	1098	1235	1173	1186	1186	1149	1219	1273
	ENERGY	1101	1172	1182	1121	1110	997	1076	1059	1065	1077	1068	1126	1160
2004	PEAK		1299	1267	1261	1209	1119	1259	1196	1209	1210	1171	1243	1297
	ENERGY	1122	1195	1205	1143	1132	1017	1097	1080	1086	1099	1089	1148	1183
2005	PEAK		1326	1293	1287	1234	1142	1284	1221	1234	1234	1195	1269	1324
	ENERGY	1145	1219	1230	1167	1155	1037	1120	1102	1108	1121	1111	1171	1207
2006	PEAK		1353	1319	1313	1259	1166	1311	1245	1259	1259	1220	1295	1351
	ENERGY	1168	1244	1255	1191	1179	1059	1143	1124	1131	1144	1133	1195	1232
2007	PEAK		1380	1345	1339	1284	1189	1337	1270	1284	1285	1244	1320	1378
	ENERGY	1192	1269	1280	1214	1202	1080	1166	1146	1154	1167	1156	1219	1256
2008	PEAK		1405	1370	1364	1308	1211	1361	1294	1307	1308	1267	1345	1403
	ENERGY	1214	1292	1303	1237	1225	1100	1187	1167	1175	1188	1177	1241	1279
2009	PEAK		1429	1393	1387	1330	1231	1385	1316	1330	1331	1288	1368	1427
	ENERGY	1234	1315	1326	1258	1246	1118	1207	1188	1195	1209	1197	1263	1301
2010	PEAK		1452	1416	1410	1352	1252	1407	1337	1352	1352	1310	1390	1451
	ENERGY	1255	1336	1347	1278	1266	1137	1227	1207	1215	1228	1217	1284	1322
2011	PEAK		1476	1440	1433	1374	1272	1431	1359	1374	1375	1331	1413	1475
	ENERGY	1275	1358	1370	1300	1287	1155	1247	1227	1234	1249	1237	1305	1344
2012	PEAK		1501	1463	1457	1397	1293	1454	1382	1397	1397	1353	1436	1499
	ENERGY	1296	1380	1392	1321	1308	1174	1268	1247	1255	1269	1257	1326	1366

Pacificorp Electric Operations - Firm Load - RAMPP II Medium Low Forecast

Utah Division - Idaho

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		252	246	243	134	152	338	438	371	277	228	241	251
	ENERGY	202	182	159	164	98	146	257	387	295	199	183	157	184
1992	PEAK		250	235	244	133	148	337	437	377	283	232	248	252
	ENERGY	202	178	157	164	97	140	254	381	299	205	187	164	184
1993	PEAK		274	258	267	151	166	367	473	409	309	256	272	276
	ENERGY	223	198	176	182	112	158	278	413	326	226	207	183	204
1994	PEAK		290	273	283	162	177	387	497	430	326	271	287	293
	ENERGY	237	211	188	195	122	169	294	434	343	240	220	195	217
1995	PEAK		295	278	288	166	180	393	505	437	331	276	292	298
	ENERGY	241	215	192	199	125	173	299	440	349	245	224	199	221
1996	PEAK		300	282	293	170	184	400	512	443	337	281	297	303
	ENERGY	246	219	196	203	128	176	304	447	355	249	229	203	226
1997	PEAK		305	287	298	173	188	406	520	450	342	286	302	308
	ENERGY	250	223	200	207	131	180	309	454	361	254	233	207	230
1998	PEAK		310	292	303	177	192	413	528	457	348	291	307	314
	ENERGY	255	229	210	216	122	195	295	445	357	263	225	216	228
1999	PEAK		315	292	303	193	185	440	552	475	349	310	308	325
	ENERGY	260	233	214	220	126	199	300	452	363	268	229	220	233
2000	PEAK		319	296	308	197	188	446	560	481	354	314	312	330
	ENERGY	264	237	218	224	129	202	305	459	368	273	233	224	237
2001	PEAK		323	299	311	199	190	450	565	486	358	318	316	333
	ENERGY	267	240	220	227	131	205	309	463	372	275	236	227	240
2002	PEAK		326	302	314	202	193	454	569	490	361	321	319	336
	ENERGY	269	242	223	229	133	207	312	467	375	278	238	229	242
2003	PEAK		327	304	315	203	194	456	571	492	362	322	320	338
	ENERGY	271	244	224	230	134	208	313	469	377	279	240	230	243
2004	PEAK		330	306	318	205	195	459	575	495	365	324	322	340
	ENERGY	273	245	225	232	135	210	315	472	379	282	242	232	245
2005	PEAK		334	310	322	208	199	465	582	501	370	329	327	345
	ENERGY	277	249	229	235	138	213	320	478	384	286	246	236	249
2006	PEAK		340	316	328	212	203	472	590	508	376	335	332	351
	ENERGY	282	254	233	240	141	217	326	486	391	291	250	240	254
2007	PEAK		345	321	333	216	206	478	598	515	381	340	338	356
	ENERGY	286	258	237	244	145	221	331	493	397	295	255	244	258
2008	PEAK		349	325	337	219	210	484	605	521	386	344	342	361
	ENERGY	290	262	241	248	147	224	336	498	402	299	259	248	262
2009	PEAK		353	328	340	222	212	488	610	526	390	347	345	364
	ENERGY	293	265	244	250	150	227	339	503	405	302	261	251	265
2010	PEAK		357	337	348	212	225	472	599	520	398	338	353	361
	ENERGY	296	266	240	248	164	218	362	523	419	300	277	248	274
2011	PEAK		359	340	351	214	227	476	603	524	401	340	356	364
	ENERGY	298	268	242	250	165	220	365	527	422	302	279	250	276
2012	PEAK		361	341	352	215	228	478	605	526	403	342	358	366
	ENERGY	300	270	243	251	166	221	367	529	424	304	281	251	277

Pacificorp Electric Operations - Firm Load - RAMPP II Medium Low Forecast

Utah Division - Wyoming

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		311	293	276	264	254	218	235	266	230	270	266	291
	ENERGY	258	292	296	246	258	248	263	234	258	232	254	244	276
1992	PEAK		312	294	277	265	254	219	235	267	231	271	267	292
	ENERGY	259	293	297	247	259	249	264	234	259	233	255	244	277
1993	PEAK		327	308	290	278	267	229	246	279	242	284	279	306
	ENERGY	271	307	311	259	271	261	277	245	271	244	267	256	290
1994	PEAK		338	319	299	287	275	237	255	289	250	294	289	316
	ENERGY	281	318	322	267	280	270	286	254	281	252	276	265	299
1995	PEAK		341	322	302	290	278	239	257	292	253	297	292	320
	ENERGY	283	321	325	270	283	273	289	256	283	255	279	267	302
1996	PEAK		345	325	305	293	281	241	260	294	255	299	294	323
	ENERGY	286	324	328	273	286	275	292	259	286	257	281	270	305
1997	PEAK		349	329	309	297	285	245	263	298	258	303	298	327
	ENERGY	290	328	332	276	290	279	296	262	290	261	285	273	309
1998	PEAK		354	334	314	301	289	248	267	303	262	308	303	332
	ENERGY	294	333	337	280	294	283	300	266	294	265	289	277	314
1999	PEAK		360	339	319	305	293	252	271	307	266	313	307	337
	ENERGY	299	338	342	284	298	287	305	270	299	269	293	282	319
2000	PEAK		365	344	323	310	297	255	275	312	270	317	312	342
	ENERGY	303	343	347	289	303	291	309	274	303	273	298	286	323
2001	PEAK		371	349	328	315	302	259	279	317	274	322	316	347
	ENERGY	308	348	353	293	307	296	314	278	308	277	302	290	328
2002	PEAK		377	355	334	320	307	264	284	322	279	327	322	353
	ENERGY	313	354	359	298	312	301	319	283	313	281	307	295	334
2003	PEAK		382	360	338	324	311	267	288	326	282	332	326	358
	ENERGY	317	359	364	302	317	305	323	287	317	285	312	299	338
2004	PEAK		387	365	343	328	315	271	292	330	286	336	330	362
	ENERGY	321	363	368	306	321	309	328	290	321	289	316	303	343
2005	PEAK		391	369	347	332	319	274	295	334	289	340	334	366
	ENERGY	325	368	373	310	325	312	331	294	325	292	319	306	347
2006	PEAK		396	373	351	336	323	277	298	338	293	344	338	371
	ENERGY	329	372	377	313	328	316	335	297	329	296	323	310	351
2007	PEAK		400	377	355	340	326	280	302	342	296	348	342	375
	ENERGY	332	376	381	317	332	320	339	301	332	299	327	313	355
2008	PEAK		404	381	358	343	329	283	304	345	299	351	345	378
	ENERGY	335	379	384	319	335	322	342	303	335	302	329	316	358
2009	PEAK		406	383	360	345	331	285	306	347	301	353	347	381
	ENERGY	337	382	387	322	337	325	344	305	337	304	332	318	360
2010	PEAK		409	385	362	347	333	286	308	349	302	355	349	383
	ENERGY	339	384	389	323	339	326	346	307	339	305	334	320	362
2011	PEAK		411	388	364	349	335	288	310	351	304	357	351	385
	ENERGY	341	386	391	325	341	328	348	309	341	307	336	322	364
2012	PEAK		413	390	366	351	337	290	312	353	306	359	353	387
	ENERGY	343	389	394	327	343	330	350	310	343	309	337	324	366

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Utah Division - Utah

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		1777	1827	1765	1474	1640	1949	2023	2023	1928	1577	1682	1827
	ENERGY	1383	1437	1402	1402	1211	1288	1364	1496	1471	1376	1317	1329	1487
1992	PEAK		1802	1844	1793	1496	1662	1976	2051	2058	1964	1606	1715	1857
	ENERGY	1403	1456	1422	1423	1229	1302	1381	1511	1497	1402	1341	1356	1509
1993	PEAK		1879	1923	1869	1562	1732	2061	2139	2146	2047	1675	1788	1936
	ENERGY	1465	1519	1484	1485	1284	1359	1442	1576	1561	1464	1400	1415	1574
1994	PEAK		1932	1977	1923	1607	1782	2120	2199	2207	2105	1724	1839	1991
	ENERGY	1507	1563	1528	1528	1322	1399	1484	1622	1607	1506	1441	1456	1620
1995	PEAK		1962	2008	1953	1633	1810	2153	2234	2241	2137	1751	1868	2022
	ENERGY	1531	1588	1552	1552	1343	1421	1507	1647	1632	1530	1464	1480	1646
1996	PEAK		1992	2038	1982	1658	1837	2186	2267	2275	2169	1778	1896	2053
	ENERGY	1555	1612	1576	1576	1364	1443	1531	1672	1657	1554	1487	1503	1671
1997	PEAK		2019	2066	2009	1681	1862	2216	2298	2306	2199	1803	1922	2081
	ENERGY	1576	1634	1598	1598	1383	1464	1552	1696	1680	1575	1507	1524	1694
1998	PEAK		2051	2098	2041	1708	1891	2250	2334	2342	2233	1832	1953	2114
	ENERGY	1602	1661	1629	1629	1394	1498	1557	1707	1697	1606	1519	1553	1715
1999	PEAK		2084	2127	2069	1749	1912	2308	2389	2390	2265	1875	1980	2155
	ENERGY	1629	1689	1657	1656	1418	1524	1584	1736	1726	1633	1545	1579	1744
2000	PEAK		2117	2161	2103	1778	1943	2345	2427	2428	2301	1906	2012	2189
	ENERGY	1656	1717	1684	1683	1441	1549	1610	1764	1754	1660	1570	1605	1772
2001	PEAK		2154	2199	2139	1809	1977	2385	2469	2470	2341	1939	2047	2227
	ENERGY	1685	1747	1713	1713	1467	1576	1639	1795	1785	1689	1598	1634	1803
2002	PEAK		2195	2240	2179	1843	2014	2430	2515	2516	2385	1976	2086	2269
	ENERGY	1717	1780	1746	1745	1496	1606	1671	1830	1819	1721	1629	1665	1838
2003	PEAK		2236	2282	2221	1879	2052	2476	2562	2563	2430	2014	2125	2312
	ENERGY	1750	1815	1780	1779	1526	1637	1703	1865	1854	1754	1661	1697	1873
2004	PEAK		2281	2328	2265	1917	2094	2525	2613	2615	2478	2054	2168	2358
	ENERGY	1786	1852	1816	1815	1557	1670	1739	1904	1892	1790	1695	1732	1912
2005	PEAK		2332	2380	2316	1960	2141	2581	2671	2672	2533	2100	2217	2410
	ENERGY	1826	1893	1857	1856	1593	1708	1778	1947	1935	1830	1734	1771	1955
2006	PEAK		2391	2440	2374	2010	2195	2646	2738	2739	2597	2154	2273	2471
	ENERGY	1873	1942	1905	1904	1635	1752	1825	1997	1985	1877	1779	1817	2005
2007	PEAK		2448	2499	2431	2059	2248	2709	2803	2804	2659	2206	2328	2530
	ENERGY	1919	1989	1951	1950	1675	1795	1870	2046	2033	1923	1823	1861	2054
2008	PEAK		2502	2553	2484	2105	2297	2768	2864	2865	2717	2254	2379	2586
	ENERGY	1962	2033	1994	1993	1713	1835	1912	2091	2078	1966	1864	1902	2099
2009	PEAK		2551	2604	2534	2147	2343	2822	2920	2922	2771	2299	2426	2637
	ENERGY	2001	2074	2034	2033	1749	1872	1951	2134	2120	2005	1902	1941	2141
2010	PEAK		2601	2660	2587	2176	2399	2856	2960	2967	2828	2331	2478	2681
	ENERGY	2040	2113	2068	2068	1795	1897	2009	2191	2171	2039	1952	1973	2189
2011	PEAK		2649	2708	2635	2217	2443	2908	3014	3021	2880	2374	2523	2730
	ENERGY	2078	2152	2106	2106	1829	1932	2047	2232	2212	2077	1989	2010	2229
2012	PEAK		2697	2757	2682	2258	2488	2961	3068	3076	2932	2417	2569	2780
	ENERGY	2116	2192	2145	2145	1863	1968	2084	2272	2252	2115	2025	2047	2270

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Utah Division

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		2339	2366	2284	1871	2045	2505	2694	2659	2434	2076	2188	2370
	ENERGY	1842	1910	1857	1813	1567	1682	1885	2118	2024	1807	1755	1729	1946
1992	PEAK		2363	2374	2314	1894	2063	2530	2723	2701	2477	2109	2230	2400
	ENERGY	1863	1928	1877	1834	1585	1692	1899	2127	2056	1840	1784	1764	1970
1993	PEAK		2478	2489	2426	1990	2164	2656	2857	2833	2597	2215	2339	2517
	ENERGY	1958	2025	1971	1927	1666	1779	1996	2235	2159	1934	1874	1853	2069
1994	PEAK		2559	2569	2505	2056	2233	2742	2950	2924	2680	2289	2415	2599
	ENERGY	2024	2092	2037	1991	1723	1839	2064	2310	2231	1998	1938	1916	2137
1995	PEAK		2597	2607	2543	2089	2268	2784	2995	2968	2720	2324	2452	2639
	ENERGY	2055	2124	2069	2022	1751	1868	2095	2345	2265	2029	1968	1946	2170
1996	PEAK		2635	2645	2580	2120	2301	2825	3038	3011	2760	2359	2488	2677
	ENERGY	2085	2156	2099	2052	1777	1896	2126	2379	2299	2060	1997	1975	2202
1997	PEAK		2672	2683	2616	2151	2334	2865	3081	3053	2798	2392	2523	2715
	ENERGY	2116	2187	2130	2082	1804	1923	2157	2413	2331	2090	2026	2004	2234
1998	PEAK		2714	2725	2657	2187	2371	2910	3129	3101	2842	2431	2562	2758
	ENERGY	2150	2222	2176	2125	1810	1975	2151	2417	2346	2133	2032	2047	2256
1999	PEAK		2759	2757	2692	2248	2390	2999	3213	3173	2879	2498	2594	2817
	ENERGY	2186	2260	2213	2161	1842	2009	2188	2457	2386	2169	2067	2081	2294
2000	PEAK		2802	2801	2734	2284	2429	3046	3263	3222	2925	2538	2636	2862
	ENERGY	2221	2296	2249	2196	1873	2041	2223	2496	2424	2204	2101	2115	2331
2001	PEAK		2848	2847	2779	2323	2470	3094	3313	3273	2972	2580	2679	2908
	ENERGY	2258	2334	2286	2232	1905	2076	2260	2535	2463	2240	2137	2150	2370
2002	PEAK		2898	2897	2828	2364	2514	3147	3369	3328	3024	2625	2726	2959
	ENERGY	2298	2376	2327	2272	1941	2113	2300	2578	2506	2279	2175	2189	2413
2003	PEAK		2946	2946	2875	2406	2558	3198	3422	3382	3074	2668	2771	3008
	ENERGY	2337	2416	2367	2311	1976	2149	2339	2620	2547	2318	2212	2226	2454
2004	PEAK		2998	2999	2926	2450	2605	3254	3481	3441	3129	2716	2821	3062
	ENERGY	2379	2460	2410	2353	2013	2188	2381	2665	2592	2359	2253	2267	2499
2005	PEAK		3058	3059	2985	2500	2659	3319	3548	3508	3192	2770	2877	3123
	ENERGY	2427	2509	2458	2401	2056	2233	2429	2717	2643	2407	2299	2313	2549
2006	PEAK		3127	3129	3053	2558	2721	3394	3627	3587	3265	2833	2943	3194
	ENERGY	2483	2567	2515	2457	2105	2284	2485	2779	2703	2463	2353	2367	2609
2007	PEAK		3194	3196	3119	2614	2782	3467	3704	3662	3336	2894	3007	3262
	ENERGY	2536	2622	2569	2510	2152	2334	2539	2838	2761	2516	2404	2418	2665
2008	PEAK		3256	3259	3180	2666	2837	3534	3774	3732	3401	2950	3065	3325
	ENERGY	2586	2674	2619	2560	2196	2380	2588	2892	2814	2565	2452	2466	2718
2009	PEAK		3312	3315	3235	2714	2888	3595	3838	3796	3461	3001	3118	3383
	ENERGY	2631	2720	2665	2605	2235	2422	2633	2941	2862	2610	2495	2509	2765
2010	PEAK		3366	3382	3298	2736	2957	3614	3866	3836	3528	3024	3180	3425
	ENERGY	2675	2765	2697	2640	2297	2442	2718	3022	2931	2644	2564	2541	2826
2011	PEAK		3418	3435	3350	2780	3005	3671	3925	3895	3584	3071	3230	3478
	ENERGY	2716	2808	2739	2682	2334	2481	2759	3068	2976	2686	2604	2581	2870
2012	PEAK		3470	3488	3401	2824	3052	3727	3984	3954	3639	3118	3279	3532
	ENERGY	2758	2851	2781	2723	2371	2520	2801	3112	3020	2727	2644	2622	2914

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Pacific Division

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		4339	4287	4096	3893	3430	3427	3516	3552	3465	3774	4073	4498
	ENERGY	2995	3438	3177	3020	2925	2720	2803	2802	2877	2858	2850	3099	3373
1992	PEAK		4368	4316	4123	3918	3453	3450	3541	3576	3489	3799	4100	4528
	ENERGY	3016	3462	3200	3042	2946	2738	2823	2822	2898	2879	2870	3120	3396
1993	PEAK		4525	4471	4272	4060	3578	3575	3668	3705	3615	3936	4248	4690
	ENERGY	3125	3587	3316	3152	3053	2838	2925	2924	3003	2983	2975	3234	3519
1994	PEAK		4632	4577	4373	4156	3663	3662	3756	3794	3702	4029	4349	4801
	ENERGY	3201	3674	3397	3229	3128	2907	2997	2995	3076	3056	3047	3312	3604
1995	PEAK		4673	4616	4411	4192	3695	3696	3790	3828	3735	4065	4386	4842
	ENERGY	3231	3707	3429	3259	3157	2934	3025	3023	3104	3085	3076	3343	3637
1996	PEAK		4706	4649	4442	4222	3721	3725	3819	3858	3764	4094	4418	4876
	ENERGY	3257	3736	3456	3285	3182	2957	3049	3048	3129	3110	3101	3369	3665
1997	PEAK		4750	4692	4483	4260	3756	3762	3857	3895	3801	4132	4458	4920
	ENERGY	3289	3772	3491	3318	3214	2986	3080	3079	3161	3141	3132	3403	3701
1998	PEAK		4804	4745	4534	4309	3798	3807	3902	3941	3846	4179	4509	4975
	ENERGY	3329	3817	3534	3358	3254	3022	3118	3116	3199	3180	3170	3444	3745
1999	PEAK		4865	4805	4592	4363	3847	3857	3953	3993	3896	4233	4566	5037
	ENERGY	3373	3867	3581	3403	3297	3061	3160	3158	3241	3222	3213	3489	3794
2000	PEAK		4924	4863	4647	4415	3893	3905	4002	4042	3944	4284	4621	5097
	ENERGY	3416	3916	3627	3447	3340	3100	3200	3198	3282	3263	3254	3534	3841
2001	PEAK		4986	4923	4706	4471	3943	3956	4053	4094	3995	4338	4679	5161
	ENERGY	3461	3967	3675	3493	3384	3141	3243	3241	3326	3307	3297	3580	3892
2002	PEAK		5049	4986	4766	4528	3993	4009	4106	4147	4047	4393	4739	5226
	ENERGY	3507	4019	3724	3539	3430	3182	3286	3284	3370	3351	3341	3628	3943
2003	PEAK		5106	5042	4820	4579	4039	4056	4154	4195	4095	4443	4792	5284
	ENERGY	3549	4066	3769	3582	3471	3220	3326	3323	3410	3391	3381	3671	3989
2004	PEAK		5179	5114	4889	4645	4097	4115	4214	4256	4154	4507	4861	5359
	ENERGY	3601	4125	3825	3635	3522	3267	3375	3372	3460	3441	3431	3725	4047
2005	PEAK		5267	5200	4972	4723	4166	4185	4285	4328	4224	4583	4943	5450
	ENERGY	3663	4196	3891	3697	3583	3323	3433	3430	3519	3500	3490	3789	4116
2006	PEAK		5354	5286	5055	4802	4235	4256	4356	4400	4295	4660	5025	5540
	ENERGY	3725	4266	3957	3760	3644	3379	3491	3488	3579	3559	3549	3853	4186
2007	PEAK		5449	5379	5144	4886	4310	4331	4433	4478	4371	4742	5113	5638
	ENERGY	3791	4342	4027	3827	3709	3439	3553	3549	3642	3623	3612	3922	4260
2008	PEAK		5539	5467	5229	4967	4381	4402	4506	4551	4443	4820	5198	5730
	ENERGY	3854	4414	4094	3891	3770	3496	3612	3608	3702	3683	3672	3987	4330
2009	PEAK		5628	5555	5313	5047	4451	4473	4578	4624	4514	4897	5281	5823
	ENERGY	3916	4485	4160	3954	3831	3552	3670	3666	3762	3742	3732	4051	4400
2010	PEAK		5711	5637	5392	5121	4517	4539	4646	4693	4581	4970	5359	5909
	ENERGY	3974	4552	4222	4013	3888	3605	3724	3721	3818	3798	3787	4111	4466
2011	PEAK		5775	5700	5452	5179	4568	4592	4699	4747	4633	5026	5420	5975
	ENERGY	4021	4604	4272	4060	3934	3647	3768	3764	3862	3842	3831	4159	4517
2012	PEAK		5844	5767	5517	5240	4621	4647	4755	4803	4689	5085	5483	6045
	ENERGY	4070	4660	4324	4109	3982	3691	3814	3810	3909	3889	3878	4210	4571

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Total Company

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		6677	6653	6379	5763	5475	5932	6211	6210	5899	5849	6261	6867
	ENERGY	4837	5348	5034	4833	4492	4401	4688	4920	4901	4665	4606	4827	5318
1992	PEAK		6731	6690	6437	5813	5516	5981	6264	6277	5966	5908	6330	6928
	ENERGY	4879	5390	5076	4876	4531	4431	4722	4949	4953	4719	4654	4884	5367
1993	PEAK		7004	6960	6698	6050	5741	6231	6526	6538	6212	6151	6587	7208
	ENERGY	5083	5612	5287	5079	4719	4617	4921	5159	5162	4917	4849	5087	5588
1994	PEAK		7191	7146	6878	6213	5896	6404	6707	6718	6381	6318	6764	7400
	ENERGY	5225	5766	5434	5220	4851	4746	5060	5305	5307	5055	4985	5228	5741
1995	PEAK		7270	7224	6954	6281	5963	6480	6785	6796	6456	6389	6838	7480
	ENERGY	5286	5832	5497	5281	4908	4801	5120	5368	5370	5114	5044	5289	5807
1996	PEAK		7341	7295	7022	6342	6022	6550	6858	6869	6524	6453	6905	7553
	ENERGY	5342	5892	5556	5337	4960	4852	5176	5427	5428	5170	5098	5344	5867
1997	PEAK		7422	7374	7099	6411	6089	6627	6937	6948	6599	6524	6981	7635
	ENERGY	5405	5959	5621	5400	5018	4909	5237	5491	5492	5231	5158	5406	5935
1998	PEAK		7518	7470	7191	6495	6169	6717	7031	7042	6688	6610	7071	7733
	ENERGY	5479	6039	5710	5483	5064	4997	5269	5533	5545	5312	5203	5490	6001
1999	PEAK		7624	7562	7283	6611	6237	6856	7166	7165	6775	6731	7160	7854
	ENERGY	5559	6127	5794	5564	5139	5070	5347	5615	5627	5391	5280	5571	6088
2000	PEAK		7726	7664	7382	6700	6322	6951	7265	7264	6869	6822	7257	7959
	ENERGY	5637	6212	5876	5643	5212	5141	5423	5694	5706	5467	5355	5649	6173
2001	PEAK		7834	7771	7485	6794	6412	7051	7367	7367	6967	6918	7358	8069
	ENERGY	5719	6301	5962	5725	5290	5216	5503	5776	5789	5547	5433	5731	6262
2002	PEAK		7947	7882	7593	6892	6507	7156	7475	7475	7071	7018	7464	8184
	ENERGY	5805	6395	6052	5812	5371	5295	5586	5862	5876	5630	5516	5817	6355
2003	PEAK		8052	7988	7695	6985	6597	7255	7576	7578	7169	7112	7563	8292
	ENERGY	5886	6482	6136	5893	5447	5369	5665	5943	5957	5709	5594	5897	6443
2004	PEAK		8177	8112	7815	7094	6702	7370	7694	7697	7283	7223	7681	8421
	ENERGY	5980	6585	6235	5988	5535	5456	5756	6037	6052	5801	5684	5992	6546
2005	PEAK		8325	8258	7957	7223	6825	7504	7833	7836	7416	7353	7820	8572
	ENERGY	6090	6705	6349	6098	5638	5556	5862	6147	6163	5907	5789	6102	6666
2006	PEAK		8482	8415	8108	7360	6957	7650	7984	7987	7560	7493	7968	8734
	ENERGY	6208	6833	6472	6217	5748	5664	5976	6267	6282	6022	5902	6220	6794
2007	PEAK		8643	8575	8263	7501	7091	7798	8136	8140	7707	7636	8120	8900
	ENERGY	6328	6964	6596	6338	5861	5773	6092	6387	6403	6139	6017	6340	6925
2008	PEAK		8794	8726	8409	7633	7218	7937	8280	8284	7844	7770	8263	9056
	ENERGY	6440	7087	6713	6451	5966	5876	6200	6500	6516	6248	6124	6453	7048
2009	PEAK		8939	8870	8548	7760	7339	8068	8416	8420	7975	7898	8400	9205
	ENERGY	6547	7205	6825	6559	6067	5974	6303	6607	6624	6352	6227	6560	7166
2010	PEAK		9077	9020	8690	7857	7474	8153	8512	8529	8109	7993	8540	9333
	ENERGY	6649	7317	6919	6652	6186	6047	6442	6743	6748	6442	6351	6652	7291
2011	PEAK		9194	9136	8802	7959	7572	8263	8624	8642	8217	8097	8650	9453
	ENERGY	6737	7412	7011	6741	6268	6128	6527	6832	6838	6528	6436	6741	7387
2012	PEAK		9314	9255	8918	8064	7673	8375	8739	8757	8328	8204	8763	9576
	ENERGY	6828	7511	7105	6833	6353	6211	6614	6922	6929	6616	6522	6831	7486

Pacificorp Electric Operations - Firm Load - RAMPP II Low Forecast

Pacific Division - Oregon

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		2318	2316	2228	2129	1875	1730	1775	1808	1783	2022	2205	2464
	ENERGY	1508	1758	1589	1525	1467	1395	1390	1381	1437	1422	1422	1582	1728
1992	PEAK		2298	2296	2209	2111	1859	1715	1760	1793	1768	2005	2187	2444
	ENERGY	1495	1744	1576	1512	1455	1383	1379	1370	1425	1410	1410	1569	1714
1993	PEAK		2335	2333	2244	2145	1889	1743	1788	1821	1797	2037	2222	2483
	ENERGY	1519	1772	1601	1536	1478	1405	1401	1392	1448	1433	1433	1594	1741
1994	PEAK		2348	2347	2257	2157	1900	1753	1799	1832	1807	2049	2235	2497
	ENERGY	1528	1782	1611	1545	1487	1414	1409	1400	1456	1441	1441	1603	1751
1995	PEAK		2334	2332	2243	2144	1888	1742	1788	1821	1796	2037	2221	2482
	ENERGY	1519	1771	1601	1535	1478	1405	1400	1391	1447	1432	1432	1593	1740
1996	PEAK		2316	2314	2226	2127	1873	1728	1774	1806	1782	2020	2203	2462
	ENERGY	1507	1757	1588	1523	1466	1394	1389	1380	1436	1421	1421	1581	1727
1997	PEAK		2301	2299	2211	2113	1861	1717	1762	1795	1770	2007	2189	2446
	ENERGY	1497	1745	1578	1513	1457	1385	1380	1371	1427	1412	1412	1570	1716
1998	PEAK		2292	2290	2203	2105	1854	1710	1755	1788	1763	2000	2180	2437
	ENERGY	1491	1739	1572	1508	1451	1379	1375	1366	1421	1406	1406	1564	1709
1999	PEAK		2286	2284	2197	2100	1849	1706	1751	1783	1759	1995	2175	2431
	ENERGY	1487	1734	1568	1504	1447	1376	1371	1362	1417	1403	1403	1560	1705
2000	PEAK		2279	2278	2191	2094	1844	1701	1746	1778	1754	1989	2169	2424
	ENERGY	1483	1729	1563	1500	1443	1372	1368	1359	1414	1399	1399	1556	1700
2001	PEAK		2278	2276	2189	2093	1843	1700	1745	1777	1753	1988	2167	2422
	ENERGY	1482	1728	1562	1499	1442	1371	1367	1358	1413	1398	1398	1555	1699
2002	PEAK		2278	2276	2189	2092	1842	1700	1744	1777	1753	1987	2167	2422
	ENERGY	1482	1728	1562	1498	1442	1371	1366	1358	1412	1398	1398	1555	1698
2003	PEAK		2274	2272	2185	2089	1839	1697	1741	1774	1750	1984	2163	2418
	ENERGY	1479	1725	1559	1496	1440	1369	1364	1355	1410	1395	1395	1552	1695
2004	PEAK		2275	2274	2187	2090	1841	1698	1743	1775	1751	1985	2165	2420
	ENERGY	1481	1726	1561	1497	1441	1370	1365	1356	1411	1396	1396	1553	1697
2005	PEAK		2284	2282	2195	2098	1848	1705	1749	1782	1757	1993	2173	2429
	ENERGY	1486	1733	1566	1502	1446	1375	1370	1361	1416	1401	1401	1559	1703
2006	PEAK		2291	2290	2202	2105	1854	1710	1755	1787	1763	1999	2180	2436
	ENERGY	1491	1738	1571	1507	1451	1379	1375	1366	1421	1406	1406	1564	1709
2007	PEAK		2304	2302	2214	2116	1864	1719	1764	1797	1773	2010	2192	2450
	ENERGY	1499	1748	1580	1515	1459	1387	1382	1373	1429	1414	1414	1572	1718
2008	PEAK		2316	2315	2226	2128	1874	1729	1774	1807	1782	2021	2204	2463
	ENERGY	1507	1757	1589	1524	1466	1394	1390	1381	1436	1421	1421	1581	1727
2009	PEAK		2330	2328	2240	2141	1885	1739	1785	1818	1793	2033	2217	2478
	ENERGY	1516	1768	1598	1533	1475	1403	1398	1389	1445	1430	1430	1591	1738
2010	PEAK		2342	2340	2251	2152	1895	1748	1794	1827	1802	2044	2228	2490
	ENERGY	1524	1777	1606	1541	1483	1410	1405	1396	1452	1437	1437	1599	1746
2011	PEAK		2345	2343	2254	2154	1897	1750	1796	1829	1804	2046	2231	2494
	ENERGY	1526	1779	1608	1543	1485	1411	1407	1398	1454	1439	1439	1601	1749
2012	PEAK		2350	2348	2259	2159	1901	1754	1800	1833	1808	2051	2236	2499
	ENERGY	1529	1783	1612	1546	1488	1415	1410	1401	1457	1442	1442	1604	1752

Pacificorp Electric Operations - Firm Load - RAMPP II Low Forecast

Pacific Division - Washington

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		680	674	583	536	443	481	553	565	521	572	610	679
	ENERGY	419	510	443	404	388	355	375	395	415	408	406	429	495
1992	PEAK		684	678	586	539	445	484	557	568	524	576	614	683
	ENERGY	421	513	446	406	391	357	378	398	417	411	409	432	498
1993	PEAK		694	688	595	547	452	492	565	576	532	584	623	693
	ENERGY	427	521	453	412	396	362	383	403	424	417	415	438	506
1994	PEAK		703	697	602	554	457	498	572	584	538	592	630	702
	ENERGY	433	527	458	417	401	367	388	409	429	422	420	444	512
1995	PEAK		705	699	605	556	459	500	574	586	541	594	633	705
	ENERGY	434	529	460	419	403	368	390	410	431	424	421	445	514
1996	PEAK		710	704	608	559	462	503	578	589	544	597	637	709
	ENERGY	437	532	463	421	405	370	392	413	433	426	424	448	517
1997	PEAK		714	708	612	562	465	506	581	593	547	601	640	713
	ENERGY	440	535	466	424	408	372	394	415	436	429	426	451	520
1998	PEAK		718	712	615	566	467	508	584	596	550	604	644	717
	ENERGY	442	538	468	426	410	374	397	417	438	431	429	453	523
1999	PEAK		721	715	618	568	469	511	587	599	553	607	647	720
	ENERGY	444	541	470	428	412	376	398	419	440	433	431	455	525
2000	PEAK		723	717	620	570	471	512	589	601	554	609	649	722
	ENERGY	445	542	472	429	413	377	399	420	441	434	432	456	527
2001	PEAK		724	717	620	570	471	513	589	601	555	609	649	723
	ENERGY	446	543	472	430	413	378	400	421	442	435	432	457	527
2002	PEAK		724	718	621	571	472	513	590	602	555	610	650	724
	ENERGY	446	543	472	430	414	378	400	421	442	435	433	457	528
2003	PEAK		725	719	622	571	472	514	590	602	556	610	650	724
	ENERGY	447	544	473	430	414	378	401	422	443	435	433	458	528
2004	PEAK		727	720	623	573	473	515	592	604	557	612	652	726
	ENERGY	448	545	474	431	415	379	401	423	444	436	434	459	530
2005	PEAK		730	723	626	575	475	517	594	606	559	614	655	729
	ENERGY	449	547	476	433	417	381	403	424	445	438	436	461	532
2006	PEAK		732	725	627	576	476	518	596	608	561	616	656	731
	ENERGY	451	549	477	434	418	382	404	425	447	439	437	462	533
2007	PEAK		736	730	631	580	479	521	599	611	564	619	660	735
	ENERGY	453	552	480	437	420	384	407	428	449	442	440	465	536
2008	PEAK		739	733	634	583	481	524	602	614	566	622	663	739
	ENERGY	455	555	482	439	422	386	408	430	451	444	442	467	539
2009	PEAK		743	736	637	585	483	526	604	617	569	625	666	742
	ENERGY	457	557	484	441	424	387	410	432	453	446	444	469	541
2010	PEAK		745	739	639	587	485	528	607	619	571	627	669	745
	ENERGY	459	559	486	443	426	389	412	433	455	448	445	471	543
2011	PEAK		746	740	640	588	486	529	608	620	572	628	670	746
	ENERGY	460	560	487	443	426	389	412	434	456	448	446	471	544
2012	PEAK		748	741	641	589	487	530	609	621	573	629	671	747
	ENERGY	461	561	488	444	427	390	413	435	456	449	447	472	545

Pacificorp Electric Operations - Firm Load - RAMPP II Low Forecast

Pacific Division - Idaho

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		48	44	46	38	33	26	30	30	28	43	42	53
	ENERGY	28	35	33	31	28	24	23	22	23	23	26	30	34
1992	PEAK		48	44	46	38	33	26	30	30	29	43	42	53
	ENERGY	28	35	33	31	28	24	23	22	23	23	26	30	34
1993	PEAK		49	45	47	39	33	27	31	31	29	43	42	54
	ENERGY	28	36	33	32	28	24	23	22	23	24	26	31	35
1994	PEAK		50	45	47	39	34	27	31	31	29	44	43	55
	ENERGY	28	36	34	32	29	25	23	22	24	24	27	31	35
1995	PEAK		50	46	48	40	34	27	31	31	29	44	43	55
	ENERGY	29	36	34	32	29	25	24	22	24	24	27	31	35
1996	PEAK		50	46	48	40	34	27	31	31	29	44	43	55
	ENERGY	29	36	34	32	29	25	24	22	24	24	27	31	35
1997	PEAK		50	46	48	40	34	27	31	31	30	44	43	55
	ENERGY	29	36	34	33	29	25	24	22	24	24	27	31	35
1998	PEAK		50	46	48	40	34	27	32	32	30	45	44	55
	ENERGY	29	37	34	33	29	25	24	23	24	24	27	32	36
1999	PEAK		51	47	49	40	35	28	32	32	30	45	44	56
	ENERGY	29	37	34	33	29	25	24	23	24	25	27	32	36
2000	PEAK		51	47	49	41	35	28	32	32	30	45	45	57
	ENERGY	29	37	35	33	30	25	24	23	24	25	28	32	37
2001	PEAK		52	47	49	41	35	28	32	32	31	46	45	57
	ENERGY	30	38	35	34	30	26	24	23	25	25	28	32	37
2002	PEAK		52	47	49	41	35	28	32	33	31	46	45	57
	ENERGY	30	38	35	34	30	26	24	23	25	25	28	33	37
2003	PEAK		52	47	49	41	35	28	32	33	31	46	45	57
	ENERGY	30	38	35	34	30	26	24	23	25	25	28	33	37
2004	PEAK		52	48	50	41	35	28	33	33	31	46	45	57
	ENERGY	30	38	35	34	30	26	25	23	25	25	28	33	37
2005	PEAK		53	48	50	42	36	29	33	33	31	47	46	58
	ENERGY	30	38	36	34	30	26	25	24	25	26	28	33	37
2006	PEAK		53	48	51	42	36	29	33	33	31	47	46	58
	ENERGY	30	39	36	35	31	26	25	24	25	26	29	33	38
2007	PEAK		53	49	51	43	36	29	34	34	32	47	46	59
	ENERGY	31	39	36	35	31	26	25	24	25	26	29	34	38
2008	PEAK		54	49	51	43	37	29	34	34	32	48	47	59
	ENERGY	31	39	37	35	31	27	25	24	26	26	29	34	38
2009	PEAK		54	50	52	43	37	30	34	34	32	48	47	60
	ENERGY	31	40	37	36	31	27	26	24	26	26	29	34	39
2010	PEAK		55	50	52	44	37	30	35	35	32	49	48	61
	ENERGY	32	40	37	36	32	27	26	25	26	27	30	35	39
2011	PEAK		55	50	52	44	37	30	34	35	32	49	48	61
	ENERGY	32	40	37	36	32	27	26	25	26	27	30	35	39
2012	PEAK		55	50	53	44	37	30	35	35	33	49	48	61
	ENERGY	32	40	37	36	32	27	26	25	26	27	30	35	39

Pacificorp Electric Operations - Firm Load - RAMPP II Low Forecast

Pacific Division - Montana

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		153	142	140	127	98	97	98	96	92	117	132	154
	ENERGY	89	113	100	99	90	76	77	76	76	80	82	95	107
1992	PEAK		153	142	140	127	98	97	98	96	92	117	131	153
	ENERGY	89	113	100	99	89	76	77	76	76	80	82	95	107
1993	PEAK		154	143	141	128	99	98	99	97	93	118	133	155
	ENERGY	90	114	101	100	90	77	77	77	77	81	83	96	108
1994	PEAK		155	144	142	129	99	99	99	97	93	119	134	156
	ENERGY	91	115	102	101	91	77	78	77	77	81	84	96	108
1995	PEAK		156	145	143	129	100	99	100	98	94	119	134	157
	ENERGY	91	116	102	101	91	78	78	78	78	82	84	97	109
1996	PEAK		156	145	143	129	100	99	100	98	94	119	134	157
	ENERGY	91	116	102	101	91	78	78	78	78	82	84	97	109
1997	PEAK		156	145	143	129	100	99	100	98	93	119	134	156
	ENERGY	91	116	102	101	91	77	78	78	77	82	84	97	109
1998	PEAK		157	146	144	130	101	100	101	98	94	120	135	158
	ENERGY	92	117	103	102	92	78	79	78	78	82	85	98	110
1999	PEAK		159	148	146	132	102	101	102	100	96	122	137	160
	ENERGY	93	118	105	103	93	79	80	79	79	84	86	99	111
2000	PEAK		162	150	148	134	103	102	103	101	97	124	139	162
	ENERGY	94	120	106	105	95	80	81	80	80	85	87	100	113
2001	PEAK		163	151	149	135	104	103	104	102	98	125	140	163
	ENERGY	95	121	107	106	95	81	82	81	81	85	88	101	114
2002	PEAK		163	151	149	135	104	103	104	102	98	125	140	164
	ENERGY	95	121	107	106	96	81	82	81	81	85	88	101	114
2003	PEAK		163	151	149	135	104	103	104	102	98	124	140	163
	ENERGY	95	121	107	105	95	81	82	81	81	85	87	101	113
2004	PEAK		164	152	150	136	105	104	105	103	98	125	141	164
	ENERGY	96	121	107	106	96	81	82	82	81	86	88	102	114
2005	PEAK		167	155	153	138	107	106	107	104	100	128	144	167
	ENERGY	97	124	109	108	98	83	84	83	83	87	90	103	116
2006	PEAK		169	157	155	140	108	107	108	106	101	129	145	169
	ENERGY	99	125	111	109	99	84	85	84	84	88	91	105	118
2007	PEAK		171	159	157	142	110	109	110	107	103	131	147	172
	ENERGY	100	127	112	111	100	85	86	85	85	90	92	106	120
2008	PEAK		173	161	159	144	111	110	111	108	104	133	149	174
	ENERGY	101	128	114	112	101	86	87	86	86	91	93	107	121
2009	PEAK		175	163	160	145	112	111	112	110	105	134	151	176
	ENERGY	102	130	115	114	103	87	88	87	87	92	94	109	122
2010	PEAK		177	164	162	146	113	112	113	111	106	135	152	177
	ENERGY	103	131	116	114	103	88	89	88	88	93	95	110	123
2011	PEAK		176	164	161	146	113	112	113	110	106	135	152	177
	ENERGY	103	131	116	114	103	88	89	88	88	92	95	109	123
2012	PEAK		177	165	162	147	113	112	113	111	106	136	152	178
	ENERGY	103	131	116	115	104	88	89	88	88	93	95	110	124

Pacificorp Electric Operations - Firm Load - RAMPP II Low Forecast

Pacific Division - California

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		140	136	129	133	122	128	142	126	113	119	128	148
	ENERGY	92	105	90	87	87	92	98	102	95	85	81	84	102
1992	PEAK		140	135	128	132	122	128	142	125	113	118	127	147
	ENERGY	92	105	89	86	86	92	98	101	95	84	81	83	101
1993	PEAK		141	137	130	133	123	129	143	126	114	119	128	148
	ENERGY	93	106	90	87	87	93	99	102	96	85	82	84	102
1994	PEAK		142	137	130	134	123	129	144	127	114	120	129	149
	ENERGY	93	106	90	88	87	93	99	103	96	85	82	85	103
1995	PEAK		141	136	129	133	122	129	143	126	113	119	128	148
	ENERGY	92	105	90	87	87	92	98	102	95	85	81	84	102
1996	PEAK		139	135	128	132	121	127	141	125	112	118	127	147
	ENERGY	92	104	89	86	86	91	98	101	94	84	81	83	101
1997	PEAK		138	134	127	131	121	127	140	124	112	117	126	146
	ENERGY	91	104	88	86	85	91	97	100	94	83	80	83	100
1998	PEAK		138	133	127	130	120	126	140	123	111	116	125	145
	ENERGY	91	103	88	85	85	90	96	100	93	83	80	82	100
1999	PEAK		137	133	126	129	119	125	139	123	110	116	125	144
	ENERGY	90	103	87	85	85	90	96	99	93	83	79	82	99
2000	PEAK		136	132	125	129	119	125	138	122	110	115	124	143
	ENERGY	90	102	87	84	84	89	95	99	92	82	79	81	99
2001	PEAK		135	131	124	128	118	124	137	121	109	114	123	142
	ENERGY	89	101	86	84	83	89	95	98	92	81	78	81	98
2002	PEAK		134	130	123	126	117	122	136	120	108	113	122	141
	ENERGY	88	100	85	83	83	88	94	97	91	81	77	80	97
2003	PEAK		133	128	122	125	115	121	134	119	107	112	121	140
	ENERGY	87	99	85	82	82	87	93	96	90	80	77	79	96
2004	PEAK		132	127	121	124	115	120	133	118	106	111	120	138
	ENERGY	87	99	84	81	81	86	92	96	89	79	76	79	95
2005	PEAK		131	127	120	124	114	120	133	117	105	111	119	138
	ENERGY	86	98	83	81	81	86	92	95	89	79	76	78	95
2006	PEAK		130	126	120	123	113	119	132	116	105	110	118	137
	ENERGY	86	98	83	80	80	85	91	94	88	78	75	78	94
2007	PEAK		129	125	119	122	113	118	131	116	104	109	118	136
	ENERGY	85	97	83	80	80	85	91	94	88	78	75	77	94
2008	PEAK		129	125	119	122	112	118	131	115	104	109	117	136
	ENERGY	85	97	82	80	80	85	90	94	87	78	75	77	93
2009	PEAK		129	125	118	122	112	118	130	115	104	109	117	135
	ENERGY	85	97	82	80	79	84	90	93	87	78	75	77	93
2010	PEAK		128	124	118	121	112	117	130	115	103	108	117	135
	ENERGY	84	96	82	79	79	84	90	93	87	77	74	77	93
2011	PEAK		127	123	117	120	111	116	129	114	102	107	116	134
	ENERGY	84	95	81	79	78	83	89	92	86	77	74	76	92
2012	PEAK		126	122	116	119	110	115	128	113	102	107	115	133
	ENERGY	83	95	81	78	78	83	88	92	86	76	73	75	91

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Pacific Division - Wyoming

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		965	941	937	898	832	935	889	898	899	870	924	964
	ENERGY	834	888	895	849	841	755	815	802	807	816	809	853	879
1992	PEAK		970	946	942	903	836	940	893	903	903	875	928	969
	ENERGY	838	892	900	854	845	759	819	806	811	820	813	857	883
1993	PEAK		989	965	960	921	852	959	911	921	921	892	947	988
	ENERGY	854	910	918	871	862	774	836	822	827	837	829	874	901
1994	PEAK		1006	981	977	937	867	975	927	937	937	907	963	1005
	ENERGY	869	926	934	886	877	788	850	836	841	851	843	889	916
1995	PEAK		1016	990	986	945	875	984	935	945	946	916	972	1014
	ENERGY	877	934	942	894	885	795	858	844	849	859	851	897	925
1996	PEAK		1025	999	995	954	883	993	944	954	954	924	981	1024
	ENERGY	885	943	951	902	893	802	866	852	857	867	859	906	933
1997	PEAK		1038	1012	1007	966	894	1005	955	966	966	935	993	1036
	ENERGY	896	955	963	913	904	812	877	862	868	877	869	917	945
1998	PEAK		1051	1025	1021	979	906	1019	968	978	979	948	1006	1050
	ENERGY	908	967	975	925	916	823	888	874	879	889	881	929	957
1999	PEAK		1065	1039	1034	992	918	1032	981	991	992	960	1019	1064
	ENERGY	920	980	988	938	928	834	900	885	891	901	893	941	970
2000	PEAK		1078	1051	1047	1004	929	1045	993	1003	1004	972	1032	1077
	ENERGY	931	992	1000	949	940	844	911	896	902	912	903	953	982
2001	PEAK		1092	1064	1060	1016	941	1058	1005	1016	1016	984	1045	1090
	ENERGY	943	1004	1013	961	951	854	922	907	913	923	915	965	994
2002	PEAK		1106	1078	1073	1029	953	1071	1018	1029	1029	997	1058	1104
	ENERGY	955	1017	1026	973	964	865	934	919	924	935	926	977	1007
2003	PEAK		1117	1089	1085	1040	963	1083	1029	1040	1040	1007	1069	1116
	ENERGY	965	1028	1037	983	974	874	944	928	934	945	936	987	1017
2004	PEAK		1129	1101	1096	1051	973	1094	1040	1051	1051	1018	1081	1128
	ENERGY	975	1039	1048	994	984	884	954	938	944	955	946	998	1028
2005	PEAK		1142	1114	1109	1063	984	1107	1052	1063	1063	1030	1093	1141
	ENERGY	987	1051	1060	1005	995	894	965	949	955	966	957	1009	1040
2006	PEAK		1155	1127	1122	1076	996	1120	1064	1075	1076	1042	1106	1154
	ENERGY	998	1063	1072	1017	1007	904	976	960	966	977	968	1021	1052
2007	PEAK		1168	1139	1134	1088	1007	1132	1076	1087	1088	1053	1118	1167
	ENERGY	1009	1075	1084	1028	1018	914	987	971	977	988	979	1033	1064
2008	PEAK		1180	1150	1146	1098	1017	1143	1086	1098	1099	1064	1129	1178
	ENERGY	1019	1085	1095	1039	1028	923	997	980	987	998	989	1043	1074
2009	PEAK		1190	1161	1156	1108	1026	1153	1096	1108	1108	1073	1139	1189
	ENERGY	1028	1095	1104	1048	1037	932	1006	989	995	1007	997	1052	1084
2010	PEAK		1200	1170	1165	1117	1034	1163	1105	1117	1117	1082	1148	1198
	ENERGY	1036	1104	1113	1056	1046	939	1014	997	1003	1015	1005	1060	1092
2011	PEAK		1213	1183	1178	1129	1045	1175	1117	1129	1129	1094	1161	1212
	ENERGY	1048	1116	1125	1068	1057	949	1025	1008	1014	1026	1016	1072	1104
2012	PEAK		1227	1196	1191	1142	1057	1189	1130	1142	1142	1106	1174	1225
	ENERGY	1060	1129	1138	1080	1069	960	1036	1020	1026	1038	1028	1084	1117

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Utah Division - Idaho

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		251	245	242	133	151	337	436	369	275	227	240	250
	ENERGY	201	181	158	163	98	145	255	386	294	198	182	156	183
1992	PEAK		247	233	242	131	146	333	433	373	280	229	245	249
	ENERGY	200	176	155	162	95	138	251	378	296	202	185	162	182
1993	PEAK		269	253	262	147	162	360	466	402	303	250	266	271
	ENERGY	218	194	172	178	109	154	273	406	320	222	203	178	200
1994	PEAK		283	266	276	157	172	378	487	421	318	264	280	285
	ENERGY	231	205	182	189	117	164	287	425	336	234	214	190	211
1995	PEAK		286	269	279	160	174	382	492	425	322	268	283	289
	ENERGY	234	208	185	192	119	166	290	429	339	237	217	192	214
1996	PEAK		289	273	282	162	177	386	497	429	326	271	287	292
	ENERGY	236	211	188	195	121	169	294	433	343	240	220	195	217
1997	PEAK		293	276	286	164	179	391	502	434	329	274	290	296
	ENERGY	239	213	190	197	124	171	297	438	347	243	223	197	220
1998	PEAK		296	279	289	167	182	395	507	438	333	277	293	299
	ENERGY	242	217	199	205	114	185	281	426	341	251	213	205	217
1999	PEAK		298	276	287	181	173	419	528	453	331	294	292	309
	ENERGY	245	220	201	207	116	187	284	431	344	254	215	208	219
2000	PEAK		301	279	290	184	175	423	532	457	334	297	294	311
	ENERGY	248	222	204	210	117	189	287	434	348	256	218	210	222
2001	PEAK		303	280	291	185	176	425	534	459	336	298	296	313
	ENERGY	249	223	205	211	118	190	288	436	349	258	219	211	223
2002	PEAK		304	281	293	185	177	426	536	460	337	299	297	314
	ENERGY	250	224	206	212	119	191	289	438	350	259	220	212	224
2003	PEAK		303	281	292	185	176	426	535	460	337	299	297	314
	ENERGY	250	224	205	211	119	191	289	437	350	258	220	212	223
2004	PEAK		304	281	292	185	177	426	536	460	337	299	297	314
	ENERGY	250	224	205	212	119	191	289	438	350	258	220	212	224
2005	PEAK		306	283	295	187	178	429	539	463	340	301	299	316
	ENERGY	252	226	207	213	120	193	292	441	353	261	222	214	226
2006	PEAK		309	287	298	190	181	433	545	468	343	305	302	320
	ENERGY	255	229	210	216	123	195	295	445	357	264	225	216	229
2007	PEAK		312	289	301	192	183	437	549	472	346	307	305	323
	ENERGY	258	231	212	218	124	197	298	449	360	266	227	219	231
2008	PEAK		314	292	303	193	184	440	552	474	349	310	307	325
	ENERGY	260	233	214	220	126	199	300	452	362	268	229	220	233
2009	PEAK		315	292	304	194	185	441	554	476	350	310	308	326
	ENERGY	260	234	215	221	126	200	301	453	363	269	230	221	234
2010	PEAK		317	299	310	183	197	422	539	467	355	298	314	321
	ENERGY	261	233	209	216	139	189	322	470	374	265	243	217	240
2011	PEAK		317	299	310	183	197	422	539	467	356	298	314	321
	ENERGY	261	234	209	216	139	189	322	470	374	265	243	217	240
2012	PEAK		317	299	309	182	196	421	538	466	355	298	314	320
	ENERGY	261	233	209	216	138	189	321	470	374	264	243	216	240

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Utah Division - Wyoming

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		302	285	268	257	247	212	228	258	224	263	258	283
	ENERGY	251	284	288	239	251	241	256	227	251	226	247	237	268
1992	PEAK		302	284	267	256	246	211	227	258	223	262	258	282
	ENERGY	250	283	287	239	250	241	255	226	250	225	246	236	267
1993	PEAK		301	283	266	255	245	210	227	257	222	261	257	281
	ENERGY	249	282	286	238	249	240	254	226	249	225	245	235	266
1994	PEAK		300	283	266	255	244	210	226	256	222	261	256	281
	ENERGY	249	282	285	237	249	239	254	225	249	224	245	235	266
1995	PEAK		299	282	265	254	244	209	225	255	221	260	255	280
	ENERGY	248	281	285	236	248	239	253	224	248	223	244	234	265
1996	PEAK		298	280	264	253	243	208	224	254	220	259	254	279
	ENERGY	247	280	283	235	247	238	252	223	247	222	243	233	264
1997	PEAK		298	281	264	253	243	208	224	254	220	259	254	279
	ENERGY	247	280	283	235	247	238	252	224	247	222	243	233	264
1998	PEAK		298	281	264	253	243	209	225	255	221	259	255	279
	ENERGY	248	280	284	236	247	238	253	224	248	223	244	234	264
1999	PEAK		299	282	265	254	244	210	226	256	221	260	256	280
	ENERGY	249	281	285	237	248	239	253	225	249	224	244	234	265
2000	PEAK		300	283	266	255	245	210	226	256	222	261	256	281
	ENERGY	249	282	286	237	249	240	254	225	249	224	245	235	266
2001	PEAK		301	284	267	256	246	211	227	257	223	262	257	282
	ENERGY	250	283	287	238	250	241	255	226	250	225	246	236	267
2002	PEAK		303	286	268	257	247	212	228	259	224	263	259	284
	ENERGY	252	285	288	240	251	242	257	227	252	226	247	237	268
2003	PEAK		304	286	269	258	248	213	229	260	225	264	259	284
	ENERGY	252	286	289	240	252	243	257	228	252	227	248	238	269
2004	PEAK		304	287	269	258	248	213	229	260	225	264	260	285
	ENERGY	253	286	290	241	252	243	258	228	253	227	248	238	269
2005	PEAK		304	287	269	258	248	213	229	260	225	264	260	285
	ENERGY	253	286	290	241	252	243	258	228	253	227	248	238	269
2006	PEAK		304	287	269	258	248	213	229	260	225	264	260	285
	ENERGY	253	286	290	241	252	243	258	228	253	227	248	238	269
2007	PEAK		304	286	269	258	248	213	229	260	225	264	260	285
	ENERGY	252	286	289	240	252	243	257	228	252	227	248	238	269
2008	PEAK		303	285	268	257	247	212	228	259	224	263	259	283
	ENERGY	251	284	288	239	251	242	256	227	251	226	247	237	268
2009	PEAK		301	284	267	256	245	211	227	257	223	262	257	282
	ENERGY	250	283	287	238	250	240	255	226	250	225	246	236	267
2010	PEAK		299	282	265	254	244	209	225	255	221	260	255	280
	ENERGY	248	281	284	236	248	239	253	224	248	223	244	234	265
2011	PEAK		297	280	263	252	242	208	224	253	219	258	253	278
	ENERGY	246	279	282	235	246	237	251	223	246	222	242	232	263
2012	PEAK		294	278	261	250	240	206	222	252	218	256	252	276
	ENERGY	245	277	280	233	244	235	249	221	245	220	240	231	261

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Utah Division - Utah

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		1751	1801	1739	1452	1616	1920	1993	1993	1900	1554	1658	1801
	ENERGY	1362	1415	1381	1381	1193	1268	1344	1474	1449	1355	1298	1309	1465
1992	PEAK		1747	1788	1738	1450	1611	1916	1989	1996	1904	1556	1663	1800
	ENERGY	1360	1410	1378	1379	1190	1261	1338	1464	1450	1359	1299	1313	1462
1993	PEAK		1782	1824	1773	1479	1643	1954	2028	2035	1942	1587	1696	1836
	ENERGY	1387	1439	1406	1407	1215	1287	1366	1493	1480	1386	1326	1340	1492
1994	PEAK		1799	1841	1790	1494	1659	1973	2048	2055	1960	1603	1712	1853
	ENERGY	1401	1453	1420	1420	1227	1299	1379	1508	1494	1400	1339	1353	1506
1995	PEAK		1798	1840	1789	1493	1658	1972	2047	2054	1960	1602	1711	1853
	ENERGY	1400	1452	1419	1420	1227	1299	1378	1507	1493	1399	1338	1353	1506
1996	PEAK		1802	1844	1793	1496	1661	1976	2051	2058	1964	1606	1715	1857
	ENERGY	1403	1455	1422	1423	1229	1302	1381	1511	1497	1402	1341	1356	1509
1997	PEAK		1807	1850	1798	1501	1667	1982	2057	2065	1970	1611	1720	1862
	ENERGY	1408	1460	1427	1427	1233	1306	1386	1515	1501	1407	1345	1360	1514
1998	PEAK		1813	1856	1805	1506	1672	1989	2064	2071	1976	1616	1726	1869
	ENERGY	1413	1466	1438	1437	1226	1321	1370	1504	1496	1417	1337	1370	1513
1999	PEAK		1819	1857	1806	1524	1668	2017	2088	2089	1979	1635	1728	1882
	ENERGY	1418	1472	1443	1443	1230	1327	1376	1510	1502	1422	1342	1375	1519
2000	PEAK		1824	1862	1811	1528	1672	2022	2094	2095	1984	1640	1732	1887
	ENERGY	1422	1476	1447	1447	1234	1330	1380	1515	1506	1426	1346	1379	1523
2001	PEAK		1830	1868	1817	1533	1678	2029	2101	2102	1991	1645	1738	1893
	ENERGY	1427	1481	1452	1452	1238	1335	1384	1520	1511	1431	1351	1383	1528
2002	PEAK		1839	1877	1826	1541	1686	2038	2110	2111	2000	1653	1746	1902
	ENERGY	1434	1488	1459	1458	1244	1341	1391	1527	1519	1438	1357	1390	1535
2003	PEAK		1847	1886	1834	1548	1694	2048	2120	2121	2009	1661	1755	1911
	ENERGY	1440	1495	1466	1466	1250	1348	1398	1534	1526	1444	1364	1397	1543
2004	PEAK		1858	1897	1845	1557	1703	2059	2132	2133	2021	1671	1765	1922
	ENERGY	1449	1504	1475	1474	1258	1356	1406	1543	1535	1453	1372	1405	1552
2005	PEAK		1873	1912	1860	1570	1717	2076	2149	2151	2037	1684	1779	1937
	ENERGY	1461	1516	1487	1486	1269	1367	1418	1556	1548	1465	1383	1417	1565
2006	PEAK		1894	1933	1881	1588	1736	2099	2173	2174	2059	1703	1799	1959
	ENERGY	1477	1533	1503	1503	1283	1382	1434	1574	1565	1481	1399	1433	1582
2007	PEAK		1912	1952	1899	1603	1753	2119	2194	2195	2079	1720	1816	1977
	ENERGY	1492	1548	1518	1518	1296	1396	1449	1589	1580	1496	1413	1447	1598
2008	PEAK		1927	1967	1914	1616	1767	2135	2211	2212	2096	1733	1831	1993
	ENERGY	1504	1561	1530	1530	1307	1407	1461	1602	1593	1508	1425	1458	1611
2009	PEAK		1940	1980	1927	1627	1779	2150	2226	2227	2110	1745	1843	2006
	ENERGY	1514	1571	1541	1540	1316	1417	1471	1613	1604	1518	1435	1468	1622
2010	PEAK		1952	1998	1943	1625	1801	2142	2222	2230	2127	1742	1859	2012
	ENERGY	1523	1579	1544	1544	1336	1414	1500	1639	1624	1522	1456	1472	1637
2011	PEAK		1966	2011	1956	1636	1813	2156	2237	2245	2141	1754	1871	2026
	ENERGY	1534	1590	1554	1555	1345	1424	1510	1650	1635	1533	1466	1482	1648
2012	PEAK		1978	2024	1968	1646	1824	2170	2251	2258	2154	1765	1883	2038
	ENERGY	1543	1600	1564	1565	1354	1433	1519	1660	1645	1542	1476	1491	1659

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Utah Division

Year	Type	Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		2303	2330	2249	1840	2013	2469	2657	2620	2398	2043	2155	2333
	ENERGY	1813	1880	1827	1784	1541	1654	1856	2088	1993	1779	1727	1701	1915
1992	PEAK		2295	2305	2247	1837	2002	2459	2649	2626	2407	2047	2166	2331
	ENERGY	1809	1871	1820	1780	1536	1641	1844	2069	1997	1786	1731	1711	1912
1993	PEAK		2350	2360	2302	1881	2049	2524	2720	2693	2467	2099	2219	2387
	ENERGY	1854	1916	1864	1824	1573	1682	1893	2126	2050	1832	1774	1754	1959
1994	PEAK		2380	2390	2332	1905	2074	2560	2759	2730	2500	2128	2248	2419
	ENERGY	1879	1941	1888	1848	1593	1704	1919	2158	2079	1857	1799	1777	1984
1995	PEAK		2382	2391	2333	1906	2075	2563	2763	2733	2502	2129	2250	2420
	ENERGY	1881	1942	1889	1849	1593	1705	1921	2161	2082	1859	1800	1778	1985
1996	PEAK		2388	2397	2339	1911	2080	2570	2771	2741	2508	2135	2256	2426
	ENERGY	1886	1946	1893	1854	1597	1709	1927	2168	2087	1864	1805	1783	1990
1997	PEAK		2397	2406	2348	1918	2087	2580	2783	2752	2518	2143	2265	2436
	ENERGY	1893	1954	1900	1861	1603	1716	1934	2177	2096	1872	1812	1790	1998
1998	PEAK		2407	2416	2358	1927	2096	2592	2795	2764	2529	2153	2274	2446
	ENERGY	1902	1962	1921	1878	1587	1743	1903	2154	2084	1889	1793	1808	1993
1999	PEAK		2418	2415	2360	1959	2085	2645	2843	2799	2531	2190	2275	2471
	ENERGY	1911	1972	1930	1887	1594	1752	1912	2165	2094	1899	1802	1817	2002
2000	PEAK		2427	2424	2368	1966	2093	2655	2853	2809	2540	2198	2283	2480
	ENERGY	1918	1979	1937	1894	1600	1758	1920	2173	2102	1906	1809	1824	2010
2001	PEAK		2435	2432	2376	1974	2100	2664	2863	2819	2549	2206	2291	2489
	ENERGY	1925	1986	1944	1901	1606	1765	1927	2181	2110	1913	1816	1830	2017
2002	PEAK		2446	2444	2387	1983	2110	2676	2876	2831	2561	2216	2302	2500
	ENERGY	1934	1996	1953	1910	1614	1773	1936	2191	2120	1921	1824	1839	2026
2003	PEAK		2455	2453	2396	1991	2119	2685	2885	2841	2570	2224	2310	2510
	ENERGY	1941	2003	1960	1917	1621	1780	1943	2199	2127	1929	1831	1846	2034
2004	PEAK		2467	2464	2408	2000	2129	2698	2898	2854	2582	2235	2321	2521
	ENERGY	1951	2013	1970	1926	1629	1788	1952	2208	2137	1938	1840	1855	2044
2005	PEAK		2484	2482	2425	2015	2145	2718	2919	2874	2601	2251	2338	2539
	ENERGY	1965	2027	1984	1940	1641	1801	1966	2224	2152	1952	1854	1868	2059
2006	PEAK		2508	2506	2449	2035	2166	2745	2948	2903	2627	2273	2361	2564
	ENERGY	1984	2047	2003	1960	1658	1819	1986	2246	2173	1971	1872	1887	2079
2007	PEAK		2529	2527	2469	2052	2185	2768	2973	2927	2650	2292	2381	2585
	ENERGY	2001	2064	2020	1976	1672	1835	2003	2266	2192	1988	1888	1903	2097
2008	PEAK		2545	2544	2486	2066	2199	2787	2992	2946	2668	2307	2396	2602
	ENERGY	2014	2077	2032	1989	1684	1847	2016	2281	2206	2001	1901	1916	2111
2009	PEAK		2557	2556	2498	2076	2211	2801	3007	2961	2681	2318	2408	2615
	ENERGY	2024	2087	2042	1999	1692	1855	2026	2291	2217	2011	1910	1925	2121
2010	PEAK		2567	2579	2517	2061	2240	2772	2985	2950	2702	2300	2428	2611
	ENERGY	2031	2094	2037	1998	1722	1842	2074	2334	2247	2010	1944	1922	2143
2011	PEAK		2578	2590	2528	2070	2250	2785	2999	2964	2715	2310	2439	2623
	ENERGY	2040	2103	2046	2007	1730	1851	2083	2344	2256	2019	1953	1931	2152
2012	PEAK		2588	2600	2538	2078	2259	2796	3010	2975	2726	2319	2448	2633
	ENERGY	2047	2111	2053	2014	1736	1857	2090	2352	2264	2026	1960	1938	2160

Pacificorp Electric Operations - Firm Load - RAMPP II Low Forecast

Pacific Division

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		4304	4253	4062	3861	3402	3398	3487	3522	3436	3743	4040	4461
	ENERGY	2969	3410	3151	2995	2901	2697	2779	2778	2853	2834	2826	3073	3345
1992	PEAK		4292	4241	4051	3850	3392	3390	3480	3514	3428	3733	4029	4449
	ENERGY	2963	3402	3144	2989	2894	2691	2773	2773	2847	2829	2821	3066	3337
1993	PEAK		4362	4310	4117	3913	3448	3446	3536	3572	3485	3794	4095	4521
	ENERGY	3012	3458	3196	3038	2942	2735	2819	2818	2894	2876	2867	3117	3392
1994	PEAK		4404	4351	4156	3950	3481	3481	3571	3607	3519	3830	4134	4564
	ENERGY	3042	3492	3228	3069	2972	2762	2848	2847	2923	2905	2896	3148	3426
1995	PEAK		4401	4349	4154	3947	3479	3480	3571	3607	3518	3828	4131	4560
	ENERGY	3043	3492	3229	3069	2973	2762	2848	2847	2924	2905	2897	3148	3425
1996	PEAK		4395	4342	4147	3941	3473	3478	3567	3603	3515	3823	4125	4553
	ENERGY	3040	3489	3227	3067	2971	2760	2847	2846	2922	2904	2895	3146	3422
1997	PEAK		4396	4343	4148	3941	3474	3481	3570	3606	3518	3824	4126	4553
	ENERGY	3044	3491	3230	3070	2974	2762	2850	2849	2925	2907	2898	3149	3425
1998	PEAK		4406	4352	4157	3950	3482	3490	3579	3615	3527	3833	4135	4562
	ENERGY	3052	3501	3240	3079	2983	2770	2859	2858	2934	2916	2907	3158	3434
1999	PEAK		4419	4365	4170	3962	3493	3503	3591	3628	3539	3845	4148	4575
	ENERGY	3064	3513	3253	3091	2995	2780	2870	2869	2945	2927	2919	3170	3447
2000	PEAK		4430	4375	4180	3971	3501	3513	3601	3638	3549	3854	4157	4585
	ENERGY	3073	3523	3263	3100	3004	2788	2879	2877	2954	2936	2928	3179	3456
2001	PEAK		4443	4387	4192	3983	3512	3525	3612	3649	3561	3866	4169	4598
	ENERGY	3084	3535	3275	3112	3015	2798	2889	2888	2964	2947	2938	3191	3468
2002	PEAK		4456	4400	4205	3995	3523	3538	3624	3662	3573	3878	4182	4611
	ENERGY	3096	3547	3288	3124	3027	2809	2901	2899	2975	2959	2950	3202	3480
2003	PEAK		4463	4407	4212	4001	3529	3546	3631	3669	3580	3884	4189	4618
	ENERGY	3103	3554	3295	3131	3034	2815	2907	2906	2982	2966	2957	3210	3487
2004	PEAK		4479	4422	4227	4015	3542	3560	3645	3682	3594	3898	4204	4633
	ENERGY	3116	3568	3309	3144	3047	2826	2919	2917	2994	2978	2969	3223	3501
2005	PEAK		4506	4449	4253	4040	3563	3582	3667	3705	3617	3922	4229	4661
	ENERGY	3136	3591	3330	3164	3067	2844	2938	2936	3013	2997	2988	3243	3523
2006	PEAK		4530	4473	4276	4062	3583	3603	3687	3726	3637	3943	4252	4686
	ENERGY	3154	3612	3350	3183	3085	2861	2956	2953	3031	3015	3006	3263	3543
2007	PEAK		4562	4504	4306	4091	3608	3629	3714	3752	3663	3971	4282	4719
	ENERGY	3177	3638	3375	3207	3108	2882	2978	2975	3053	3037	3028	3287	3569
2008	PEAK		4591	4533	4334	4117	3632	3653	3738	3777	3687	3996	4310	4749
	ENERGY	3199	3662	3398	3229	3129	2901	2998	2995	3073	3058	3049	3309	3593
2009	PEAK		4621	4562	4363	4144	3655	3677	3762	3801	3711	4023	4338	4780
	ENERGY	3220	3686	3421	3250	3150	2920	3018	3015	3094	3078	3069	3331	3617
2010	PEAK		4647	4588	4387	4167	3676	3698	3783	3823	3732	4045	4362	4806
	ENERGY	3238	3707	3440	3269	3168	2937	3035	3032	3111	3096	3087	3350	3637
2011	PEAK		4663	4603	4402	4182	3689	3712	3797	3837	3747	4059	4377	4822
	ENERGY	3251	3721	3455	3282	3182	2949	3048	3044	3124	3109	3099	3364	3651
2012	PEAK		4683	4623	4422	4200	3706	3730	3814	3855	3764	4077	4396	4843
	ENERGY	3268	3739	3472	3299	3198	2963	3063	3060	3139	3124	3115	3380	3668

Pacificorp Electric Operations - Firm Load - RAMPP II Low Forecast

Total Company

Year		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		6606	6583	6311	5701	5415	5867	6144	6142	5834	5786	6194	6795
	ENERGY	4783	5289	4978	4779	4441	4351	4635	4866	4846	4613	4554	4774	5260
1992	PEAK		6587	6547	6298	5687	5395	5850	6128	6140	5835	5780	6195	6780
	ENERGY	4772	5273	4964	4768	4430	4332	4618	4841	4845	4615	4551	4777	5249
1993	PEAK		6712	6670	6419	5794	5497	5970	6256	6265	5951	5893	6314	6909
	ENERGY	4866	5374	5060	4862	4515	4417	4712	4944	4944	4708	4642	4870	5351
1994	PEAK		6784	6741	6488	5855	5555	6040	6331	6338	6019	5958	6382	6982
	ENERGY	4922	5433	5116	4916	4565	4466	4767	5005	5003	4762	4695	4925	5410
1995	PEAK		6783	6740	6487	5854	5554	6043	6333	6340	6020	5958	6381	6981
	ENERGY	4924	5433	5117	4918	4566	4467	4770	5009	5005	4764	4697	4926	5411
1996	PEAK		6783	6739	6487	5852	5553	6048	6338	6344	6024	5958	6381	6979
	ENERGY	4926	5435	5120	4920	4568	4469	4773	5014	5009	4768	4700	4929	5412
1997	PEAK		6793	6749	6496	5860	5561	6061	6352	6358	6036	5968	6390	6988
	ENERGY	4937	5445	5131	4931	4577	4478	4784	5026	5021	4779	4710	4939	5423
1998	PEAK		6812	6768	6515	5876	5578	6082	6374	6379	6056	5986	6409	7008
	ENERGY	4954	5463	5161	4957	4570	4513	4761	5011	5017	4805	4700	4966	5427
1999	PEAK		6837	6780	6530	5921	5578	6148	6434	6427	6071	6035	6422	7047
	ENERGY	4975	5485	5183	4978	4589	4532	4782	5033	5039	4826	4721	4987	5449
2000	PEAK		6856	6799	6548	5937	5594	6168	6454	6447	6089	6052	6440	7065
	ENERGY	4991	5502	5200	4994	4605	4547	4798	5051	5056	4842	4737	5003	5466
2001	PEAK		6878	6820	6569	5956	5612	6189	6476	6468	6110	6072	6460	7087
	ENERGY	5010	5521	5219	5013	4622	4563	4816	5069	5074	4860	4754	5021	5485
2002	PEAK		6902	6844	6593	5978	5633	6214	6500	6493	6134	6094	6484	7111
	ENERGY	5030	5543	5240	5034	4642	4582	4837	5090	5095	4880	4774	5041	5507
2003	PEAK		6918	6860	6608	5992	5647	6231	6517	6510	6151	6108	6499	7127
	ENERGY	5044	5558	5256	5048	4655	4595	4851	5104	5109	4894	4788	5056	5522
2004	PEAK		6945	6887	6634	6016	5671	6258	6543	6537	6177	6133	6524	7155
	ENERGY	5066	5581	5278	5070	4676	4614	4872	5126	5131	4916	4809	5078	5545
2005	PEAK		6990	6931	6678	6055	5708	6300	6586	6580	6218	6172	6567	7200
	ENERGY	5100	5618	5314	5105	4708	4645	4905	5161	5165	4949	4842	5112	5582
2006	PEAK		7038	6979	6725	6097	5749	6347	6635	6628	6264	6216	6613	7250
	ENERGY	5138	5658	5353	5143	4743	4680	4942	5200	5204	4986	4878	5150	5623
2007	PEAK		7091	7032	6776	6143	5793	6397	6686	6679	6313	6263	6663	7304
	ENERGY	5178	5702	5395	5183	4781	4716	4981	5241	5245	5025	4917	5190	5666
2008	PEAK		7137	7077	6820	6183	5831	6440	6730	6723	6355	6303	6706	7351
	ENERGY	5212	5739	5430	5218	4813	4747	5014	5275	5280	5059	4949	5224	5703
2009	PEAK		7179	7119	6860	6220	5866	6478	6769	6762	6393	6341	6746	7395
	ENERGY	5244	5773	5463	5249	4842	4776	5044	5306	5310	5089	4979	5256	5737
2010	PEAK		7214	7166	6904	6228	5916	6470	6768	6773	6434	6345	6790	7417
	ENERGY	5270	5801	5478	5267	4890	4779	5109	5366	5358	5106	5031	5272	5780
2011	PEAK		7241	7193	6930	6252	5939	6497	6796	6801	6461	6369	6816	7445
	ENERGY	5292	5824	5500	5289	4911	4799	5130	5388	5380	5127	5052	5294	5803
2012	PEAK		7271	7223	6959	6278	5965	6526	6824	6829	6490	6396	6844	7475
	ENERGY	5315	5849	5525	5313	4934	4820	5153	5411	5404	5150	5075	5318	5828

Pacificorp Electric Operations - Interruptible Load - RAMPP II Forecast

		Annual Calendar Average	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1991	PEAK		289	265	286	321	267	330	321	323	299	328	301	308
	ENERGY	295	289	296	294	297	285	289	277	301	308	301	311	295
1992	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301
1993	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301
1994	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301
1995	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301
1996	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301
1997	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301
1998	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
1999	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2000	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2001	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2002	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2003	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2004	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2005	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2006	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2007	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2008	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2009	PEAK		301	306	301	304	301	304	301	301	304	301	304	301
	ENERGY	303	301	294	292	328	281	345	335	323	295	328	294	315
2010	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301
2011	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301
2012	PEAK		301	294	292	328	281	345	335	323	295	328	294	315
	ENERGY	303	301	306	301	304	301	304	301	301	304	301	304	301

BALANCED PLANNING FOR GROWTH

Technical Appendix: Demand Side Resources

Resource and Market Planning Program
RAMPP - 2

May 14, 1992

PACIFICORP

TECHNICAL DOCUMENTATION

DEMAND-SIDE PROGRAM OPTIONS

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1. Introduction

This document details Demand-Side program planning and development. The discussion focuses on a set of Demand-Side programs for inclusion in the Least Cost Planning process. Assumptions regarding end-use energy usage and individual efficiency measures are discussed in general terms. Separate technical discussion on the conservation measures is included in the supply curve documentation in this volume.

2. Conservation Planning Methodology

2.1. Energy End-use

For efficiency planning, it is important to remember that consumers do not want energy itself. Rather they want the benefits from using that energy for specific purposes. These purposes are the end-uses. Examples include heating homes, lighting offices and operating industrial machines. If those same end-uses can be achieved using less energy (higher efficiency), there will be more energy available for others. Thus, efficiency improvements serve the same function as a new source of electricity. Existing electrical end-uses are shown in Figure 1.

2.2. Utility Cost and Total Resource Cost

Discussion continues on the most appropriate test for selection of demand-side options. Use of the Total Resource Cost (TRC) concept for the planning of demand and supply-side options has been selected as a reasonable compromise. This approach requires that cost decisions be based on the sum of all direct costs, including those paid by the utility, its customers and other parties. For planning purposes, programs are ranked in order of increasing TRC. TRC includes all programmatic administration costs. TRC assists planners in making rational choices based on those costs borne by society as a whole.

Also of importance is the net cost to the utility since that will ultimately be passed to customers. Selection of programs based on TRC does not necessarily obligate the utility to pay all of the costs. Part of the TRC may be paid by the customers or government agencies. This minimizes the financial burden on the utility costs. It is necessary to balance costs. If a resource places an undue burden on customers then program viability is also questionable.

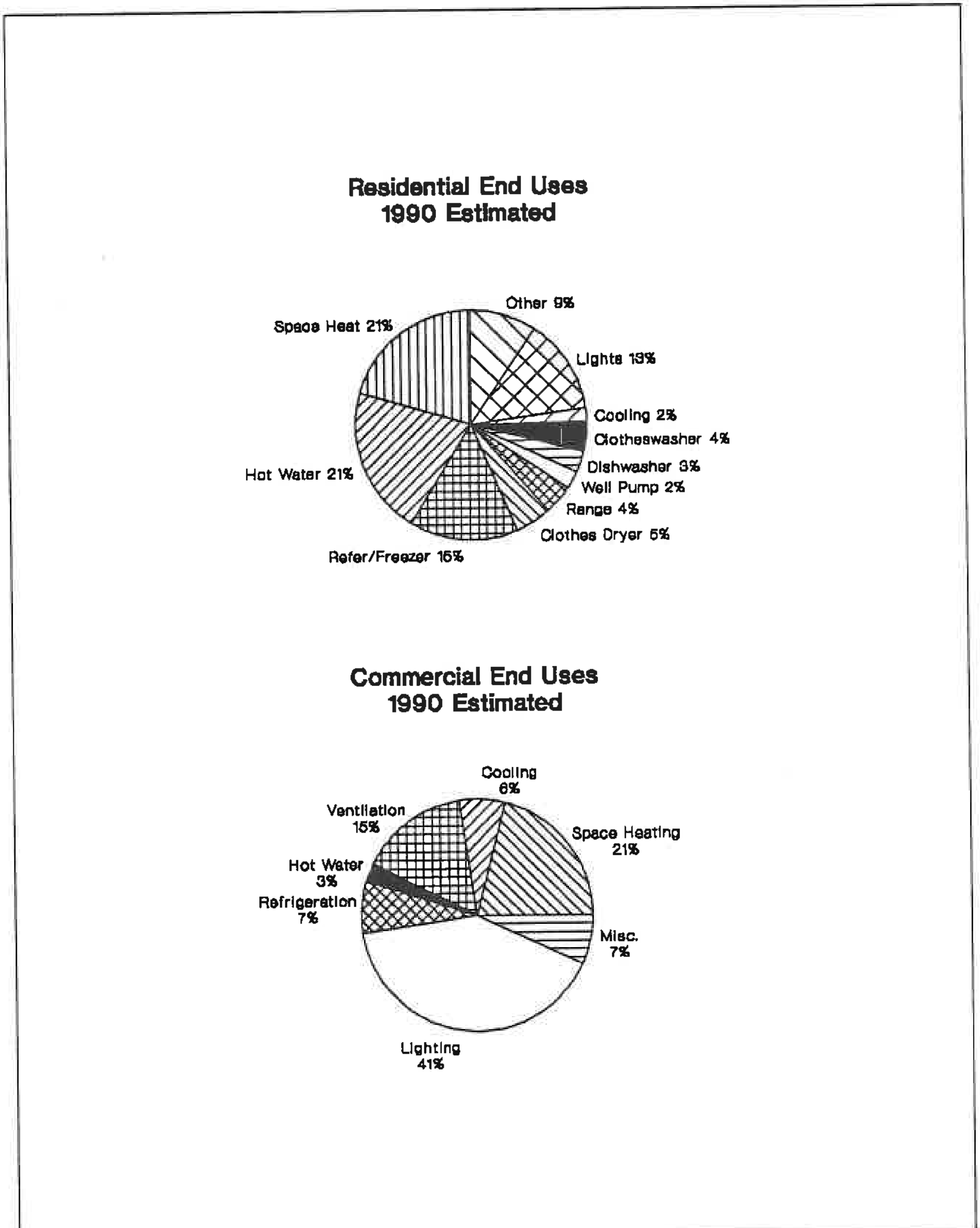

Figure 1 Company Sources and Sales

There are differences between the total resource cost and the utility net cost. For example, suppose that the utility plans for an efficiency improvement to be required by a change in building codes. That resource would require customers and builders to pay for the installation. The utility will have very little cost, so it might be expected to promote this option. However, before the utility can adopt such a planning approach, it must check to make sure that the measure meets the TRC test. It may be that the measure is too expensive for society as a whole. The Least Cost Planning approach will choose resources based on TRC but itemize costs from both perspectives.

Cost-sharing opportunities directly impact the utility's net cost. For example, government agencies have some funds available for low-income weatherization. It makes sense to combine utility programs with these other funds for maximum leverage.

The utility's cost is also influenced by the net savings produced by a program. The net energy savings may be reduced by customer takeback or "free riders". These concepts are discussed in Section 2.8. At this point, it is important to note that from the society perspective, TRC is not affected by takeback of some energy savings.

2.2.1. Two-Tiered Test of Cost-effectiveness

Cost effectiveness of demand-side resources is evaluated in a two step process. In the first step, the incremental cost of individual measures is compared to a cost ceiling for planning purposes. This ceiling was selected based on preliminary estimates of conservation cost-effectiveness expected at the end of the RAMPP-2 process. In the second step, program as a whole is compared against the cost that would otherwise be incurred for supply-side resources.

Those measures which are cost-effective in the first step are considered eligible to be in programs. Now it is necessary to estimate what programs will cost. The eligible measures are included as a package, together with estimates for administrative cost. The resulting program will have a cost based on the average of the measures and the overhead cost to deploy them. In the second step, the program cost is compared to the cost of other resources. The cost of other resources represents the maximum that the utility can be expected to pay for prudent investments. If the program cost is too high, it will be necessary to adjust the program cost. Adjustments can be made either by reducing the utility cost share or by asking the participant to return some of the savings benefits.

The cost ceiling applied in the first step may be based on a forward-looking estimate of conservation cost-effectiveness. At the moment, the Company enjoys sufficient resource to meet customer needs. Avoided cost is low, based primarily on the variable fuel cost to serve new growth with existing resources. Around 1996, however, new resources are expected to be needed. At that time, conservation programs will be scheduled for full deployment to provide new resources. The correct program strategy is to increase programs on a ramp-up schedule so that by 1996, programs are poised for full deployment. The future programs are expected to be based on measures and cost-sharing formula which will be in effect in 1996.

During the period leading up to 1996, programs will be under development. Experience will be gained through market exploration and pilot testing. The period also serves as a time to build capability by developing the supply infrastructure. All these development projects will be focused on programs to be fully deployed in the future during a period of higher avoided costs. Yet during the development period current avoided costs will not be high. Tying programs to a lower current value of avoided cost could inhibit development activities and curtail market development. Of course, the levelized value of avoided cost increases as the new resource date draws closer. However, it is not practical for programs to operate with eligibility requirements that shift and change. Contractors and suppliers like to receive consistent signals before they are willing to commit to stocking and installing conservation products.

The Company has used a "forward-looking" approach to conservation cost effectiveness during capability building. That is, for those programs being developed for later deployment, avoided costs can be based on values anticipated at the time of full deployment. The Company accomplishes this by bringing back the future value of avoided cost, corrected for inflation so that it is expressed in current year dollars. This approach only applies to capability building programs. Resource acquisition programs already in full deployment, such as new construction programs, are valued according to the current avoided cost.

2.2.2 Incremental Measure Cost

The two step method described previously starts by testing the cost effectiveness of individual measures against a cost ceiling. There is a question of what should be included in the cost of individual measures. Should those measures have program administrative cost added? The procedure suggested by the Northwest Power Planning Council (NPPC) has been followed. For most cases, incremental cost is based only on the cost and savings of the physical measures, without adding administrative cost.

Consider an example -- one is trying to decide if it is cost effective to add one more inch of insulation to an attic. The additional cost will be entirely due to the cost of the material and labor to install. There are no additional trips to the site, no additional inspections, no additional paperwork. So the administrative cost is not affected by the decision. One need only consider the incremental cost and savings of adding one more inch of insulation. This is the procedure followed by the NPPC.

Exceptions to this procedure can be imagined. For example, consider a measure consisting of retrofit heat pumps. This would be an entirely new program, requiring a different set of contractors, additional inspections and paperwork. In this case, the cost of the program should be recognized in the supply curves. For current work, however, entirely new programs of this type were not seriously pursued since they were too expensive to be cost effective.

It has been suggested that administrative cost is included in the supply-side alternative which defines the cost effective ceiling. Therefore, it should be included on demand side as well. This argument is not entirely correct because it fails to consider the inherent "lumpiness" in making these comparisons. Consider an engineer planning a thermal resource. There are a variety of optimizing decisions to make -- should one include more efficient turbines or VSD motors, for example. The engineer will chose the optimal investment for the supply-side plant following the same sort of incremental logic. Administrative cost will be added to the completed design, corresponding to treating the whole package of measures in a demand-side program. Thus, the proper comparison is between whole programs on demand side and whole resources on supply side. The cost ceiling used to test incremental measures is only a proxy to assist that process.

2.2.3. Levelized Cost Calculations

Comparison between different resources requires a common measure of cost -- whether it be utility cost or TRC. This can be difficult when conservation measures have different lifetimes and cash flows. The best option is to calculate the lifetime levelized cost. Since this cost might be incurred in different years with costs inflating, it makes sense to express costs in real (constant value) dollars.

In general, the supply curve methodology is to keep all cost calculations in real dollars and apply discounting with real discount rates. The discounting period for conservation measures is based on the lifetime of that measure. In a few cases, there are partial cash flows to be considered. For example, O&M savings are computed as present value and subtracted from the initial cost before levelizing. Another case might be a lighting option where tubes and ballasts are replaced on different schedules. This option would also require present valuing to capture the entire cost of one lifecycle.

Levelized costs for programs are more difficult, due partly to the different lifetimes of various conservation measures and the building stock. Generally a conservatively short program lifetime was assumed based on average measure lives and some assumed turnover in the building stock. For purposes of comparing resources, a real levelized TRC and utility cost were calculated for the various program options. This methodology treats the programs as having "instant costs". That is, all program costs and annual savings over the entire 20-year are summed and levelized as if they entire program occurred in one year. This method provides a value of the levelized utility cost or TRC suitable for comparing between resource choices.

The "instant cost" of a program does not consider cash flows over time. That is, a program does not occur "instantly" but rather is phased in over a period of years. Looking from the present over that future stream of expenditures produces a lower value for the sum because of discounting. The future program costs are discounted at a rate higher than inflation, therefore their present value is less than the simple sum. Under these circumstances, levelized cost is calculated by taking the net present value of the stream of future program expenditures and dividing by the 20-year sum of energy savings. This method produces a lower estimate of levelized cost due to the discounting of future expenses. It also leads to the conclusion that delay is a way to minimize resource costs. Thus, the resource choice must be weighted against the requirement to meet future loads. While delay of scheduled conservation minimizes present value costs, the delay must be constrained by the requirement to have sufficient resources.

Costs of a program are calculated based on a revenue requirement model. That is, the total cost of the program must include whatever costs would show up in prices. The program costs are treated as an investment in the Company's ratebase. The costs to service of that investment are reflected in the prices customers will pay. Debt service is treated with the Company's weighted average cost of capital, net of tax benefits. The Company has determined that this cost represents an interest rate of 9.54% nominal or 4.22% real, after correcting for inflation. This interest rate is used as the discount rate in making present value calculations.

Tax considerations enter the revenue requirement in another way as well. The amount paid by customers for debt service must be increased to also cover corporate income taxes. For some programs, this results in an increase in the lifetime cost of the program. For other programs, there are tax benefits which can reduce the income tax requirement. The net program cost over a programmatic lifetime can be presented as a NPV multiplier term. The multiplier represents the amount that the cost must be increased or decreased to assure full recovery in prices. This multiplier is used in calculating the levelized cost of different programs. Some examples of the multiplier for different types of program operation are presented below in Table 1. The same NPV multiplier terms give equivalent levelized costs as using utility fixed charge rates. The fixed charge rates incorporate the same multipliers times the appropriate capital recovery factors.

Table 1 -- NPV Multipliers for Different Programs

Program Type	Amortization Term	NPV Multiplier
Deferred Expense	5 years	0.84134
	10	0.84728
	15	0.85177
	20	0.85522
6.5% Loan	5	0.94854
	10	1.04736
	15	1.13155
	20	1.20327

The 6.5% loan program covers some residential weatherization. For purposes of current program planning, the Company will emphasize Deferred Expense treatment of new programs. This treatment means that participants may carry program payments as a service charge, not a loan. The payments will not show as increased liability on the participant's balance sheet. Cost of operating the program will be reduced -- costs will be treated as 85% of the initial investment. The Company will receive less earnings from the investment. There is a potential drawback for the participant. Federal tax laws are unclear -- the IRS might view the financing grant as taxable income and require participants to pay increased taxes. The Company will support Federal legislation to remove the tax liability from utility grants and for purposes of this plan, the Company will assume that the Federal legislation will take effect.

In this document, levelized costs are presented at several points. Levelized costs are presented for "instant" utility cost and TRC for the Long Term programs in Section 5.

2.3. Supply Curves

The conservation potential is often described with a supply curve -- that is, a function describing how much conservation is available as the price increases. The Company began the task in January, 1988 to develop a supply curve model for all of the PacifiCorp service area and customer classifications. The information was updated for the current planning process during 1991. An example supply curve for the Medium High Forecast Scenario is shown in Figure 2.

To preserve flexibility, the supply curve model was designed as a PC spreadsheet. The spreadsheet has the advantages of being transparent as far as operating assumptions and of allowing easy "what if" analysis. A series of modular, macro-linked spreadsheets were created for the market areas. The modular nature is another advantage, since changes can be incorporated without forcing massive recalculation of the entire model.

For the residential sector, the spreadsheets are separated by enduse into space heating and appliances. The space heating is modeled by assuming that homes match one of three prototypes. The prototypes have been extensively modeled by computer simulation. The information listed includes the state and climate zone for which the data was derived, the number of homes matching that prototype and a list of the energy conservation measures (ECMs) which could be applied. Details of the spreadsheet models are described in supply curve documentation.

The spreadsheets are calibrated to match existing usage records through a fuel adjustment factor. This factor accounts for use of wood heat, solar gains, prototype mismatch and other modeling uncertainties. The predicted energy savings still appear large compared to current electricity sales. An additional adjustment can be included in the model to reflect assumptions about "takeback". All these adjustments can be modified to match assumptions about how consumer behavior changes over time.

Spreadsheets for the commercial and industrial sectors have been prepared in a similar manner. For these sectors, energy usage is based directly on historic sales and market survey analysis. A calibration adjustment was not necessary. Estimates

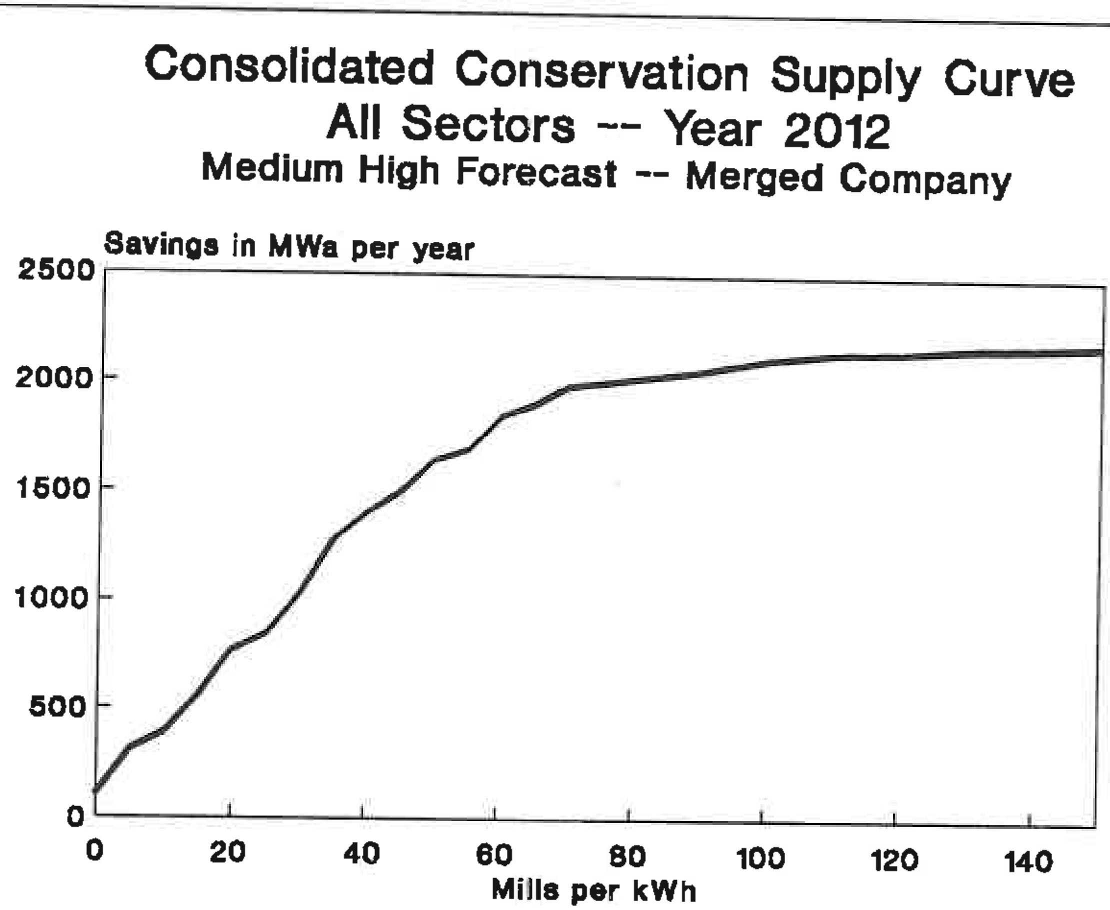

Figure 2 Supply Curve Medium High Scenario

of commercial costs and savings are derived from a series of prototype buildings modeled for Bonneville by United Industries Corporation. The industrial model differs from some other studies in that it is based on usage by specific industrial processes.

Another set of input parameters for the spreadsheets are financial ones. Pacific's initial planning assumed 4.22% real discount rate as representing the utility's cost of capital. Consumers have a different economic perspective. A high implicit discount rate (60% nominal or 52% real) has been suggested to represent all the barriers consumers perceive. Of course, not all these barriers are purely financial. The barriers include lack of knowledge, cost of obtaining information, etc. The consumer discount rate is used for calculating the amount of "background" conservation as discussed in Section 2.6.

The most important assumption for the supply curve is one's choice of a future. The amount of conservation in future years is heavily determined by the forecast of available building stock and industries. By the time that one looks out at a twenty-year planning horizon, it is difficult to predict any future path with certainty. Pacific has developing a series of four forecasts reflecting different assumptions about economic growth. Each will have a different estimate of the technical potential.

The results presented here, while illustrative and useful for planning purposes, should not be stated without considering the forecast assumption context. Sensitivity to the forecast is not a defect in the methodology, but rather a unique advantage of demand-side resources. The amount of conservation potential grows in proportion to the underlying demand growth. The more new construction occurs, the more opportunity is afforded conservation. Conservation can protect against high energy costs which would otherwise result from a high growth forecast. Thus, conservation serves to reduce the "jaws" or spread between high and low growth paths. In so doing, there is a benefit of reducing the impact on customers of forecast errors.

2.3.1. Cost Effective Ceiling

In preparing programs, it is necessary to have some idea of an upper bound on measure costs. More energy savings can be acquired if one continues to spend money. At some point, however, the diminishing returns from conservation are no longer cost-effective compared to other resource choices. Thus, there is an effective ceiling on the cost of measures one would include in a program.

Determining the cost effective ceiling is difficult because it is a function of the future scenario under consideration. That is, if one knew with perfect certainty, the resource acquisitions of the future, one could calculate precisely the cost effective ceiling at any given time. Since the ceiling influences resource choices, it might be necessary to iterate until an optimal solution is calculated. In the real world, one does not have the luxury of perfect knowledge. In practice, the ceiling is estimated based on future expectations.

The requirement for a cost effective ceiling has been a problem for some regulators. If the utility is required to limit activities to current cost effectiveness, it would not be possible to ramp up programs for acquisition under future and higher avoided costs. The Company would be unable to participate in Regional programs based on the cost effectiveness assumed by Bonneville and the Power Planning Council.

For the current planning work, a ceiling of 55 mills/kWh was used. The figure is less than the equivalent cost effective ceiling assumed by the Northwest Power Planning Council (67 mills/kWh after correcting for the different discount rates used). Nevertheless, the company expects to operate the same programs as the rest of the Region.

2.4. Technical Potential

The first step in conservation planning is to identify the size and cost of the resource. This is referred to as the technical potential. The technical potential includes all the conservation that is physically possible. However, it must be remembered that all this conservation cannot be realized. Due to market imperfections or program difficulties, not all decision makers will be persuaded to adopt optimal conservation practices. Thus, the conservation realized will always be somewhat less than that theoretically possible.

Pacific has a technical potential for conservation of about 1800 MWa based on a medium high forecast. The results by sector are listed in Table 2.

Table 2 -- Conservation Technical Potential
Average Megawatts in year 2012 at 55 mills/KWh or less
Based on Medium High Forecast, Merged Company

Sector	Technical Potential Existing Stock	New Construction	All Stock
Residential			
Space Heat	72 MWa	241 MWa	313 MWa
Appliances	----	548	548
Subtotal	72	789	861
Commercial	265	345	610
Industrial	---	---	652
Total			2123

This technical potential includes MCS and "background" conservation (206 MWa commercial, 101 MWa residential) which is assumed in the forecast. The amount of potential available for possible resource acquisition is then 1816 MWa. Of course, not all this theoretic potential is achievable today. Much of the potential savings in appliances, for example, depend on having high-efficiency appliances available. While such products might exist in Europe or Japan, they are not on the US market. The achievable potential identified in draft programs is about 800 MWa.

2.5. Lost Opportunities

Lost opportunity resources are those which, while not cost-effective at current prices, will be cost-effective over their lifetime. Also, there is only one cost-effective opportunity to capture the resource. If it is ignored then, it will probably lost be forever. An example is new construction. Failure to construct efficient buildings will lock consumers into unnecessarily high energy bills for the life of the building. Some of the conservation measures cannot be added later without prohibitive expense. The consumers will be forced to pay for a more expensive electrical system later. Thus, lost opportunity programs are beneficial to operate even during a temporary period of generation surplus. This is the rationale behind the Super Good Cents program for residential MCS and the Energy Smart program for commercial MCS.

The definition of lost opportunity resources and the timing of their acquisition is an important regional issue. The region has required that lost opportunities be addressed. Northwest utilities will face a surcharge from Bonneville if they do not comply with requirements in the residential and commercial sectors. Pacific has publicly announced its commitment to capturing lost opportunity resources consistent with prudent business practices.

Another important question for lost opportunities is that of defining cost-effectiveness relative to the expected deficit date and new resource cost. To some extent, this will not be known until completion of the integration phase of the Least Cost Planning process. Then it will be necessary to identify and reconcile any differences between regional cost-effectiveness levels and those pertaining to the individual utility. The estimate of lost opportunities at this point is clearly preliminary.

This planning process looked at lost opportunities because they do not fit into the traditional planning approach for timing programs. Normally, one would simply choose the least-cost resource first and more expensive programs would be operated later. However, lost opportunities are outside this decision rule. They need to be captured when the opportunity exists, if it is expected that the need will occur later and that they will be cost-effective within their lifetime.

A crucial acquisition consideration is the "window of opportunity", the time that an opportunity presents itself. Will there be another window or chance at the same opportunity before it is needed? If so, the opportunity could be safely postponed and not truly lost. As an example, commercial building spaces are frequently remodeled. For some measures, this means there are frequent windows. For other measures, there are not. The effect of remodel turnover rate is still subject to some uncertainty.

One finding from this initial study is to suggest that there are significant current lost opportunities. If no lost opportunity programs were conducted, Pacific might be incurring lost opportunities at a rate of about 23 MWa per year.

Table 3 -- Sources of Lost Opportunity Resources in 1991
Based on Medium High Forecast and 55 Mills/KWh Cost Ceiling
Technical Potential, MWa per Year

Sector	Technical Potential	Program
New Residential Construction	1.3 MWa	Super Good Cents
New Mfg Homes	1.4	Super Good Cents
Solar Access	0.6	Long Term SG Cents
Appliances: Refer/Freezer, Water Heater	5.0	Long Term SGCents
New Commercial Construction	11.3	Energy FinAnswer
Commercial Remodel	3.0	to be developed
Commercial Repair and Replacement	0.8	
Total Potential	23.4 MWa	

The residential sector is being addressed by the Long Term Super Good Cents program. The largest opportunity exists in commercial sector -- both new and remodeled buildings. Pacific has started a new commercial construction program and is planning how best to capture remodel opportunities. Although not indicated, lost opportunities also occur with new construction in the industrial sector. However, new expansion is not itemized in the forecasting methodology and there is no method to identify lost opportunities in advance.

2.6. Innovative Technology

For the most part, the technical potential is based on current technology. This is a conservative assumption. If the past is any indication, there will be dramatic improvements and cost reductions in efficiency products. However, at this stage, it is difficult to include in program planning new products which are likely but not currently available. This will be an important future direction of our work.

At the urging of the advisory group, some new technology options have been considered in the technical potential. A "high tech" refrigerator is an efficiency option for the future. It shows up as contributing to the high technical potential in the year 2012 for appliances. However, the programmatic savings currently reflect only the current energy saving products.

This does not begin to exhaust the possible technological improvements. Vast changes are currently underway in the field of lighting. However, at this time, new technology is not included in lighting measures. This is because current products included in the supply curves, when considered in programs, absorb a major portion of the lighting enduse potential. The remaining potential to be addressed by new products is still significant but not as large. It is expected that lighting innovations will be included during subsequent upgrades of the spreadsheet planning tools.

2.7. Background Conservation

Although it is only an approximation, consumer barriers can be treated as if they were purely financial. This is done by assuming a high implicit consumer discount rate of about 60% consistent with expected payback observed in consumer market studies. The high discount rate allows the cost-effectiveness calculations to predict the "gravity" amount -- the amount of conservation that people would have done anyway even without a utility program. That amount is low. Generally a measure must have a levelized cost of about 8 mills/KWh to be attractive to consumers. Only a few options, such as efficient lighting, meet this requirement.

The models have been run with the high discount rate to see how much conservation consumers would do on their own. That amount would have happened even without any conservation program. It can also be considered an estimate of the maximum potential of "free riders", persons who received a utility incentive for something they would have done anyway. Thus, an estimate of expected free ridership needs to be subtracted from the program outcome to give the net effect. In most cases, however, the free ridership is small. Consumers are not interested in programs unless the savings are extremely cheap.

Table 4 -- Cost Induced Conservation Technical Potential
Average Megawatts in year 2012 at 8 mills/KWh or less
Based on Medium High Forecast, Merged Company

Sector	Existing Stock	New Construction	All Stock
Residential	1.1 MWa	0	1.1 MWa
Commercial	64.0	142.3	206.3
Industrial	---	---	---
Total	65.1	142.3	207.4 (10% of technical potential)

Table 4 lists an estimate of the conservation that consumers would do on their own. Outside of solar access, there are no low-cost opportunities in new residential construction not incorporated in building codes. (The amount of solar access in existing practice was included in the basecase.) The largest amount of such conservation occurs in commercial sector. That is because there are many low-cost options. At least some of the customers should recognize those opportunities. Industrial sector is not included in this table because industrial "background" trends are already included in the econometric forecasting model.

2.8. Net Energy Savings

The actual energy savings of utility programs may be less than estimates due to customer takeback and background conservation. Evidence is lacking to clarify precisely these impacts.

Customer takeback occurs when customers choose to take some of the energy savings in the form of increased comfort levels rather than lower energy bills. For example, after a house is weatherized, the customer sees a lower electric bill. They may choose to set up the thermostat, open previously closed rooms and otherwise increase energy consumption. This may be a partial explanation for why observed energy savings are less than predicted. However, other explanations are also possible. It may be that the prediction method was in error or that the installation was incomplete.

Conservation evaluations from Hood River were intended to clarify the actual amount of energy savings. Unfortunately, clear results were not obtained. Changes in the economic level of the community make it difficult to compare before- and after-weatherization usage. A recent analysis of Pacific's weatherization savings indicated only minor deviation for expected savings in the aggregate. The Regional Council's forecasting model predicts about 30% reduction in consumption due to economic elasticity in existing residential space heating. A derating of engineering estimates consistent with the 30% reduction was done before calibrating Pacific's residential sales data to the engineering estimates. Otherwise savings estimates were not explicitly reduced for takeback.

Background conservation is another consideration. Technical potential is estimated relative to an assumed "frozen" efficiency energy forecast. That is, the forecast of energy demand assumes that customers continue to consume energy at the current relative rate. (exceptions are included for appliance standards and codes where

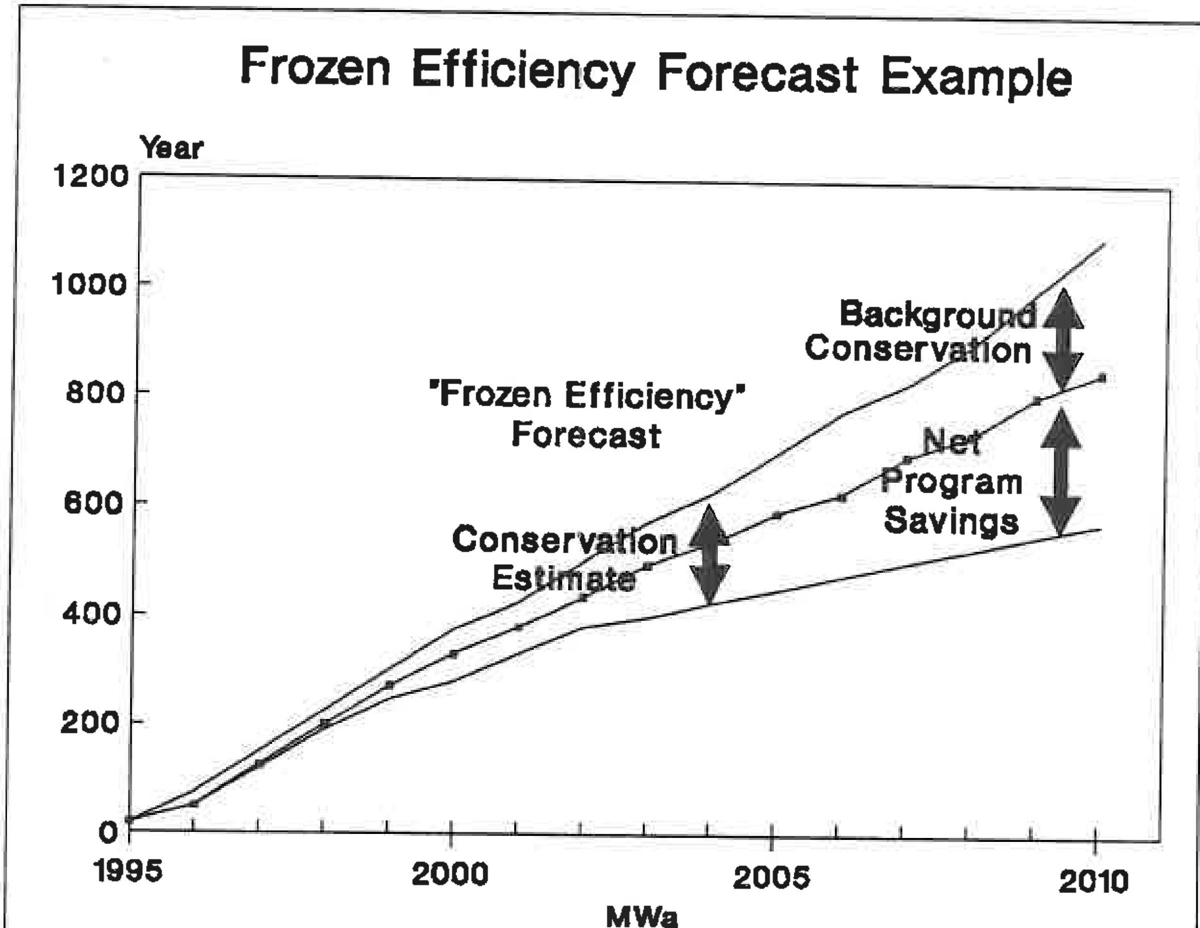

Figure 3 Frozen Efficiency Illustration

mandated efficiency standards are known.) Conservation potential is measured relative to this continued usage level. To forecast energy demand in the absence of utility programs, the background amount must be subtracted from the frozen efficiency forecast. To forecast energy usage with utility programs, the programmatic savings are subtracted from the frozen efficiency forecast. Thus, from the utility's point of view, the difference in demand is the difference between these two forecasts. Stated another way, the net energy savings are the programmatic savings minus the background conservation that would have occurred anyway. This technique is illustrated in Figure 6.

This method of calculating net savings assumes that a certain amount of customers accepted the utility incentives to do what they would have done anyway. These are referred to as "free riders". Generally, utilities try to minimize free riders because they dilute the effectiveness of incentives. There are also "free drivers", that is, person who are influenced by the program or by availability of products without accepting a utility incentive. Free drivers counter the effect of free riders. In general, it is difficult to determine the amount of free riders or free drivers in programs.

For purposes of Least Cost Planning, the procedure has been to first estimate all gross programmatic savings, including those savings taken as increased comfort. Gross savings also includes savings due to background conservation and market transformation benefits. The amount of gross savings is then used to calculate the Total Resource Cost (TRC) representing the society perspective. Then the estimate is reduced to net energy savings (after subtracting takeback and background) to calculate the utility's financial parameters. Resources are selected in approximately the order of increasing TRC, but the design and operation of programs may be constrained by financial impact on the utility.

3. Design of Demand-Side Programs

3.1. Identifying Opportunities

When it comes to planning programs, neither the summary table nor the combined supply curve are useful. The supply curve combines information from so many different sources that a specific application gets lost. Another graphic technique is useful. A two-dimensional map is one way to keep track of where the savings are located by sector and conservation measure. The maps assist program planning. Opportunity maps were prepared for RAMPP-1. The maps were not updated but are expected to still be representative of RAMPP-2 conditions.

The technical potential is only the first step in developing demand-side programs. The potential shows where programs should be targeted for maximum effect, where opportunities lie and what some interactions may be. Now the applicable conservation measures must be combined into workable programs. The next two sections discuss some of the issues and concerns in planning programs. The resulting set of program options is presented in Section 4.

3.2. Issues in Program Design

3.2.1. Consumer Barriers

Critics have wondered why the utility needs to be involved in redirecting energy investments. They suggest that the marketplace should be capable of finding its own direction through pricing mechanisms. They are reasons why this is not the case. Regulatory-controlled prices may not provide proper signals to consumers. Far more significant are major barriers and market imperfections. These barriers are partly financial, since consumers do not have access to capital at the long-term rates available to utilities. In addition, there is a cost to the individual decision maker to include energy consideration in decisions that already include a number of factors. Consumers don't often consider energy decisions as investment decisions. There are costs to gather the information needed to do so. Furthermore, in many market segments, the equipment purchaser, the bill-payer and the enduser are different people with very different motivations. Effective programs will be a marketing challenge. It will be necessary to understand participant's motivations and to tailor program offerings for maximum acceptance.

Another consumer problem is that only the most cost-effective purchases are likely to attract consumer interest. If consumers proceed, they may invest only in a part of the purchase. This leads to "cream-skimming" where only the most attractive options are considered. The danger is that other options, only slightly less attractive, might be overlooked. These other options would be cost-effective if done together, but not if a separate job is required. Thus, cream-skimming may create lost opportunities. Utility assistance can remove some of the market barriers and facilitate better conservation.

3.2.2. Need for Evaluation

The planning study is only as good as the information on which it is based. Often our knowledge is sketchy and incomplete. One of the tasks for the immediate future is to refine the planning tools and assumptions. Pilot programs serve a dual function. They allow implementation techniques to be tested. And they test assumptions about the end-uses, opportunities and resource availabilities. Conservation programs in the next few years, such as lost opportunity programs, will include an explicit evaluation component for refining planning assumptions and implementation details.

3.2.3. Timing and Ramping Rate

Conservation programs are often thought to be short lead time, able to be started and stopped as desired. In fact, there are constraints. Conservation is dependent on the perspectives of consumers, equipment suppliers and others. The programs will not succeed if programs are changed too often. Contractors cannot stay in business if program rates vary excessively. Thus, there are minimum viable levels necessary to maintain programs in an operational mode.

At the other extreme, there are constraints on how rapidly a large-scale program can be deployed. Suitable personnel need to be trained. Administrative costs may be difficult to control as programs become larger and more complex. Generally higher programs rates will cost more. Thus, there is a maximum ramp up rate as well. Somehow the programs need to be managed so that the industry stays viable during the surplus. Then the industry needs to be sufficiently developed for ramp up when the surplus ends.

Assume, for illustrative purposes, that a decision is made to achieve all available conservation by about the year 2000. It takes several years to build up to a high level. Even at the maximum rate, it takes years to complete full acquisition. Much of the work during the first five years can be done in advance and then banked for a later decision on rampup. Additional flexibility can come through spreading the major acquisition phase over longer or shorter time periods, although this may have some impact on unit costs.

3.2.4. Rate Impact and Equity

To the extent that conservation acquisition requires substantial funding, it can create a paradox. Although the conservation may be cheaper than new generation and lower total revenue requirement (and thus average bills for customers), it can still increase unit electricity prices. This is because of lost revenues. The company relies on customer payments to meet fixed expenses, such as paying for the transmission lines or previously constructed facilities. When some customers reduce purchases through conservation, prices must increase to provide the same amount of net revenue and cover the added conservation costs. Note that total costs will go down, so customers as a whole are better off. However, the people who benefit from an individual program and those who face higher prices are not necessarily the same. While conservation participants see reduced bills, non-participants could see increased bills. This becomes the central equity issue -- is everyone treated fairly?

The Company focuses on reducing total cost to serve all customers. (In technical terms, the Company does not focus on the no-losers test.) This does not mean that equity considerations are ignored. There are several options. If the utility operates multiple large programs, there can be some benefit for all -- everyone a participant in something. To some extent the utility can lower the funding requirement by finding innovative ways to package a broader service to participating customers and thus recover program costs directly. The rate impacts can also be limited to the customer class which contains the predominant beneficiaries.

Concern for equity needs to taken in context. The current rate structure, by necessity, cannot produce perfect equity. The equity impacts caused by a broad conservation acquisition program may be small. Thus, before implementing a mechanism to ensure equity, one needs first to assess the problem as one looks at the equity impacts of an integrated plan.

3.2.5. Energy Service Charge

The concept of Energy Service Charge is a response to equity concerns. There is an acknowledgement that non-participants should not be unnecessarily burdened. Moreover, there is recognition that conservation is a valuable service for which customers should expect to pay something. Therefore, it seems reasonable that participants should reimburse non-participants by returning a portion of their savings. The exact form and amount of that reimbursement has still to be decided.

The Energy Service Charge is imagined to be an additional service charge added to the billing meter. As such, it would stay in place regardless of who operates the facility until it is fully paid off. This service charge has the advantage of minimizing administrative costs. The utility provides the customer with full up-front financing, offering the benefit of the utility's longer time perspective on payback. The customer retains a portion of the savings so that they have positive cash flow. There are alterative possibilities for the repayment amount. It could be a flat charge, like a low-interest loan payment. It could be a billing for saved kilowatt-hours, in which case it would increase as prices increase. Billing for saved kWh is a difficult concept to explain to participants. More recent design have focused on a low-interest loan approach.

3.3. Program Design Considerations

3.3.1. Significant Delivery Capability

The technical potential is an upper bound engineering estimate of the resource. The portion of that resource that can actually be realized is a function of program design and intentions. Generally demand-side programs have involved independently targeted programs with little consideration of how the programs relate. The broad analysis of technical potential that we now have provides a reference allowing assessment of programs designed as an integrated package to address the whole resource.

As part of a 20 year plan, the programs must be characterized by a reliable delivery capability both for quantity and time of delivery. At this stage of the process, prior to integration, we do not know the "slot" that conservation will need to fill. However, we need a set of programs to begin the interactive process of finding the least cost mix. We have, therefore, begun our program construction around a scenario that would call forth a broad front of programs capable of capturing the majority of the technical potential. To establish this option, the programs must have "significant delivery capability", that is, the programs will be specified to deliver 65% of the technical potential in a program duration of 7 years.

From a traditional marketing standpoint, this is an ambitious objective. Typical marketing objectives are to increase market penetration by a few percent in a year or to achieve market penetrations of the order of 20% in several years. By contrast, the marketing goals of effective demand resource programs will be of the order of 20% market penetration PER YEAR. This is fast track marketing! Such marketing involves substantial innovation, sustained incentive levels, high public exposure for the company, personal contact with most of the customers and involvement in the community planning process to optimize company activity.

3.3.2. Implementation

Underlying the design of all programs in this scenario are the principles of minimizing lost opportunities and ensuring low income participation.

Programs should specifically address the lost opportunities created in new construction or in new appliance purchases. Programs should not create lost opportunities in the course of the program operation. Lost opportunities occur when a program addresses only a few of the most cost effective measures, leaving the less cost-effective, but still viable measures. These measures will then be lost because they cannot justify the expense of an additional site visit.

The Company has committed to assure that low income customers are equally represented. In practice, this means that the proportion of low income participants relative to all participants must be at least as great as the proportion of low income customers to all customers. This commitment, applicable in the residential sector, requires that at least 22% of the participants in residential programs be low income customers.

3.3.3. Planning and Timing

Program planning proceeding from the technical potential estimate begins with an overview perspective on the entire level of program activity. This perspective can improve program efficiency by minimizing redundancy and maximizing helpful program interactions. The necessity for multiyear program planning is reinforced by pilot and rampup requirements of about 5 years for most programs.

Most programs operate in an environment dominated by yearly construction cycles. The full effect of any particular incentive or other program feature will require more than one yearly cycle to be integrated into the plans of the prospective participants. Program efficiencies associated with cumulative program recognition or with increased operation efficiencies will be evident only after program operation of at least three years.

3.3.4. Cost Control

A large demand-side program will involve hundreds of thousands of small transactions. There is potential for significant cost savings through economies of scale. On the other hand, there is potential for cost overruns through inadequate program oversight or planning. A primary cost control check lies in an explicit evaluation component in each program. Evaluation tracks cost-effectiveness and actively guides the evolution of improved effectiveness. Anticipating a high level of program activity mandates consideration of several cost control issues early in the design phase.

Selection of Eligible Measures

Each program consists of a "bundle" of conservation measures subject to the constraint that no single measure have a levelized cost greater than a cost effective ceiling. This constraint prevents "luring" a program participant into an investment which cannot be justified as less costly than the alternative. Several conservation measures, for example, high quality storm windows or heat pumps, will have additional value to the participant for other reasons than energy savings. In this case, the program would need to distinguish between the energy-justified and amenity-justified portions of the measure cost.

Cost Share

All conservation measures confer benefits on the program participants and on the utility system as a whole. Ideally, equity is served when the participant shares his portion of the costs. But the necessity for the program in the first place stems from the fact that the participant was unable to or unwilling to make the investment. It is apparent that the penetration of the program will bear closely on the level of cost share, the quality of the marketing and program innovations. While precise information relating the penetration to the participant contribution is not available, some estimate of the interaction between cost sharing and market penetration must be made initially. In fact, the actual cost share required will need to be an output of the early experience of every pilot program. The strategy used in this scenario is to start at the upper end of the utility cost share range and to reduce the utility cost share based on results from the pilot projects. An alternative of assuming a significantly smaller utility requirement can be examined later as an alternative scenario.

Program Synergies

The requirement of significant delivery capability means that several programs will be operating simultaneously. Programs designed as a package offer opportunities to consolidate and reduce costs through "piggybacked" operations. Program marketing will be enhanced by the visibility that one program can have on another.

Learning Curve and Large Scale Benefits

Some program areas, notably residential weatherization and retrofit lighting will involve hundreds of thousands of replications. Learning curve theory suggests that the costs can be reduced after the first large number of initial projects. However, experience with crash programs does not show a price reduction when programs are forced into production at a high rate. Programs can access learning curve price reduction by careful attention to the bidding structure and to an ongoing program evaluation/improvement component.

Market Transformation

All programs operate in an environment that is changing. This environment consists of several major infrastructures: program participants, contractors, suppliers, government and designers. Programs involving new construction involve all these infrastructures. If any one of them is not supportive, then program activity is significantly reduced. Conversely, when all the infrastructures have integrated the program then the market has been successfully transformed. The utility program is no longer necessary. A new construction code is an example of a mandated market transformation. The savings potential in market transformation lies in the fact that a sufficiently aggressive program now can eliminate the need for a program in the future. Other examples of market transformation occur with specific products. Near term programs may include some measures, such as efficient lighting or VSD motors, which are somewhat expensive now. However, there is good reason to believe that significant cost reductions can result if a market for these products develops. When that happens the new products will tend to become the standard for all new installations. Thus, including some of these expensive measures in early years, may create "free" savings in later years as the market transformation takes place.

3.3.5. Lost Program Opportunities

From the previous discussion, it is clear that programs must be aware of lost opportunities. They must be operated such that they do not create lost opportunities. There are also lost program opportunities to consider. These are cases where outside funds exist for potential cost sharing or co-sponsorship. There is no guarantee that these funds will be available later. Failure to utilize the program opportunity could mean that the utility will face higher costs later. An example may occur in low-income weatherization. There are currently some government agencies with available funds, such as oil overcharge funds. By "piggybacking" on these opportunities and drawing co-funding into elective conservation, the utility can operate a more efficient program at a lower total cost. But the opportunity must be utilized quickly.

3.3.6. Quality Control/ Program Evaluation

Demand side programs are, by nature, diffuse. They involve thousands of independent actions. Program plans operate on fundamental assumptions of penetration rates, physical barriers and costs. The achievement of cost and penetration targets will require an explicit and timely evaluation component. Evaluation must be closely enough integrated with program operations and planning that it can accomplish the following:

a. Establish work and materials specifications updated yearly.
b. Provide monthly tracking reports on program progress vis-a-vis program plans.
c. Provide the capability for program evolution, mid course corrections, trouble shooting and general problem solving.

d. Establish an impact evaluation methodology and associated databases for credible yearly certification of program outputs.
e. Provide a yearly process evaluation with respect to general program effectiveness and participant satisfaction and motivation.
f. Identify marketable spinoff opportunities.
g. Provide feedback on demand side planning assumptions.

3.4. Strategic Program Development

From the previous discussion, it is clear that the kinds of program offerings need to be significantly different from programs which the Company has operated in the past. The development of these program innovations is described here as strategic development. The requirement for significant capability means that programs will need to be capable of ramping up to a sustained activity level much larger than any previous programs. A full resource deployment would be the equivalent of operating 40 Hood River Projects per year for over five years. The requirement to operate the programs cost effectively requires that new and effective management. The programs will have to manage a multitude of small, dispersed installations and do so with minimal administrative cost. At the same time, a high level of quality must be assured. The programs will be leaner and smarter than any previous programs. New technical and managerial tools and procedures must be developed. The process will require some expenditure on development in early years. It will also require effective and timely evaluation feedback to capture learning curve improvements. It is important to assure that pilot programs have sufficient budget for these critical foundation tasks of development and evaluation.

4. Demand-Side Program Options

The demand-side programs in this section have been developed with the previously described considerations in mind. The program set is intended to capture a significant portion of the technical potential. This program activity divides naturally into two basic phases, the lost opportunity/ pilot phase and the acquisition phase. During the lost opportunity/pilot phase, lost opportunities are secured and pilots conducted. These activities position the Company to undertake the acquisition phase to capture the major portion of the resource.

Timing of these programs deserves special mention. It is assumed for the purpose of this scenario that pilots/lost opportunity programs start in 1991. The other programs represent optional or schedulable conservation. Although pilots can be started earlier to provide flexibility, the acquisition phase will be implemented only when new resources are needed and when any cheaper resources have already been utilized. One of the outcomes of this planning process will be to define the extent that a full range of lost opportunities can now be undertaken consistent with prudent business practice given the current financial and operating environment. Determination of the timing for schedulable resources will be the outcome from the later integration phase of the Least Cost Plan. At this time, the exact date that acquisition will start has not been determined. For illustration, we assume that acquisition will start in 1996. Working backward, this means that pilots should be completed and rampup phase should be occurring by 1994. Pilot programs then need to have started by about 1990, in order to provide useful results in time for rampup.

The following section describes conservation programs included in the Least Cost Plan. Capability building is recognized as a strategy to manage uncertainty and risk. The programs focus on lost opportunities and pilot testing of schedulable conservation programs. At some point, probably around 1995, the company will need to make a decision as to scheduling of conservation acquisitions. If growth is expected to be high, all programs would be ramped into full-scale acquisition. If growth is expected to be medium, only the relatively low-cost programs would proceed. If growth is expected to be low, conservation would continue to be deferred. An example is shown in Figure 4 to illustrate the capability building stage in the near term and the context within a long term acquisition scenario.

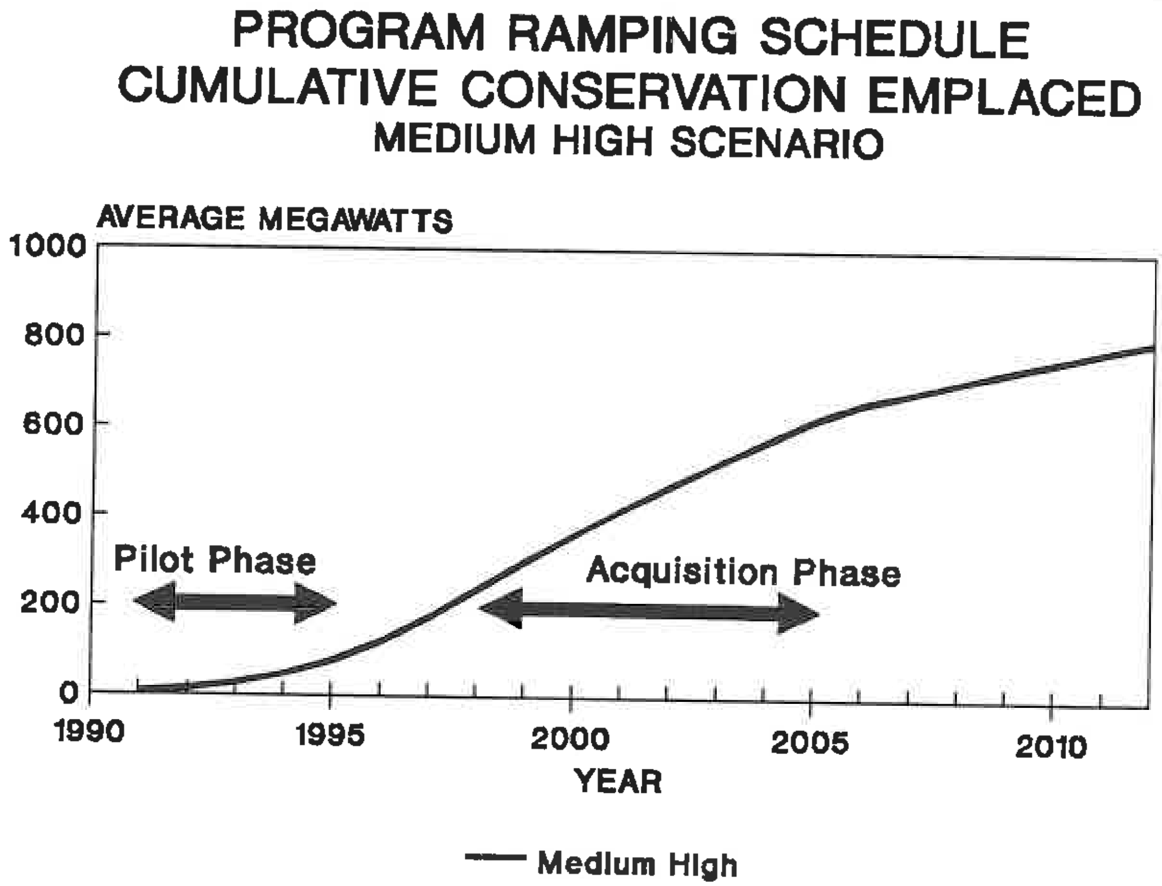

Figure 4 Program Ramping Medium High Scenario

The lost opportunity/pilot phase makes use of the current surplus to develop capability. The goal is to create cost-effective program options which can be applied later during the acquisition phase. The acquisition phase, to be operated later, has an average gross utility cost of the order of $70 million/year. It could be executed optionally as a net revenue enhancement under suitable regulatory, power supply and wholesale energy price conditions. These programs also show the power of the market transformation where efficient new construction continues to deliver conservation even after the utility program has ended.

A brief summary of each program is given below. A detailed program description including year by year cost and yield estimates follows in Section 5.

Table 5 -- Major Resource Acquisition Programs Medium High Scenario 1991- 2011
** Acquisition Programs Based on Need for Resource in 1996 **

PROGRAM	PHYSICAL GOAL	RESOURCE YIELD IN 2011 UTAH MWa	%	TOTAL LEVELIZED RESOURCE COST MILLS/KWh	UTILITY COST MILLS/KWh	LEVELIZED PROGRAM COST MILLIONS '91 $	GROSS UTILITY KEY FEATURES
LIGHTS & WATER HEATER APPLIANCE RETROFIT	300,000 homes	28	36	23	17	62	Lights, appliances in homes without electric space heat
RESIDENTIAL RETROFIT	155,000 homes	56	36	27	8	235	Cost share via energy service charge weatherization
INDUSTRIAL	300 plants	375	52	26	0	1099	Technical assistance utility finance
NEW COMMERCIAL	76,000 buildings	140	46	28	5	1000	On-going lost opportunities program utility finance
NEW RESIDENTIAL	176,000 homes	53	11	31	26	348	Long term program in addition to MCS includes manufactured homes
COMMERCIAL RETROFIT	43,000 buildings	129	31	40	-1	615	Cost share via energy service charge utility finance
ALL PROGRAMS		781	43	26	4	3359	

Table 6 -- Demand Side Resources By Economic Growth Scenario in Year 2011

Energy Savings By Program	Low Forecast		Med-Low Forecast		Med-High Forecast		High Forecast	
	MWa	TRC	MWa	TRC	MWa	TRC	MWa	TRC
Appliance Retrofit	2	23	15	23	28	23	28	23
Residential Weatherization	56	28	56	29	56	27	56	27
Industrial	174	28	258	27	375	26	471	26
New Commercial	59	31	96	30	140	28	155	29
New Residential	19	32	35	31	53	31	69	31
Commercial Retrofit	125	29	129	31	129	31	129	32
Total	435	21	588	29	781	26	910	28

Demand Savings By Program	Low Forecast		Med-Low Forecast		Med-High Forecast		High Forecast	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
Appliance Retrofit	3	3	24	24	46	46	47	47
Residential Weatherization	102	23	103	23	91	20	91	20
Industrial	290	290	430	430	625	625	785	785
New Commercial	91	71	148	115	216	169	239	187
New Residential	28	10	52	19	78	29	102	37
Commercial Retrofit	207	148	214	154	215	154	215	154
Water Heater Load Control	191	115	213	128	213	128	225	135
Total	914	660	1183	892	1484	1170	1705	1365

4.1. Summary Program Descriptions

The Company's Least Cost Planning process uses a set of hypothetical or "draft" programs to estimate how demand-side and supply-side resources can be integrated together. The sum of these programs is shown for four economic growth scenarios in Figure 5. The programs can be divided into lost opportunities, which depend primarily on the economic growth assumed, and scheduled programs, for which the ramp rate can be timed. Lost opportunities under the four scenarios are shown in Figure 6. Scheduled program ramping is shown in Figure 7.

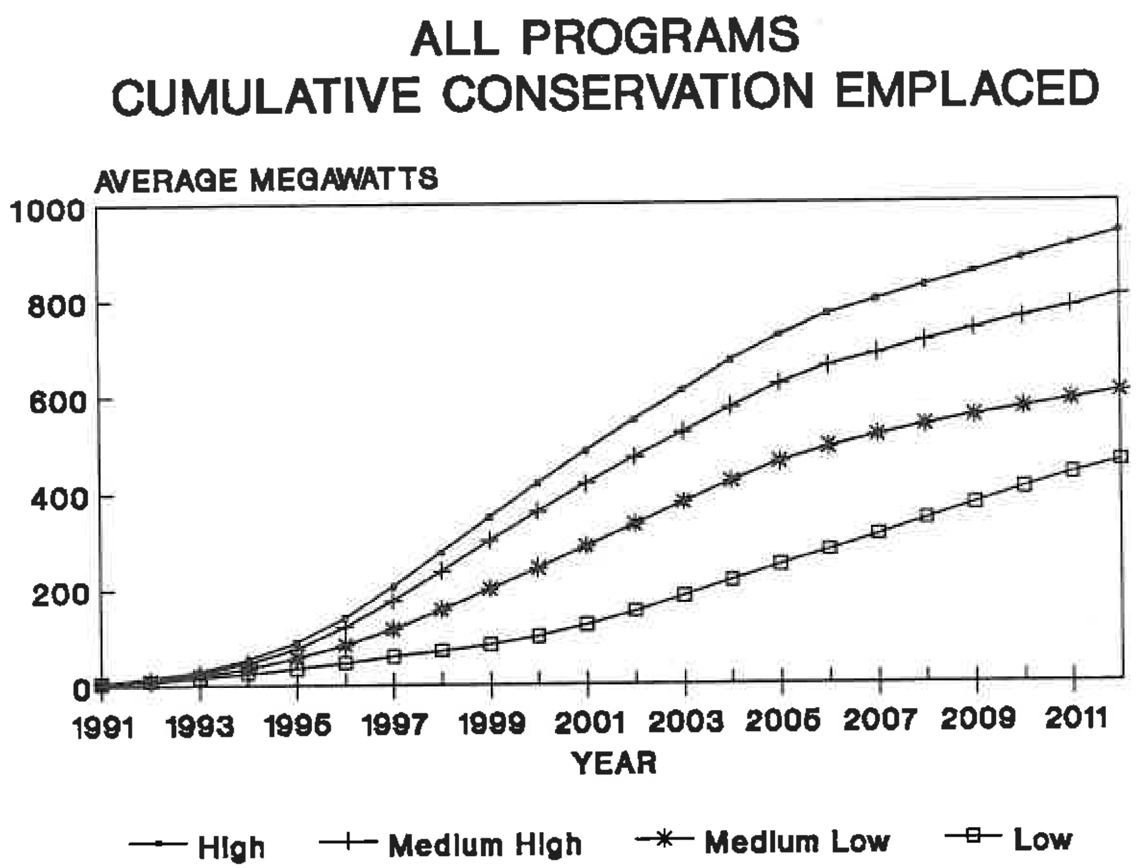

Figure 5 Four Economic Scenario

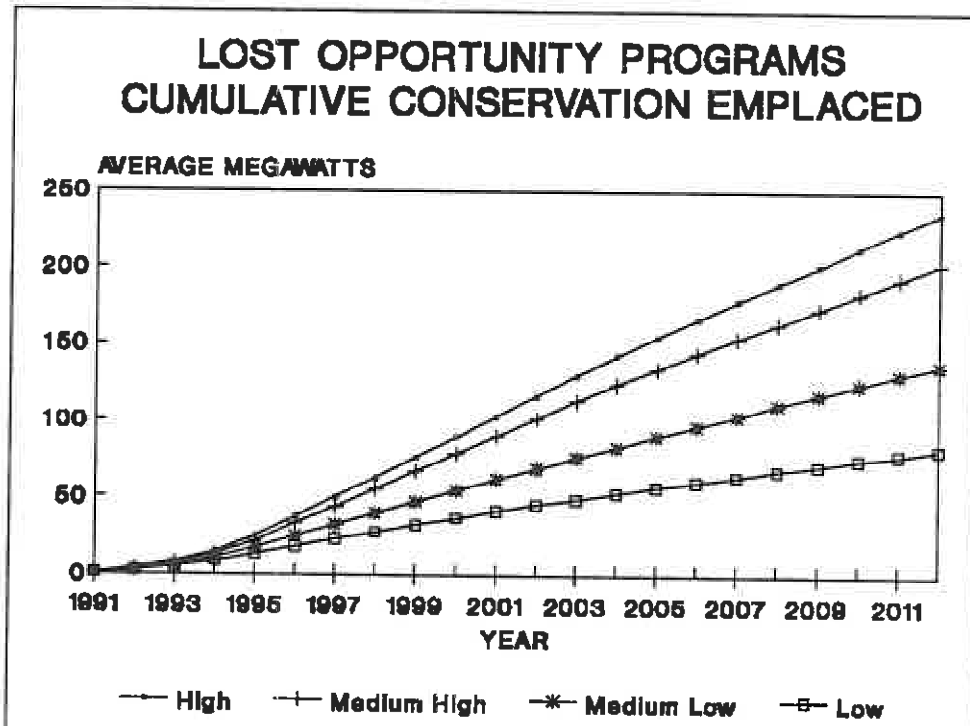

Figure 6 Lost Opportunity Programs

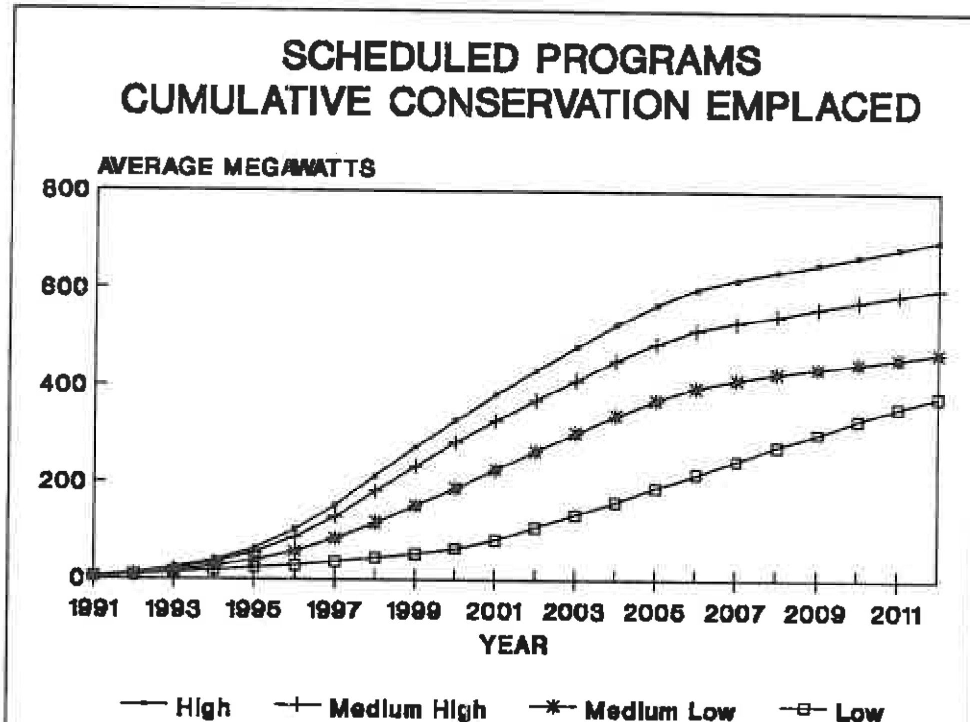

Figure 7 Scheduled Acquisition Programs

4.1.1. Industrial

This program seeks a strong liaison between the Company and industrial customers. the Company's current economic development role in new industrial is augmented to include the financing of electrical efficiency measures. The program tests and refines the "energy service charge" mechanism to implement a cost share relationship with no upfront cost for the customer. As currently planned, the financing will be at about the utility's cost of capital. Interest rate on the loan does not appear to create participation hurdles since the participants will receive other benefits in improving production processes. The program will develop a series of horizontal program offerings for industrial niche areas. Examples might include air compressor efficiency, lighting and HVAC, or efficient motors. The strategy is for the niche programs to serve as an entry for additional process efficiency improvements. The program also develops an industrial sector least cost information base. Data will assist with apportionment of the resource into

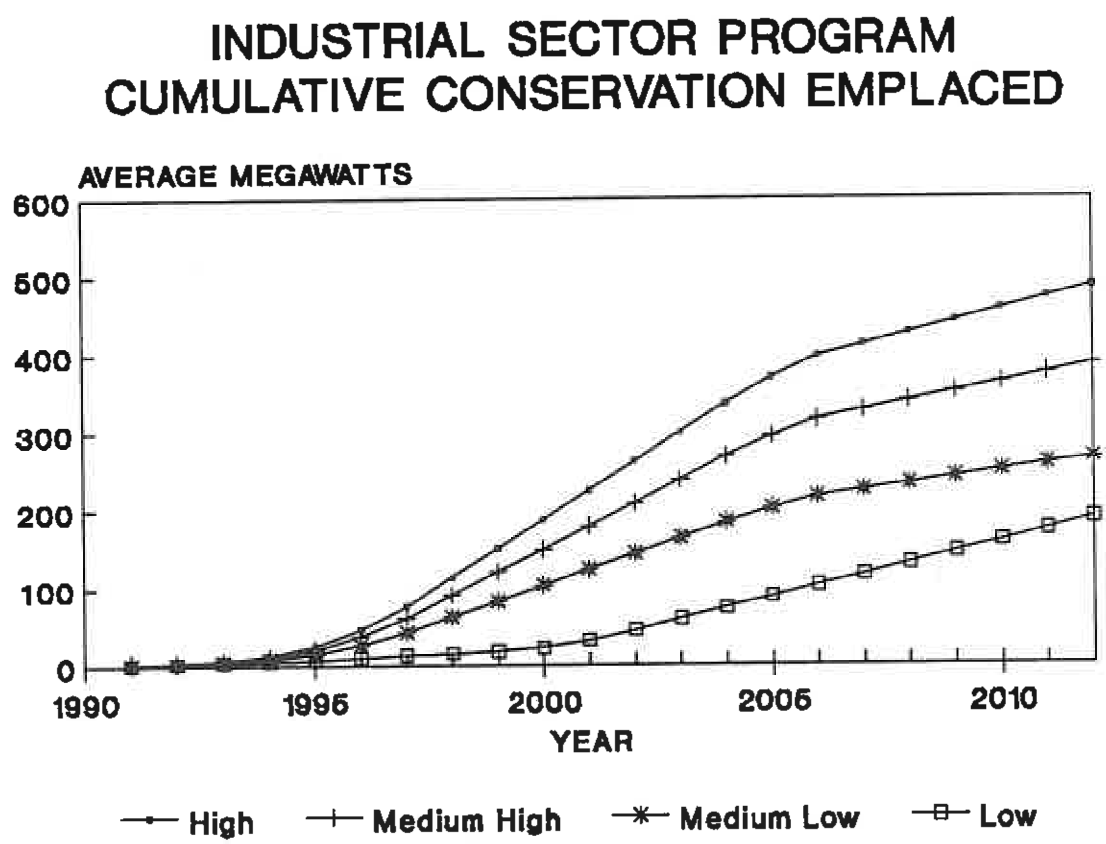

Figure 8 Industrial Sector Programs

schedulable and lost opportunities components. The industrial pilot is also intended to have a market transformation benefit through accelerating the trend in industrial electrical efficiency.

Program activity level is highly influenced by the economic growth assumed. Much of the increase in forecast load comes from industrial sector, consequently there are more opportunities for savings with high growth rates. Ramping of the program is treated as a scheduled resource. The amount of resource under the four economic scenarios is shown in Figure 8.

4.1.2. New Commercial Construction

This program, run from 1992 on, addresses lost opportunities by accelerating the energy efficiency transformation in new commercial construction. New commercial construction includes major remodels. A design incentive of approximately $.20/sq.

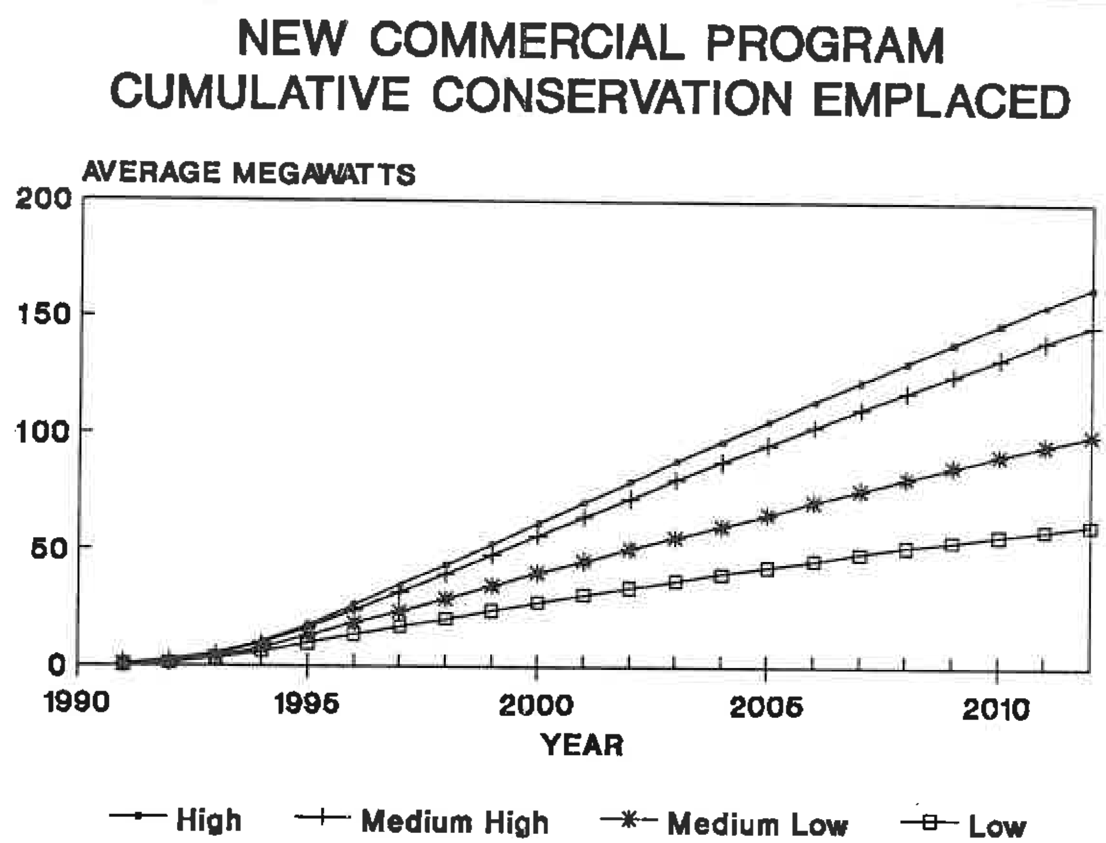

Figure 9 New Commercial Sector Programs

ft. and installation financing of approximately $1.00/sq. ft. are offered to qualifying new commercial construction. Financing assistance is the primary incentive for participants. The supply, design and economic development communities are intensively networked to identify eligible projects and to reinforce the market transformation. Emphasis on this market transformation is essential to establishing the base of experience and consensus necessary for an improved commercial code. Even with a market transformation, the commercial MCS code upgrade scheduled for 1992 is expected to capture only about 40% of the identified technical potential. This is because of the technical complexities of implementing a commercial code. The remaining savings are expected to be cost effective enough to justify a long term program in the 1995-2010 time period, with the utility's role and incentive levels to be defined on the basis of the actual realized code.

Program activity level is primarily a function of the economic growth assumed, since the program ramps up rapidly to target 85% penetration. Program resource under the four economic scenarios is shown in Figure 9.

4.1.3. Commercial Retrofit Pilot

This program would run 5 years prior to the estimated need for acquisition, or as assumed here, starting in 1991. It is operated as a high profile event in a medium-sized city typical of Pacific's territory (Albany, Oregon). In this sense, it is similar to a commercial sector version of the Hood River Project. The program objective, a comprehensive retrofit of a major portion of the commercial space, tests the viability of accessing a broad spectrum of commercial customers. This pilot also helps to validate or refine Pacific's least cost planning model for the commercial sector. The retrofits will be on the basis of a utility cost share with the customer portion secured by an "energy service charge" on the meter. This pilot also develops the capability for audit and quality control management of a commercial retrofit program. A associated objective of this pilot will be to assure that retrofit lighting is superior to original in terms of quality and function and to explore the viability of a separate business service associated with advanced lighting technology and energy-related O&M services. A critical development task will be building the technical and managerial tools needed for large-scale deployment. The mature program must provide low-cost auditing, installation supervision and savings verification for thousands of small jobs. Program activity is similar in all the economic growth scenarios. Resource amounts are shown in Figure 11.

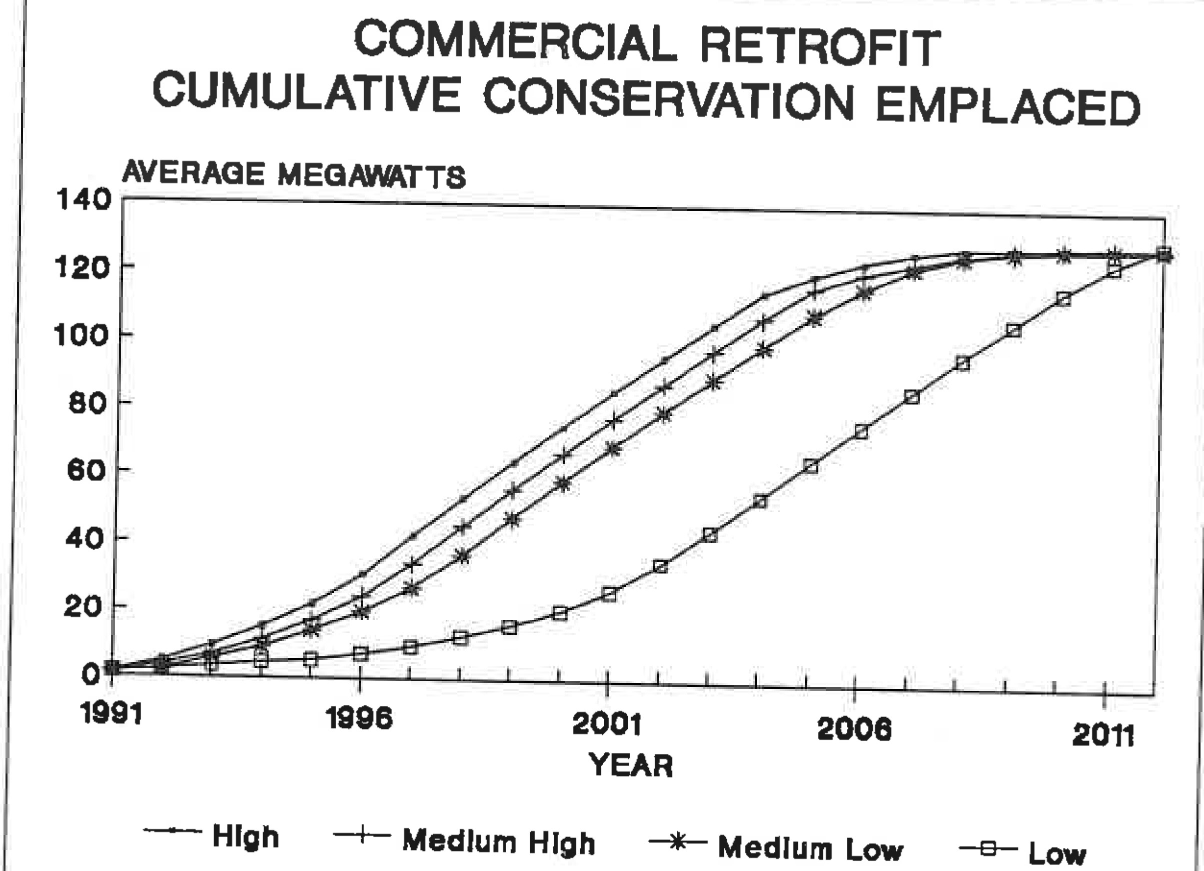

Figure 10 Existing Commercial Programs

4.1.4. Residential Retrofit Pilot

There are two components of this program. The low-income program would operate immediately (1992 - 1995) and take advantage of potential cost-sharing opportunities. The pilot residential program will commence 5 years prior to the estimated date that acquisition would be required. As a residential program is developed, it will absorb existing loan programs. Together, both components maintain and strengthen residential retrofit capability by supporting a broad community cost share low-income weatherization program and by piloting a positive cash flow program to other customers.

The low income component would produce low income participation by offering $1200 toward the costs of full weatherizations to be matched by other funding sources. An additional low-income program will seek contractors with a bidding process.

The non-low income pilot would test a "energy service charge" repayment of a low-interest loan against the meter of the weatherized home to secure the customer's cost share. This arrangement has no up-front cost to the customer and may represent a significant utility cost reduction to customers with high electric heating use. The pilot will maximize program benefits during early development stages. Development will focus on improved tools and procedures to improve the ability to accurately estimate savings, manage installations and supervise the program.

Important research questions include verifying planning assumptions and the delivery mechanism. The Company's previous experience consists of the Hood River Program. This program operated successfully but not cost-effectively. It

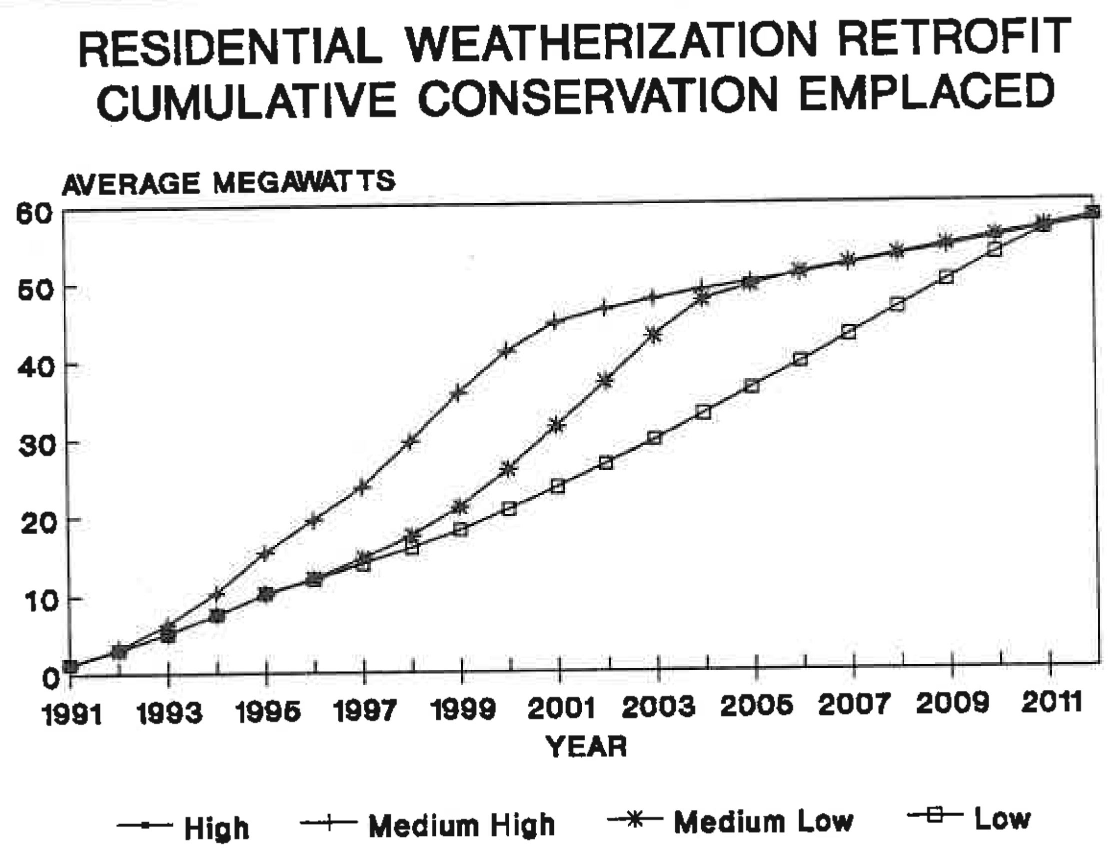

Figure 11 Existing Residential Programs

remains to be seen how such a program can be managed to deal with all the logistics, management and coordination problems efficiently. In addition, the ability to successfully persuade customers to participate in large numbers needs to be tested. The pilot program will operate initially in Washington and California. The Washington program anticipates delivering a free home energy audit and some simple conservation measures (low flow showerhead). Half the recipients are targeted to accept a full weatherization package with Company-provided financing. This high activity level is shown under the High and Medium High scenarios in Figure 11. Under Medium Low scenario, the program would ramp more slowly. Under the Low scenario, the program would operate at a minimum viable level which brings in the resource slowly over 20 years.

4.1.5. New Residential Construction

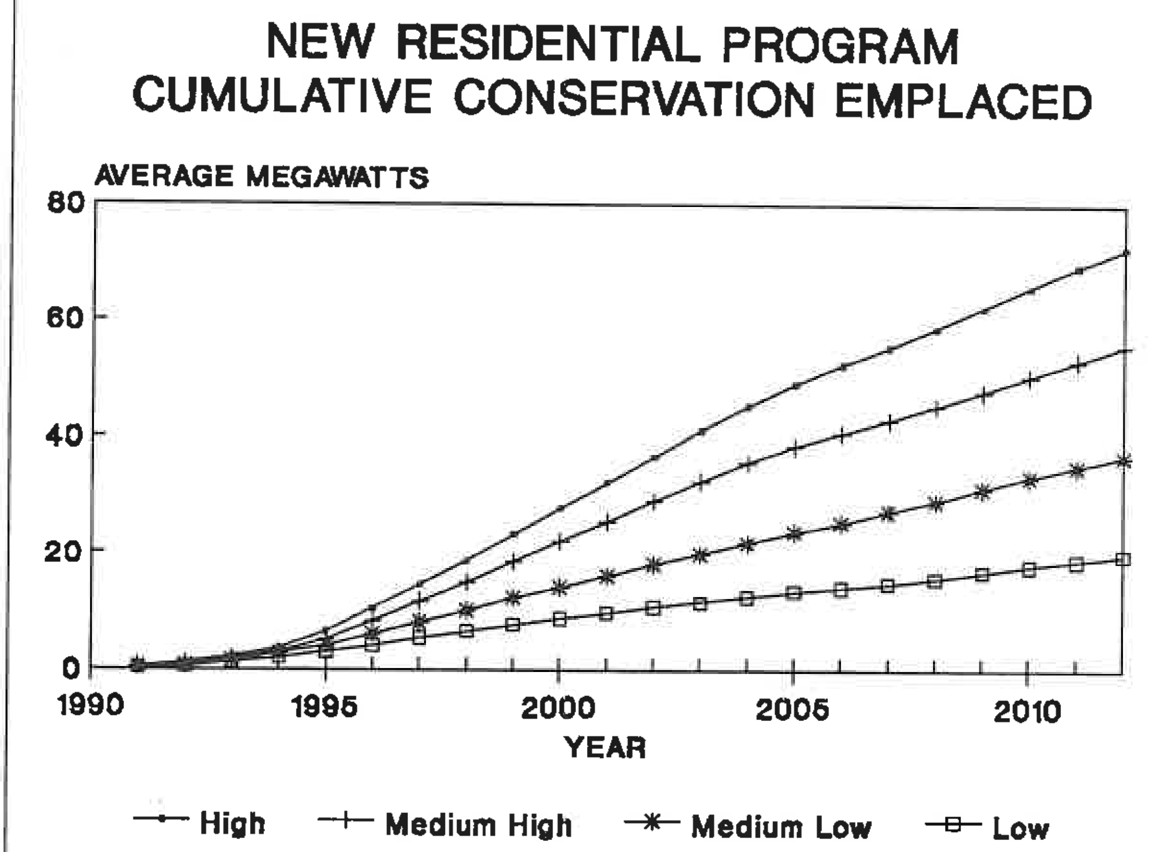

Figure 12 New Residential Programs

This program, run from 1992 on, addresses lost opportunities by accelerating the efficiency transformation in new residential construction. The four-year Super Good Cents program intended to achieve 60% penetration by 1992. However, codes have been adopted in Oregon and Washington. A Long Term Super Good Cents program is being planned to continue the capture of cost effective opportunities beyond the new building codes. The Long Term Program is enhanced to include solar orientation and daylighting. Emphasis is placed on stimulating the home buyer of the 1990's.

The manufactured home component is addressed by supporting the Residential Conservation Demonstration Project (RCDP) demonstration of MCS mobile homes and advocating strong HUD standards be implemented in 1994. The Company expects to participate in a manufacturer's acquisition program. Under this program, utilities in the Region would pay an incentive to manufacturers for efficient units. Manufacturers would change assembly practices so that all units are efficient. Because the incentive is paid at the manufacture level before dealers markup costs, it achieves high impact with minimal cost. The strength of this demonstration program is expected to drive the HUD standards process, minimizing utility costs in the long term.

Program activity is dictated by the economic growth assumed. Penetration targets are expected to ramp up rapidly to high levels. The Super Good Cents program expects to get 85% penetration. The Long Term program, following new building codes, will have a more difficult time reaching high penetration targets. Program resource under the four growth scenarios is shown in Figure 12.

4.1.6. Appliance Retrofit

This program, run as an acquisition program in the late 1990's, shows a high community profile. As a retrofit measure, it addresses an estimated 150,000 to 250,000 customers who can benefit from compact fluorescent lighting, a water heater wrap and/or improved shower fixtures. This program develops or purchases in bulk high quality products and installs them with trained personnel. The customer's 50% cost share (about $30) would be recovered through a one time charge. Financing for other measure offerings, such as solar water heaters, can be included for appropriate family sizes and in appropriate climate zones.

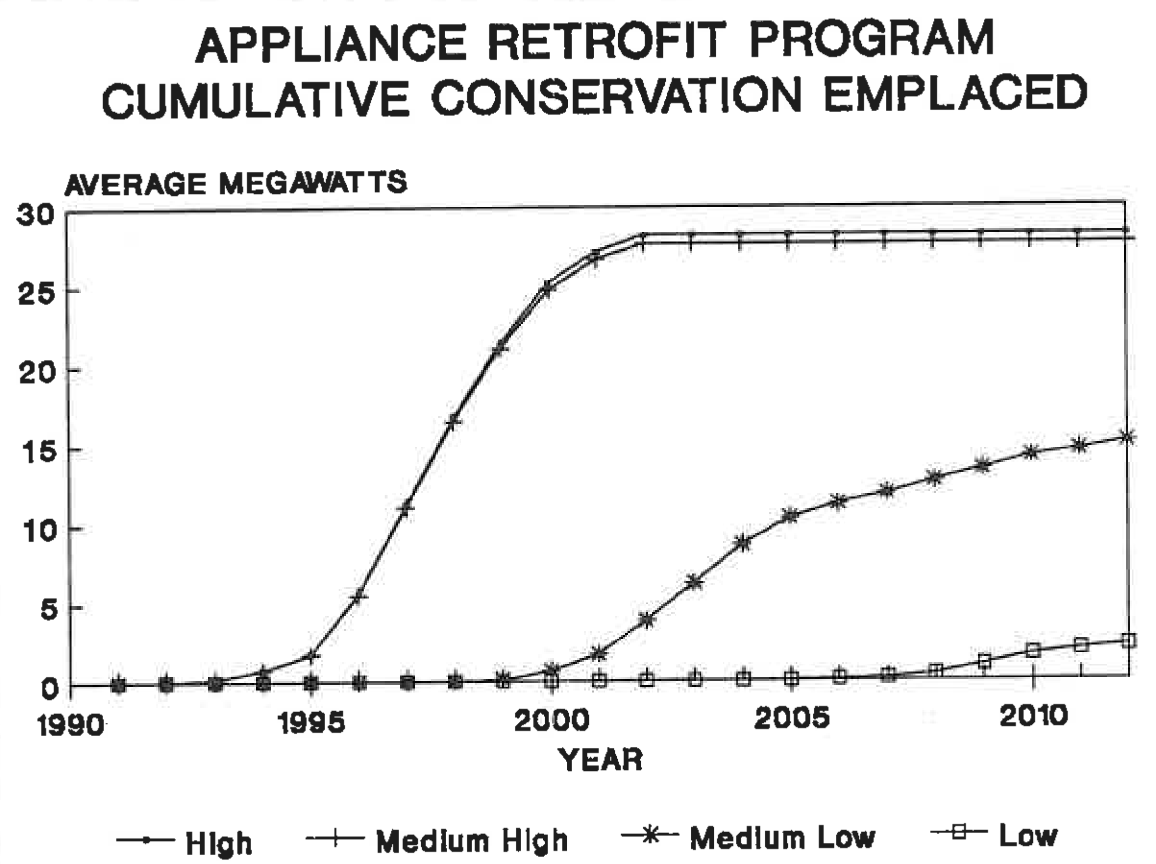

Figure 13 Appliance Programs

The amount of savings from this program is small, although the cost is inexpensive. This program reaches a large number of customers, including those without electric space heat, but savings per home are small. Program activity behaves in an unusual manner on growth assumptions. Under High or Medium High growth, the program would take place early. Under Medium Low, it would be delayed and under Low delayed even longer. Delay means that there are fewer untreated appliances for the program to address. This is because the older appliances are being retired and replaced with more modern ones. This change is included in the forecast. As a result, this program would probably not be considered under a Low growth case. Program resource under the four scenarios is shown in Figure 13.

This program has the potential to be expanded to include other types of appliances. A large technical potential has been identified for the appliance sector. Unfortunately, the efficient appliances assumed for the supply curves are not yet available in large numbers on the local market. It is expected that ideas for an appliance program will be refined as more information becomes available. For that reason, this program may be more appropriately viewed as a place-holder for new appliance ideas.

4.1.7. Water Heater Load Control

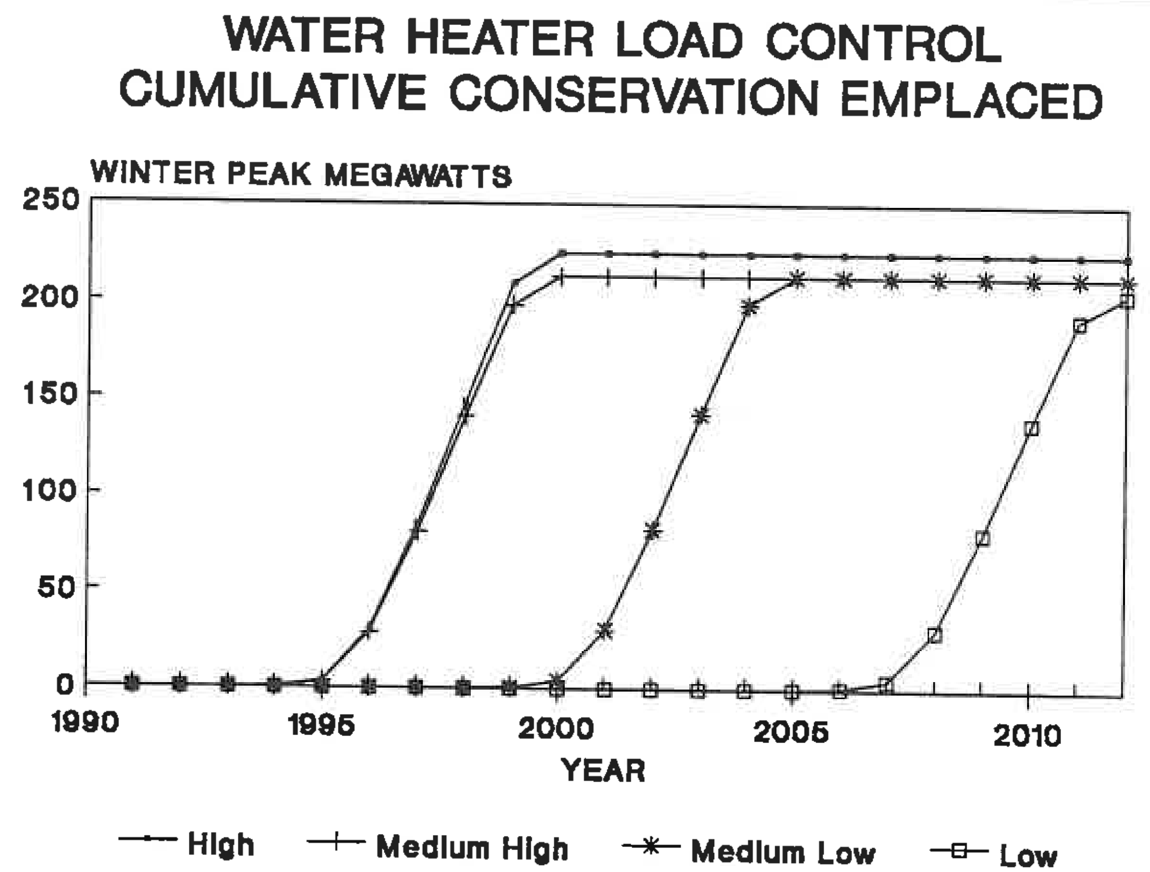

Figure 14. Water Heater Load Control Programs

An offshoot of the appliance program is directed only at demand savings. Water heater load controllers are an example of potential load control options. This program would pay participants an incentive to accept load control on their water heater. The program would be implemented in the late 1990's, as need for additional capacity becomes apparent. The program assumptions are as follows: installation cost is $250/unit for materials and labor to install stand-alone timing devices on water heaters. These devices will shut off the water heater during system peak times. As stand-alone devices, they do not depend on radio signals. Repair and replacement cost is assumed to be $70 after 10 years. Participants receive $24/year ($2/month) reduction on their electric bill for their cooperation. Capacity savings are estimated here as 1 kW in winter and 0.6 kW in summer.

4.2. Administrative Cost

Planning for Demand-Side programs must include administrative costs as one component of the Total Resource Cost (TRC). Regional planning has tended to increase TRC by applying a fixed percentage of measure cost as an added administrative cost. Typically the cost of conservation programs is assumed to increase by 20% for administration.

Our planning approach is different. Explicit costs are estimated for administrative cost components. The net increase in TRC is often lower than 20%. There are several reasons for this difference.

First, the uniform percentage of added cost fails to recognize different levels of measure cost across programs. For example, residential sector measures cost more than commercial sector conservation. Thus, similar program costs in residential sector should be a smaller percentage of a larger number. On the other hand, in appliance programs the same administrative cost would be a high percentage because the measure cost is low.

Second, the assumption of high administrative cost may be true for programs in the initial stage of development. Initial programs contain large marketing and evaluation components. However, as programs become mature, the proportional share of these costs can be expected to decrease. Our long-term program planning anticipates market transformation and program synergies to occur. This means that the programs can be operated in the out years with proportionally smaller administrative outlays.

The following table shows the administrative cost components and TRC. The administrative percentage is calculated as an adder to the simple measure cost. Measure cost is not defined in precisely the same way in each program. For example, the new commercial program includes design cost as part of the measure cost. The commercial retrofit program includes audit/design work as part of the administrative adder. The residential programs include a variety of program mechanisms. Table 7 shows overhead for a weatherization program with full financing. Low Income and partial loan programs would be different because the Company only pays part of the measure costs.

It should be pointed out that these costs represent hypothetical programs for planning purposes. The actual budgeting decisions for these program areas will be determined subsequently.

Table 7 -- Long Term Program Administrative Cost

Program	Yield MWa	Deferred Percentage	Expense Percentage
Industrial		4%	1%
New Commercial		29	1
Commercial Retrofit		20	1
Residential Retrofit		30	1
New Residential		NA	
Appliance		30	5
Load Control		15	5

4.3. Programmatic Supply Curve

The conservation programs need to be considered in context. There are synergies and interactions between programs. For example, operating several programs at the same time allows some overlap in staff and marketing efforts. This reduces administrative costs. On the other hand, operation of a "cream-skimming" program would prevent capturing all the potential savings. This is because, after installing the cheapest measures, it would no longer be cost-effective to go back a second time for installing other measures. Thus, blocks of conservation savings cannot be added together quite like supply-side options.

Nevertheless, for illustrative purposes, Figure 14 shows the programs as if they were combined in a demand-side resource stack. The illustration gives an idea of how the programs compare in terms of magnitude. One must be careful in use of this programmatic supply curve because it does not address issues of timing. For

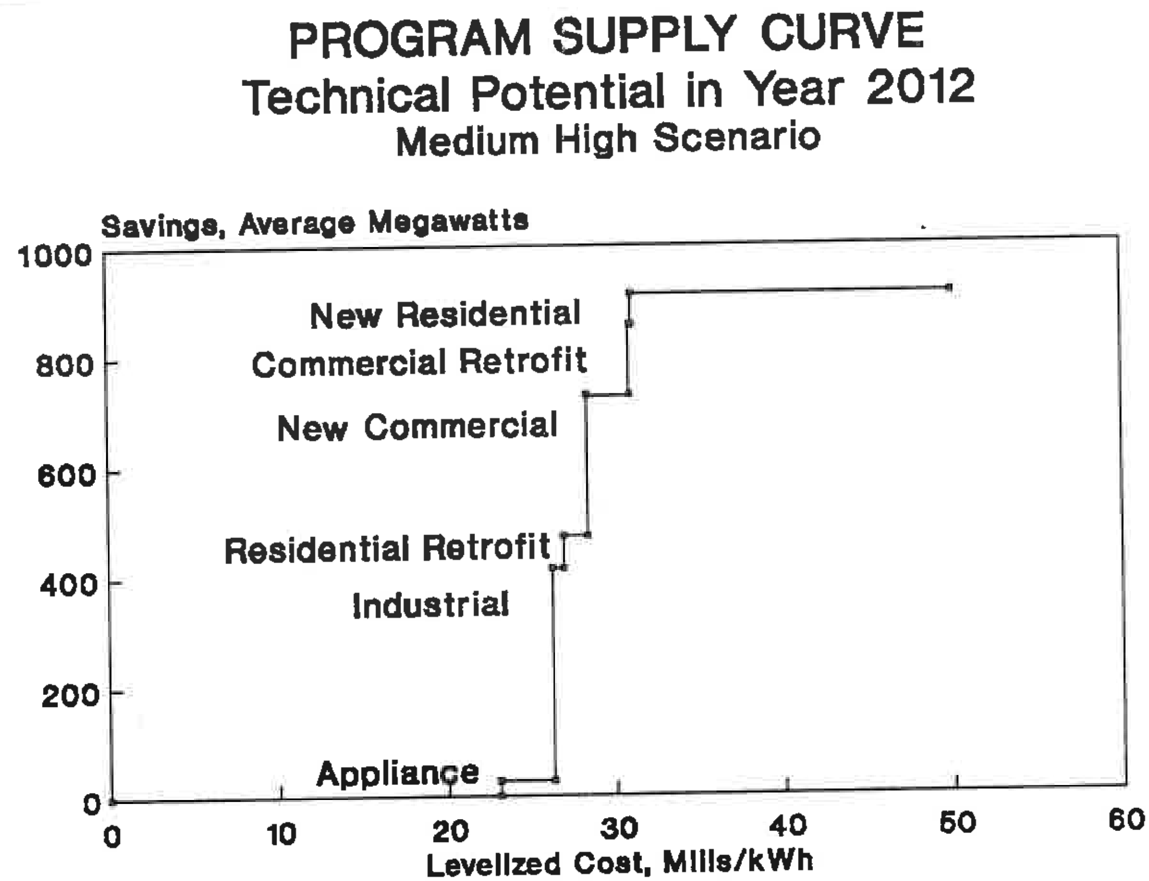

Figure 15 Programmatic Supply Curve

example, it would appear that a program for existing residential buildings would be implemented before a program for new buildings based on cost. But the new buildings represent lost opportunities if they are ignored. Therefore, the order in which programs are implemented cannot be based merely on cost considerations. Cost differences for complete programs appear to be minor. Most of the programs are estimated to cost around 30 mills/kWh.

4.4. From Technical Potential to Programmatic Potential

This section looks at the transition from technical potential to programmatic potential. What assumptions were made along the way? What decrements in potential occurred as a result?

The transition is computed as follows. Start with the technical potential. Add line losses to estimate gross potential. Multiply by the effective penetration rate to get gross program potential. Subtract "free riders", if any, for net program potential. Examples are shown in Table 8. There are some problems disaggregating the residential sector savings. The programs include space heat and appliances melded together such that separation is difficult. The example below shows shell and appliances separated with effective penetration rates of the programs. These penetrations are slightly different from those shown in the draft program worksheets. In this table, the penetrations are energy-weighted. In the worksheets, they were based on number of participants.

Table 8 -- From Technical Potential to Programmatic Potential

Sector	Technical Potential +	Line Loss =	Gross Potential X	Effective Penetration =	Gross Program -	Free Riders =	Net Program
Existing Coml.	240	+ 10.5%	= 265	X .65	= 172	- 42	= 129
New Coml.	329	+ 10.5%	= 364	X .70	= 255	- 108	= 147
Industrial	527	+ 6%	= 563	X .69	= 387		= 387
Existing Resid.	67	+ 12%	= 75	X .65	= 48		= 48
New Resid.	99	+ 12%	= 111	X .47	= 52		= 52
Appliance	107	+ 12%	= 120	X .40	= 52		= 48

4.5. Near Term Action Plan

The final step in the planning process is a major jump -- from academic planning scenarios to real-world programs. So far in the process, the discussion has described the "draft" program plans. These are somewhat hypothetical programs developed as Demand Side Resources for use in the integration studies, assuming typical planning scenarios. The draft programs are designed to be as realistic as possible, understanding that they are based on future scenarios which are themselves hypothetical constructions for planning purposes. The draft programs stretch for the entire twenty year planning horizon, even though it is not possible to know the future with any degree of certainty. Thus, the draft programs show the types of program direction but should not be expected to represent any hard-and-fast commitment to one specific future path. Dealing with the future as it unfolds will require a degree of flexibility.

Although the long-term future may be uncertain, one can describe the general policies expected to guide future programs. And during the very near term (the next two years) one can be specific about the programs goals. Based on RAMPP-2, the Company expects two general policies: (1). Aggressively pursue opportunities that might otherwise be lost. (2). Develop the capability to be able to acquire major conservation resources after the mid 1990's.

The building of capability will be acquired by vigorously pursuing lost opportunities and by ramping up conservation acquisition programs so that they will be poised for full deployment when needed. To accomplish this, a series of specific program goals have been developed for the next two years as listed in Table 9.

The table lists estimated energy and peak savings as well as estimated budget. For programs that depend on new construction, the energy estimate is not the important goal. This is because the amount of energy savings will vary with the amount of economic growth that occurs. A more important goal for new construction is penetration rate. For unit goals, recognize that the units are not the same in all sectors. In residential sector, unit goals are number of homes or participants. In commercial sector, unit goals are in thousands of square feet of buildings. In industrial sector, unit goals are in MWh.

Table 9. Near Term Action Goals by State

SUMMARY
PLANNED DSR ACTIONS

		Units	Energy MWa	Peak MW	Budget k$
1992	OREGON				
	Residential Loans	1,348	0.4	0.3	$587
	Appliances		0.3	0.4	$217
	Residential WX	0	0.0	0.0	$0
	Low Income WX	1,085	0.3	0.2	$2,312
	Resid. Retro. Subtotal	2,433	1.0	0.9	$3,116
	New Residential	390	0.3	0.5	$3,121
	New Commercial	2,811	1.1	2.7	$3,083
	Commercial Retrofit	1,258	1.1	1.7	$2,168
	Industrial	9,636	1.1	1.8	$1,955
	Incremental Total		4.6	7.6	$13,443
1993	OREGON				
	Residential Loans	1,348	0.4	0.3	$587
	Appliances		0.3	0.4	$228
	Residential WX	1,300	0.7	0.6	$3,586
	Low Income WX	1,085	0.3	0.2	$2,312
	Resid. Retro. Subtotal	3,733	1.7	1.6	$6,713
	New Commercial	3,947	2.6	2.7	$6,887
	New Residential	520	0.4	0.6	$2,417
	Commercial Retrofit	2,078	1.6	2.4	$5,059
	Industrial	8,950	0.9	1.5	$3,157
	Incremental Total		7.2	8.8	$24,233
	Cumulative Total		11.8	16.4	$37,676

Table 9. Near Term Action Goals by State

SUMMARY PLANNED DSR ACTIONS		Units	Energy MWa	Peak MW	Budget k$
1992	WASHINGTON				
	Residential Loans	70	0.1	0.1	$115
	Appliances		0.1	0.1	$44
	Residential WX	933	0.3	0.4	$2,571
	Low Income WX	369	0.2	0.1	$718
	Resid. Retro. Subtotal	1,372	0.6	0.7	$3,448
	New Residential	130	0.1	0.2	$509
	New Commercial	466	0.3	0.5	$542
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	3,000	0.3	0.6	$600
	Incremental Total		1.4	2.0	$5,099
1993	WASHINGTON				
	Residential Loans	70	0.1	0.1	$115
	Appliances		0.1	0.1	$46
	Residential WX	1,552	0.9	0.7	$3,999
	Low Income WX	369	0.2	0.1	$718
	Resid. Retro. Subtotal	1,991	1.2	1.0	$4,878
	New Commercial	747	0.5	0.6	$1,063
	New Residential	390	0.3	0.5	$601
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	4,946	0.5	0.8	$1,284
	Incremental Total		2.4	2.8	$7,826
	Cumulative Total		3.8	4.8	$12,925

Table 9. Near Term Action Goals by State

SUMMARY PLANNED DSR ACTIONS		Units	Energy MWa	Peak MW	Budget k$
1992	CALIFORNIA				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$9
	Residential WX	150	0.1	0.1	$565
	Low Income WX	202	0.0	0.0	$157
	Resid. Retro. Subtotal	352	0.1	0.1	$730
	New Residential	52	0.0	0.1	$255
	New Commercial	111	0.2	0.3	$126
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	1,650	0.2	0.3	$384
	Incremental Total		0.5	0.8	$1,495
1993	CALIFORNIA				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$9
	Residential WX	400	0.1	0.1	$775
	Low Income WX	202	0.0	0.0	$157
	Resid. Retro. Subtotal	602	0.2	0.1	$941
	New Commercial	188	0.2	0.2	$397
	New Residential	130	0.1	0.2	$283
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	2,100	0.2	0.4	$733
	Incremental Total		0.7	0.9	$2,354
	Cumulative Total		1.2	1.7	$3,849

Table 9. Near Term Action Goals by State

SUMMARY PLANNED DSR ACTIONS		Units	Energy MWa	Peak MW	Budget k$
1992	IDAHO PP&L				
	Residential Loans	41	0.0	0.0	$59
	Appliances		0.0	0.0	$9
	Residential WX	0	0.0	0.0	$0
	Low Income WX	4	0.0	0.0	$5
	Resid. Retro. Subtotal	45	0.1	0.0	$73
	New Residential	52	0.0	0.1	$55
	New Commercial	0	0.0	0.0	$129
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	0.0	0.0	$0
	Incremental Total		0.1	0.1	$257
1993	IDAHO PP&L				
	Residential Loans	41	0.0	0.0	$59
	Appliances		0.0	0.0	$9
	Residential WX	0	0.0	0.0	$0
	Low Income WX	4	0.0	0.0	$5
	Resid. Retro. Subtotal	45	0.1	0.0	$73
	New Commercial	62	0.2	0.2	$114
	New Residential	52	0.0	0.1	$51
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	0.0	0.0	$0
	Incremental Total		0.3	0.3	$238
	Cumulative Total		0.3	0.4	$289

Table 9. Near Term Action Goals by State

SUMMARY PLANNED DSR ACTIONS		Units	Energy MWa	Peak MW	Budget k$
1992	IDAHO UP&L				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$3
	Residential WX	0	0.0	0.0	$0
	Low Income WX	173	0.0	0.0	$20
	Resid. Retro. Subtotal	173	0.0	0.0	$23
	New Residential	52	0.0	0.1	$193
	New Commercial	97	0.0	0.1	$116
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	0.0	0.0	$0
	Incremental Total		0.1	0.2	$332
1993	IDAHO UP&L				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$3
	Residential WX	0	0.0	0.0	$0
	Low Income WX	173	0.0	0.0	$20
	Resid. Retro. Subtotal	173	0.0	0.0	$23
	New Commercial	162	0.2	0.2	$244
	New Residential	130	0.1	0.2	$169
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	0.0	0.0	$0
	Incremental Total		0.3	0.4	$436
	Cumulative Total		0.4	0.5	$768

Table 9. Near Term Action Goals by State

SUMMARY PLANNED DSR ACTIONS		Units	Energy MWa	Peak MW	Budget k$
1992	MONTANA				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$12
	Residential WX	0	0.0	0.0	$0
	Low Income WX	107	0.0	0.0	$30
	Resid. Retro. Subtotal	107	0.0	0.0	$42
	New Residential	52	0.0	0.1	$108
	New Commercial	0	0.0	0.0	$5
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	0.0	0.0	$0
	Incremental Total		0.1	0.1	$155
1993	MONTANA				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$13
	Residential WX	0	0.0	0.0	$0
	Low Income WX	107	0.0	0.0	$30
	Resid. Retro. Subtotal	107	0.0	0.0	$43
	New Commercial	124	0.2	0.2	$241
	New Residential	130	0.1	0.2	$97
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	0.0	0.0	$0
	Incremental Total		0.3	0.4	$381
	Cumulative Total		0.3	0.4	$536

Table 9. Near Term Action Goals by State

SUMMARY PLANNED DSR ACTIONS		Units	Energy MWa	Peak MW	Budget k$
1992	WYOMING PP&L				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$0
	Residential WX	0	0.0	0.0	$0
	Low Income WX	0	0.0	0.0	$0
	Resid. Retro. Subtotal	0	0.0	0.0	$0
	New Residential	13	0.0	0.0	$101
	New Commercial	0	0.0	0.0	$0
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	0.0	0.0	$0
	Incremental Total		0.0	0.0	$101
1993	WYOMING PP&L				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$0
	Residential WX	0	0.0	0.0	$0
	Low Income WX	0	0.0	0.0	$0
	Resid. Retro. Subtotal	0	0.0	0.0	$0
	New Commercial	534	0.5	0.6	$1,205
	New Residential	130	0.1	0.2	$109
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	1.0	0.0	$521
	Incremental Total		1.6	0.7	$1,835
	Cumulative Total		1.6	0.8	$1,936

Table 9. Near Term Action Goals by State

SUMMARY PLANNED DSR ACTIONS		Units	Energy MWa	Peak MW	Budget k$
1992	WYOMING UP&L				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$0
	Residential WX	0	0.0	0.0	$0
	Low Income WX	0	0.0	0.0	$0
	Resid. Retro. Subtotal	0	0.0	0.0	$0
	New Residential	52	0.0	0.1	$7
	New Commercial	0	0.0	0.0	$0
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	0	0.0	0.0	$50
	Incremental Total		0.0	0.1	$57
1993	WYOMING UP&L				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$0
	Residential WX	0	0.0	0.0	$0
	Low Income WX	0	0.0	0.0	$0
	Resid. Retro. Subtotal	0	0.0	0.0	$0
	New Commercial	32	0.1	0.1	$60
	New Residential	52	0.0	0.1	$5
	Commercial Retrofit	0	0.0	0.0	$0
	Industrial	1,973	1.2	0.4	$971
	Incremental Total		1.3	0.5	$1,036
	Cumulative Total		1.4	0.6	$1,093

Table 9. Near Term Action Goals by State

SUMMARY PLANNED DSR ACTIONS		Units	Energy MWa	Peak MW	Budget k$
1992	UTAH				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$0
	Residential WX	0	0.0	0.0	$0
	Low Income WX	300	0.1	0.1	$900
	Resid. Retro. Subtotal	300	0.1	0.1	$900
	New Residential	52	0.0	0.1	$254
	New Commercial	2,131	0.6	1.9	$878
	Commercial Retrofit	308	0.2	0.3	$236
	Industrial	6,000	0.7	1.1	$1,234
	Incremental Total		1.7	3.5	$3,502
1993	UTAH				
	Residential Loans	0	0.0	0.0	$0
	Appliances		0.0	0.0	$0
	Residential WX	300	0.2	0.1	$905
	Low Income WX	300	0.1	0.1	$900
	Resid. Retro. Subtotal	600	0.3	0.3	$1,805
	New Commercial	1,964	1.3	1.1	$3,907
	New Residential	130	0.1	0.2	$257
	Commercial Retrofit	2,216	1.7	2.6	$6,278
	Industrial	9,879	1.1	1.9	$2,762
	Incremental Total		4.6	5.9	$15,009
	Cumulative Total		6.2	9.4	$18,511

Table 9. Near Term Action Goals by State

SUMMARY
PLANNED DSR ACTIONS

		Units	Energy MWa	Peak MW	Budget k$
1992	TOTAL				
	Residential Loans	1,459	0.5	0.4	$761
	Appliances		0.4	0.5	$294
	Residential WX	1,083	0.4	0.5	$3,136
	Low Income WX	2,240	0.7	0.6	$4,141
	Resid. Retro. Subtotal	4,782	2.0	1.9	$8,332
	New Residential	844	0.7	1.0	$4,603
	New Commercial	5,616	2.2	5.4	$4,879
	Commercial Retrofit	1,566	1.3	2.0	$2,404
	Industrial	20,286	2.3	3.9	$4,223
	Incremental Total		8.5	14.2	$24,440
1993	TOTAL				
	Residential Loans	1,459	0.5	0.4	$761
	Appliances		0.4	0.5	$308
	Residential WX	3,552	1.9	1.6	$9,265
	Low Income WX	2,240	0.7	0.6	$4,141
	Resid. Retro. Subtotal	7,251	3.5	3.1	$14,476
	New Commercial	7,760	5.6	5.9	$14,118
	New Residential	1,663	1.3	1.9	$3,989
	Commercial Retrofit	4,294	3.3	5.0	$11,337
	Industrial	27,848	5.0	4.9	$9,428
	Incremental Total		18.7	20.9	$53,348
	Cumulative Total		27.2	35.1	$77,788

5. Draft Program Scenarios

Notes on Draft Programs

The following sheets show summaries of the programs assumed under different planning scenarios. There are certain conventions applied:

All costs are shown in real dollars.

Levelized cost is calculated on an "instant cost" basis, as if the program were all implemented in one year. Average annual ESC revenue, if it applies, is calculated on the same instant cost basis.

Levelized cost is computed from the NPV of the investment. As described in Section 2.2.2, program cost is assumed to be deferred expense. This provides a tax benefit which reduces program cost.

Industrial Program

The Industrial Program assume an ESC financing rate of 8%. That rate is lower than the current Energy Partners program. Administrative cost is 4% and 1% of measure cost. Measure cost includes contractors cost to handle audits, design and installation. As a reality check, the expected savings work out to about 10% of sales.

New Commercial

This program assumes as ESC finance rate of 9%, which is similar to Energy FinAnswer. Administrative overhead is 29% deferred and 1% expense. This overhead includes essential features such as design modeling, commissioning and verification of savings. Both gross and net savings are tracked. Net savings are reduced for the amount of "background conservation" already assumed in the forecast. This sector has the largest amount of assumed "background". Capacity savings are calculated using a conservation load factor derived from computer modeling as discussed in the Supply Curve documentation. As a reality check, the savings are estimated to be 14% of net sales.

Commercial Retrofit

This program assumes as ESC finance rate of 9%, which is similar to Energy FinAnswer. Direct measure costs include a 19% adder for audit and design. Administrative overhead is an additional 20% deferred and 1% expense. This overhead includes essential features such as commissioning and verification of savings. Both gross and net savings are tracked. Net savings are reduced for the amount of "background conservation" already assumed in the forecast. Capacity savings are calculated using a conservation load factor derived from computer modeling. As a reality check, the savings are estimated to be 25% of net sales.

Residential Retrofit Programs

There are currently several programs directed at residential weatherization. The program assumption is that Low Income weatherization will continue as capability building. The Company is committed to maintaining a proportional share of Low Income as a customer service. Due to the high amount of takeback, Low Income weatherization is not a cost-effective resource. A new weatherization program is imagined to absorb elements of the existing programs. The new program would be directed at a high participation rate, incorporating recent knowledge of how to improve the effectiveness of weatherization.

New Residential

Residential programs are difficult to model because of the diversity of enduses and uncertainty concerning future programs. In this case, Super Good Cents is assumed to ramp up to the expected 85% level in Idaho and Montana. Those savings are then assumed in the forecast. Likewise, the new MCS codes in Oregon and Washington are assumed in the forecast. The program then consists of an expanded Super Good Cents program in Wyoming and Utah, a Long Term Super Good Cents in the Northwest and California and the manufactured home acquisition program. The Long Term program is expanded beyond the traditional building shell measures to include efficient appliances and solar access. These advanced measures are also included in the Utah program. The Long Term measures are curtailed by the 55 mill cost-effectiveness ceiling. The Company intends to include all the Long Term measures in field operation (subject to regulatory approval) but those savings would be in addition to the amounts shown here.

Appliance Program

This program is the least well-defined. A large technical potential has been identified for appliances, but little of that is achievable with the products currently on the market. This program relies primarily on supplying low-flow showerheads, compact fluorescent lightbulbs and water tank improvements to non-space heating customers. These customers would not otherwise be involved in a program since they are not being weatherized. The customer would pay a one-time fee and would receive substantial O&M savings as well as the energy savings. Since a large number of contacts must be made for small savings, the administrative overhead is high as a fraction of the measure cost. Customers are assumed to pay themselves for replacement of the measures after an estimated 10 year lifetime. The program is delayed under the Medium Low and Low growth scenarios. In these scenarios, there is some problem with end effects running past the planning horizon. As a result, the levelized cost fails to capture the full cost of the program in these two scenarios.

Water Heat Load Control Program

This program is directed entirely at demand savings. Participants will receive $2/month as a payment for their cooperation. The program seeks a slightly higher penetration in the high scenario. For the other scenarios, the difference is one of timing. Levelized cost works out to about $54/kW per year. This is slightly less expensive than other capacity options, such as combustion turbines. Notice that levelized cost computations are not correct when the program deployment is delayed due to end effects that occur beyond the planning horizon. The high or medium high case should be looked to for cost information.

INDHIGH

YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUMULATIVE ENERGY MWa	486	1.0	3.5	7.1	13.7	24.8	47.1	76.7	113.8	150.9	188.0	225.1
CUM CAPACITY MW	810	1.7	5.8	11.9	22.9	41.3	78.4	127.9	189.7	251.6	313.4	375.2
TOTAL YIELD MWh	4,255,242	8,845	30,638	62,583	120,325	217,216	412,206	672,192	997,176	1,322,159	1,647,142	1,972,126
CAPITAL INVEST K$	$1,290,988	$2,609	$4,121	$8,122	$10,003	$13,199	$15,782	$83,639	$104,549	$104,549	$104,549	$104,549
EXPENSE k$	$12,855	$221	$236	$103	$121	$127	$152	$804	$1,005	$1,005	$1,005	$1,005
CUSTOMER COST K$	$232,311	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESC REVENUE K$	$1,124,459	$274	$696	$1,574	$2,622	$3,977	$5,557	$14,683	$25,715	$36,212	$46,199	$55,702
INCRM ENERGY MWa	486	1.0	2.5	3.6	6.6	11.1	22.3	29.7	37.1	37.1	37.1	37.1
INCRM CAPACITY MW	810	1.7	4.1	6.1	11.0	18.4	37.1	49.5	61.8	61.8	61.8	61.8
INCRM. PENETRATION	64.2%	0.1%	0.4%	0.5%	0.9%	1.6%	3.1%	4.2%	5.2%	5.2%	5.2%	5.2%
NO. PARTICIPANTS	1,416	3	7	11	19	32	65	87	108	108	108	108
MEASURE COST k$	$1,240,932	$2,347	$3,721	$7,809	$9,618	$12,691	$15,175	$80,422	$100,528	$100,528	$100,528	$100,528
OVERHEAD k$	$50,056	$262	$400	$312	$385	$508	$607	$3,217	$4,021	$4,021	$4,021	$4,021

ESC INTEREST RATE=		8.00%	AVE. ANNUAL ESC REVENUE K$		$144,977
ESC TERM=		15	PROGRAM SAVINGS, % OF SALES=		9.3%
INFLATION RATE=		5.10%	MEASURE COST, $/1ST YR KWH=		0.292
TRC LC=	26.0		ADMIN OVERHEAD%=	4% ECMCOST	
UC LC=	-0.4		ADMIN EXPENSE%=	1% ECMCOST	
UTAH%=	52%		WEIGHTED LIFETIME=	17.4	

INDHIGH

YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUMULATIVE ENERGY MWa	262.2	299.3	336.4	369.6	396.8	411.7	426.5	441.3	456.2	471.0	485.8
CUM CAPACITY MW	437.0	498.9	560.7	616.0	661.4	686.1	710.8	735.6	760.3	784.9	809.6
TOTAL YIELD MWh	2,297,109	2,622,092	2,947,076	3,237,628	3,476,137	3,606,130	3,736,124	3,866,117	3,996,110	4,125,676	4,255,242
CAPITAL INVEST K$	$104,549	$104,549	$104,549	$93,625	$77,375	$41,819	$41,819	$41,819	$41,819	$41,697	$41,697
EXPENSE k$	$1,005	$1,005	$1,005	$900	$744	$402	$402	$402	$402	$401	$401
CUSTOMER COST K$	$0	$0	$0	$2,347	$3,721	$7,809	$9,618	$12,691	$15,175	$80,422	$100,528
ESC REVENUE K$	$64,744	$73,346	$81,532	$88,093	$92,380	$92,266	$91,740	$90,743	$89,151	$86,874	$80,380
INCRM ENERGY MWa	37.1	37.1	37.1	33.2	27.2	14.8	14.8	14.8	14.8	14.8	14.8
INCRM CAPACITY MW	61.8	61.8	61.8	55.3	45.4	24.7	24.7	24.7	24.7	24.7	24.7
INCRM. PENETRATION	5.2%	5.2%	5.2%	4.7%	3.8%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
NO. PARTICIPANTS	108	108	108	97	80	43	43	43	43	43	43
MEASURE COST k$	$100,528	$100,528	$100,528	$90,024	$74,399	$40,211	$40,211	$40,211	$40,211	$40,094	$40,094
OVERHEAD k$	$4,021	$4,021	$4,021	$3,601	$2,976	$1,608	$1,608	$1,608	$1,608	$1,604	$1,604

INDMEDHI

YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUMULATIVE ENERGY MWa	387	1.0	3.0	6.0	11.2	20.1	37.8	61.4	90.9	120.4	150.0	179.5
CUM CAPACITY MW	644	1.7	5.1	10.0	18.7	33.5	63.0	102.4	151.6	200.7	249.9	299.1
TOTAL YEILD MWh	3,386,668	8,845	26,605	52,486	98,544	176,260	331,357	538,151	796,645	1,055,139	1,313,632	1,572,126
CAPITAL INVEST K$	$1,029,632	$2,609	$4,121	$8,122	$10,003	$13,199	$15,782	$66,001	$82,501	$82,501	$82,501	$82,501
EXPENSE k$	$10,342	$221	$236	$103	$121	$127	$152	$635	$793	$793	$793	$793
CUSTOMER COST K$	$194,152	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESC REVENUE K$	$897,720	$274	$696	$1,574	$2,622	$3,977	$5,557	$12,702	$21,353	$29,585	$37,417	$44,869
INCRM ENERGY MWa	387	1.0	2.0	3.0	5.3	8.9	17.7	23.6	29.5	29.5	29.5	29.5
INCRM CAPACITY MW	644	1.7	3.4	4.9	8.8	14.8	29.5	39.3	49.2	49.2	49.2	49.2
INCRM. PENETRATION	64.7%	0.2%	0.4%	0.5%	0.9%	1.6%	3.2%	4.2%	5.3%	5.3%	5.3%	5.3%
NO. PARTICIPANTS	1,129	3	6	9	15	26	52	69	86	86	86	86
MEASURE COST k$	$989,628	$2,347	$3,721	$7,809	$9,618	$12,691	$15,175	$63,463	$79,328	$79,328	$79,328	$79,328
OVERHEAD k$	$40,004	$262	$400	$312	$385	$508	$607	$2,539	$3,173	$3,173	$3,173	$3,173

ESC INTEREST RATE=	8.00%	AVE. ANNUAL ESC REVENUE K$		$115,618
ESC TERM=	15	PROGRAM SAVINGS, % OF SALES=		9.4%
INFLATION RATE=	5.10%	MEASURE COST, $/1ST YR KWH=		0.292
TRC LC=	26.3	ADMIN OVERHEAD%=	4% ECMCOST	
UC LC=	-0.4	ADMIN EXPENSE%=	1% ECMCOST	
UTAH%=	52%	WEIGHTED LIFETIME=	17.4	

INDMEDHI

YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUMULATIVE ENERGY MWa	209.0	238.5	268.0	294.3	315.9	327.7	339.5	351.3	363.1	374.8	386.6
CUM CAPACITY MW	348.3	397.5	446.7	490.5	526.4	546.1	565.8	585.4	605.1	624.7	644.3
TOTAL YEILD MWh	1,830,619	2,089,113	2,347,606	2,578,058	2,766,852	2,870,249	2,973,647	3,077,044	3,180,441	3,283,555	3,386,668
CAPITAL INVEST K$	$82,501	$82,501	$82,501	$73,678	$60,767	$33,001	$33,001	$33,001	$33,001	$32,920	$32,920
EXPENSE k$	$793	$793	$793	$708	$584	$317	$317	$317	$317	$317	$317
CUSTOMER COST K$	$0	$0	$0	$2,347	$3,721	$7,809	$9,618	$12,691	$15,175	$63,463	$79,328
ESC REVENUE K$	$51,960	$58,706	$65,125	$70,242	$73,530	$73,339	$72,741	$71,675	$70,018	$67,684	$62,074
INCRM ENERGY MWa	29.5	29.5	29.5	26.3	21.6	11.8	11.8	11.8	11.8	11.8	11.8
INCRM CAPACITY MW	49.2	49.2	49.2	43.8	35.9	19.7	19.7	19.7	19.7	19.6	19.6
INCRM. PENETRATION	5.3%	5.3%	5.3%	4.7%	3.9%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
NO. PARTICIPANTS	86	86	86	77	63	34	34	34	34	34	34
MEASURE COST k$	$79,328	$79,328	$79,328	$70,844	$58,429	$31,731	$31,731	$31,731	$31,731	$31,654	$31,654
OVERHEAD k$	$3,173	$3,173	$3,173	$2,834	$2,337	$1,269	$1,269	$1,269	$1,269	$1,266	$1,266

INDMEDLO

YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUMULATIVE ENERGY MWa	266	1.0	2.4	4.5	8.0	14.1	26.3	42.5	62.8	83.0	103.3	123.6
CUM CAPACITY MW	443	1.7	4.0	7.5	13.4	23.5	43.8	70.8	104.6	138.4	172.2	206.0
TOTAL YEILD MWh	2,328,968	8,845	21,245	39,389	70,504	123,692	230,231	372,282	549,847	727,411	904,976	1,082,540
CAPITAL INVEST K$	$718,335	$2,609	$3,870	$8,122	$10,003	$13,199	$15,782	$44,965	$56,207	$56,207	$56,207	$56,207
EXPENSE k$	$7,351	$221	$236	$103	$121	$127	$152	$432	$540	$540	$540	$540
CUSTOMER COST K$	$148,642	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESC REVENUE K$	$627,811	$274	$696	$1,574	$2,622	$3,977	$5,557	$10,338	$16,151	$21,681	$26,943	$31,950
INCRM ENERGY MWa	266	1.0	1.4	2.1	3.6	6.1	12.2	16.2	20.3	20.3	20.3	20.3
INCRM CAPACITY MW	443	1.7	2.4	3.5	5.9	10.1	20.3	27.0	33.8	33.8	33.8	33.8
INCRM. PENETRATION	65.3%	0.3%	0.4%	0.5%	0.9%	1.6%	3.2%	4.3%	5.3%	5.3%	5.3%	5.3%
NO. PARTICIPANTS	776	3	4	6	10	18	36	47	59	59	59	59
MEASURE COST k$	$690,545	$2,347	$3,721	$7,809	$9,618	$12,691	$15,175	$43,236	$54,045	$54,045	$54,045	$54,045
OVERHEAD k$	$27,790	$262	$149	$312	$385	$508	$607	$1,729	$2,162	$2,162	$2,162	$2,162

ESC INTEREST RATE=	8.00%	AVE. ANNUAL ESC REVENUE K$		$80,676
ESC TERM=	15	PROGRAM SAVINGS, % OF SALES=		9.5%
INFLATION RATE=	5.10%	MEASURE COST, $/1ST YR KWH=		0.297
TRC LC=	27.1	ADMIN OVERHEAD%=	4% ECMCOST	
UC LC=	-0.4	ADMIN EXPENSE%=	1% ECMCOST	
UTAH%=	49%	WEIGHTED LIFETIME=	17.4	

INDMEDLO

YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUMULATIVE ENERGY MWa	143.8	164.1	184.4	202.5	217.3	225.4	233.5	241.6	249.7	257.8	265.9
CUM CAPACITY MW	239.7	273.5	307.3	337.4	362.1	375.6	389.1	402.7	416.2	429.6	443.1
TOTAL YEILD MWh	1,260,105	1,437,669	1,615,234	1,773,606	1,903,299	1,974,325	2,045,351	2,116,377	2,187,403	2,258,185	2,328,968
CAPITAL INVEST K$	$56,207	$56,207	$56,207	$50,197	$41,383	$22,483	$22,483	$22,483	$22,483	$22,414	$22,414
EXPENSE k$	$540	$540	$540	$483	$398	$216	$216	$216	$216	$216	$216
CUSTOMER COST K$	$0	$0	$0	$2,347	$3,721	$7,809	$9,618	$12,691	$15,175	$43,236	$54,045
ESC REVENUE K$	$36,713	$41,246	$45,558	$48,987	$51,128	$50,843	$50,155	$49,004	$47,266	$44,855	$40,294
INCRM ENERGY MWa	20.3	20.3	20.3	18.1	14.8	8.1	8.1	8.1	8.1	8.1	8.1
INCRM CAPACITY MW	33.8	33.8	33.8	30.1	24.7	13.5	13.5	13.5	13.5	13.5	13.5
INCRM. PENETRATION	5.3%	5.3%	5.3%	4.7%	3.9%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
NO. PARTICIPANTS	59	59	59	53	43	24	24	24	24	24	24
MEASURE COST k$	$54,045	$54,045	$54,045	$48,266	$39,791	$21,618	$21,618	$21,618	$21,618	$21,552	$21,552
OVERHEAD k$	$2,162	$2,162	$2,162	$1,931	$1,592	$865	$865	$865	$865	$862	$862

INDLOW												
YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUMULATIVE ENERGY MWa	188	1.0	2.1	3.7	5.4	7.2	9.9	12.5	15.0	17.6	22.5	31.7
CUM CAPACITY MW	314	1.7	3.5	6.2	9.1	12.1	16.4	20.8	25.1	29.4	37.5	52.9
TOTAL YEILD MWh	1,649,915	8,845	18,515	32,674	47,664	63,449	86,365	109,149	131,717	154,285	197,055	277,843
CAPITAL INVEST K$	$542,390	$2,609	$3,870	$8,122	$10,003	$13,199	$15,782	$7,120	$7,051	$7,051	$13,421	$25,380
EXPENSE k$	$5,659	$221	$236	$103	$121	$127	$152	$68	$68	$68	$129	$244
CUSTOMER COST K$	$64,987	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESC REVENUE K$	$363,747	$274	$696	$1,574	$2,622	$3,977	$5,557	$6,087	$6,584	$7,056	$8,222	$10,674
INCRM ENERGY MWa	188	1.0	1.1	1.6	1.7	1.8	2.6	2.6	2.6	2.6	4.9	9.2
INCRM CAPACITY MW	314	1.7	1.8	2.7	2.9	3.0	4.4	4.3	4.3	4.3	8.1	15.4
INCRM. PENETRATION	66.2%	0.4%	0.4%	0.6%	0.6%	0.7%	1.0%	1.0%	1.0%	1.0%	1.8%	3.5%
NO. PARTICIPANTS	550	3	3	5	5	5	8	8	8	8	14	27
MEASURE COST k$	$521,367	$2,347	$3,721	$7,809	$9,618	$12,691	$15,175	$6,846	$6,780	$6,780	$12,905	$24,404
OVERHEAD k$	$21,023	$262	$149	$312	$385	$508	$607	$274	$271	$271	$516	$976

ESC INTEREST RATE=		8.00%	AVE. ANNUAL ESC REVENUE K$	$60,911
ESC TERM=		15	PROGRAM SAVINGS, % OF SALES=	9.5%
INFLATION RATE=		5.10%	MEASURE COST, $/1ST YR KWH=	0.316
TRC LC=	28.2		ADMIN OVERHEAD%=	4% ECMCOST
UC LC=	-0.4		ADMIN EXPENSE%=	1% ECMCOST
UTAH%=	44%		WEIGHTED LIFETIME=	16.0

INDLOW											
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUMULATIVE ENERGY MWa	45.3	59.6	73.9	88.2	102.5	116.8	131.1	145.4	159.7	174.0	188.3
CUM CAPACITY MW	75.4	99.3	123.1	147.0	170.8	194.7	218.5	242.4	266.2	290.1	313.9
TOTAL YEILD MWh	396,522	521,861	647,201	772,540	897,879	1,023,219	1,148,558	1,273,897	1,399,237	1,524,576	1,649,915
CAPITAL INVEST K$	$37,176	$39,161	$39,161	$39,161	$39,161	$39,161	$39,161	$39,161	$39,161	$39,161	$39,161
EXPENSE k$	$357	$377	$377	$377	$377	$377	$377	$377	$377	$377	$377
CUSTOMER COST K$	$0	$0	$0	$2,347	$3,721	$7,809	$9,618	$12,691	$15,175	$6,846	$6,780
ESC REVENUE K$	$14,332	$18,036	$21,560	$24,913	$27,973	$30,685	$32,848	$34,411	$35,254	$35,307	$35,107
INCRM ENERGY MWa	13.5	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
INCRM CAPACITY MW	22.6	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
INCRM. PENETRATION	5.1%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%
NO. PARTICIPANTS	40	42	42	42	42	42	42	42	42	42	42
MEASURE COST k$	$35,746	$37,655	$37,655	$37,655	$37,655	$37,655	$37,655	$37,655	$37,655	$37,655	$37,655
OVERHEAD k$	$1,430	$1,506	$1,506	$1,506	$1,506	$1,506	$1,506	$1,506	$1,506	$1,506	$1,506

NEW COMML	FORECAST	HIGH											
YEAR		TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUM ENERGY, MWa		163.4	0.4	2.5	5.6	10.4	17.7	26.5	35.2	43.7	52.7	61.8	70.9
CUM CAPACITY, MW		233.4	0.6	3.6	8.0	14.9	25.3	37.9	50.3	62.5	75.3	88.3	101.2
CUM. NET EN., MWH		1,431,345	3,820	22,125	49,133	91,525	155,378	232,465	308,194	382,975	461,520	541,309	620,790
CUM PENETRATION		74%	6%	15%	21%	28%	38%	46%	52%	56%	59%	62%	64%
CUM. GROSS EN., MWa			0.8	4.3	9.4	17.4	29.6	44.3	58.7	73.1	88.3	103.8	119.4
INCRM UTIL COST, k$		$751,539	$2,617	$8,069	$13,900	$22,262	$33,379	$40,016	$39,438	$39,151	$40,864	$41,423	$41,386
INCRM UTIL EXPENSE, k$		$11,459	$89	$178	$228	$329	$492	$625	$615	$600	$629	$638	$633
INCRM CUSTOMER COST, k$		$146,879	$109	$479	$742	$944	$1,358	$1,534	$1,418	$1,308	$1,416	$1,412	$1,319
ESC REVENUE, k$		$475,153	$220	$1,164	$2,443	$4,462	$7,468	$11,000	$14,305	$17,414	$20,541	$23,575	$26,458
INCRM PENETRATION		74%	0%	23%	31%	49%	72%	85%	85%	85%	85%	85%	85%
INCR GROSS EN, MWH		2,466,750	6,597	31,276	44,134	70,402	106,501	129,028	126,701	125,750	133,107	136,186	136,154
MEASURE COST, k$		$590,374	$1,776	$7,690	$10,765	$17,232	$25,975	$31,396	$30,941	$30,653	$32,022	$32,487	$32,459
DEF OVERHEAD, k$		$161,165	$841	$379	$3,135	$5,029	$7,405	$8,620	$8,497	$8,499	$8,842	$8,936	$8,926
EXPENSE, k$		$11,459	$89	$178	$228	$329	$492	$625	$615	$600	$629	$638	$633

TRC	28.5	AVE. ANNUAL ESC REVENUE, k$	$73,241			
UC	5.1	ADMINISTRATIVE ADDER, DEFERRED		29%	FRACTION OF NET SALES	13%
UTAH %	45%	ADMINISTRATIVE ADDER, EXPENSE		1%		
WEIGHTED LIFE	15.8	ESC LOAN RATE		9%		

NEW COMML											
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUM ENERGY, MWa	79.8	88.5	97.1	105.6	114.2	122.6	130.9	139.2	147.4	155.5	163.4
CUM CAPACITY, MW	113.9	126.5	138.7	150.9	163.1	175.1	187.0	198.8	210.6	222.2	233.4
CUM. NET EN., MWH	698,696	775,622	850,479	925,314	1,000,159	1,073,802	1,146,675	1,219,008	1,291,347	1,362,573	1,431,345
CUM PENETRATION	66%	67%	68%	70%	70%	71%	72%	73%	73%	74%	74%
CUM. GROSS EN., MWa	134.7	149.8	164.5	179.3	194.2	208.9	223.5	238.1	252.6	267.3	281.6
INCRM UTIL COST, k$	$40,791	$40,321	$39,507	$39,554	$39,670	$39,126	$38,774	$38,503	$38,527	$38,072	$36,189
INCRM UTIL EXPENSE, k$	$621	$614	$597	$592	$589	$580	$572	$572	$570	$562	$534
INCRM CUSTOMER COST, k$	$1,184	$1,122	$991	$945	$2,653	$8,499	$11,537	$17,979	$26,690	$31,952	$31,289
ESC REVENUE, k$	$29,141	$31,651	$33,956	$36,154	$38,151	$35,982	$33,752	$31,257	$28,398	$25,312	$22,348
INCRM PENETRATION	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
INCR GROSS EN, MWH	133,799	132,371	129,118	129,932	130,483	128,855	127,886	127,218	127,709	128,260	125,284
MEASURE COST, k$	$31,977	$31,631	$30,956	$31,005	$31,083	$30,659	$30,369	$30,161	$30,198	$29,854	$29,084
DEF OVERHEAD, k$	$8,814	$8,690	$8,551	$8,549	$8,588	$8,467	$8,405	$8,343	$8,329	$8,218	$7,104
EXPENSE, k$	$621	$614	$597	$592	$589	$580	$572	$572	$570	$562	$534

NEW COMML	FORECAST	MEDIUM HIGH										
YEAR		TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUM ENERGY, MWa		147.2	0.4	2.4	5.2	9.6	16.3	24.3	32.2	40.0	48.1	56.4	64.6
CUM CAPACITY, MW		215.5	2.5	6.0	11.6	18.7	27.9	40.4	56.2	75.1	93.5	111.5	128.9
CUM. NET EN., MWH		1,289,303	3,809	20,722	45,492	84,277	142,675	213,172	282,161	350,008	421,380	493,755	565,653
CUM PENETRATION		74%	7%	16%	21%	29%	38%	46%	52%	56%	59%	62%	64%
CUM. GROSS EN., MWa			0.8	4.1	8.7	16.1	27.3	40.8	54.1	67.1	81.0	95.2	109.3
INCRM UTIL COST, k$		$679,280	$2,617	$7,484	$12,748	$20,387	$30,534	$36,611	$35,958	$35,601	$37,189	$37,645	$37,531
INCRM UTIL EXPENSE, k$		$9,981	$89	$178	$210	$299	$445	$562	$550	$531	$557	$561	$558
INCRM CUSTOMER COST, k$		$131,761	$107	$436	$669	$832	$1,181	$1,306	$1,193	$1,073	$1,176	$1,163	$1,070
ESC REVENUE, k$		$431,542	$220	$1,091	$2,262	$4,109	$6,857	$10,087	$13,097	$15,918	$18,760	$21,511	$24,118
INCRM PENETRATION		74%	0%	24%	31%	49%	72%	85%	85%	85%	85%	85%	85%
INCR GROSS EN, MWH		2,232,483	6,597	29,090	40,699	64,754	97,890	118,560	115,955	114,668	121,577	124,168	123,858
MEASURE COST, k$		$533,286	$1,772	$7,105	$9,871	$15,773	$23,753	$28,723	$28,206	$27,861	$29,134	$29,514	$29,425
DEF OVERHEAD, k$		$145,994	$845	$379	$2,877	$4,614	$6,781	$7,888	$7,752	$7,739	$8,055	$8,131	$8,105
EXPENSE, k$		$9,981	$89	$178	$210	$299	$445	$562	$550	$531	$557	$561	$558

TRC	28.4	AVE. ANNUAL ESC REVENUE, k$	$66,159			
UC	5.1	ADMINISTRATIVE ADDER, DEFERRED	29%	FRACTION OF NET SALES	13%
UTAH %	46%	ADMINISTRATIVE ADDER, EXPENSE	1%		
WEIGHTED LIFE	15.8	ESC LOAN RATE	9%		

NEW COMML											
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUM ENERGY, MWa	72.6	80.5	88.1	95.7	103.4	110.8	118.2	125.5	132.8	140.1	147.2
CUM CAPACITY, MW	103.7	115.0	125.9	136.8	147.7	158.3	168.9	179.3	189.7	200.1	210.3
CUM. NET EN., MWH	635,906	704,971	771,923	838,752	905,401	970,769	1,035,391	1,099,239	1,163,021	1,227,168	1,289,303
CUM PENETRATION	66%	67%	68%	69%	70%	71%	72%	72%	73%	74%	74%
CUM. GROSS EN., MWa	123.2	136.8	150.1	163.4	176.8	189.9	202.9	215.8	228.8	242.0	254.8
INCRM UTIL COST, k$	$36,878	$36,341	$35,487	$35,470	$35,495	$34,914	$34,557	$34,181	$34,179	$34,520	$32,954
INCRM UTIL EXPENSE, k$	$541	$533	$513	$508	$502	$488	$483	$476	$474	$473	$450
INCRM CUSTOMER COST, k$	$935	$864	$739	$689	$2,389	$7,654	$10,381	$16,251	$24,202	$29,068	$28,380
ESC REVENUE, k$	$26,533	$28,780	$30,831	$32,783	$34,536	$32,552	$30,521	$28,239	$25,631	$22,896	$20,213
INCRM PENETRATION	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
INCR GROSS EN, MWH	121,316	119,543	116,177	116,776	116,922	115,163	114,094	113,001	113,344	115,458	112,873
MEASURE COST, k$	$28,900	$28,492	$27,792	$27,789	$27,796	$27,336	$27,047	$26,757	$26,751	$27,048	$26,439
DEF OVERHEAD, k$	$7,978	$7,848	$7,695	$7,680	$7,699	$7,578	$7,510	$7,424	$7,428	$7,472	$6,515
EXPENSE, k$	$541	$533	$513	$508	$502	$488	$483	$476	$474	$473	$450

NEW COMML FORECAST	MEDIUM LOW											
YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUM ENERGY, MWa	100.1	0.4	1.3	3.8	7.9	13.0	18.6	23.9	29.2	34.7	40.2	45.5
CUM CAPACITY, MW	143.1	0.6	1.9	5.4	11.2	18.6	26.5	34.1	41.8	49.5	57.4	65.1
CUM. NET EN., MWH	877,267	3,936	11,390	32,968	68,831	113,931	162,507	209,242	256,106	303,770	351,829	398,933
CUM PENETRATION	74%	11%	19%	27%	35%	42%	49%	53%	57%	60%	62%	64%
CUM. GROSS EN., MWa		0.7	2.1	6.2	13.1	21.6	30.7	39.5	48.3	57.4	66.6	75.7
INCRM UTIL COST, k$	$465,848	$1,191	$4,378	$11,427	$18,758	$23,580	$25,638	$24,822	$24,865	$25,183	$25,286	$24,874
INCRM UTIL EXPENSE, k$	$7,422	$145	$356	$191	$281	$358	$405	$386	$382	$384	$387	$375
INCRM CUSTOMER COST, k$	$96,893	$38	$146	$556	$891	$946	$845	$740	$724	$742	$755	$683
ESC REVENUE, k$	$299,793	$96	$487	$1,538	$3,247	$5,373	$7,607	$9,652	$11,600	$13,485	$15,291	$16,969
INCRM PENETRATION	74%	0%	26%	39%	53%	72%	85%	85%	85%	85%	85%	85%
INCR GROSS EN, MWH	1,499,200	6,485	11,834	35,999	60,298	74,813	79,809	76,666	77,433	79,477	80,704	79,405
MEASURE COST, k$	$364,536	$776	$3,189	$8,662	$14,373	$18,405	$20,117	$19,453	$19,477	$19,732	$19,833	$19,513
DEF OVERHEAD, k$	$101,313	$415	$1,189	$2,765	$4,385	$5,175	$5,521	$5,368	$5,388	$5,451	$5,454	$5,361
EXPENSE, k$	$7,422	$145	$356	$191	$281	$358	$405	$386	$382	$384	$387	$375

TRC	29.5	AVE. ANNUAL ESC REVENUE, k$	$45,224	
UC	5.3	ADMINISTRATIVE ADDER, DEFERRED	29%	FRACTION OF NET SALES 14%
UTAH %	43%	ADMINISTRATIVE ADDER, EXPENSE	1%	
WEIGHTED LIFE	15.8	ESC LOAN RATE	9%	

NEW COMML											
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUM ENERGY, MWa	50.7	55.7	60.7	65.9	71.1	76.3	81.4	86.4	91.2	95.7	100.1
CUM CAPACITY, MW	72.5	79.6	86.8	94.2	101.6	109.1	116.3	123.4	130.3	136.7	143.1
CUM. NET EN., MWH	444,563	488,266	532,086	577,611	623,221	668,775	713,338	756,647	798,802	838,528	877,267
CUM PENETRATION	66%	67%	68%	69%	70%	71%	71%	72%	73%	73%	74%
CUM. GROSS EN., MWa	84.5	93.0	101.6	110.6	119.8	129.0	137.9	146.6	155.1	163.2	171.1
INCRM UTIL COST, k$	$24,261	$23,470	$23,539	$24,250	$24,470	$24,236	$23,703	$23,056	$22,505	$21,686	$20,671
INCRM UTIL EXPENSE, k$	$360	$343	$343	$356	$357	$356	$351	$344	$337	$317	$307
INCRM CUSTOMER COST, k$	$577	$476	$474	$535	$1,217	$3,713	$9,180	$14,862	$18,838	$20,352	$19,605
ESC REVENUE, k$	$18,507	$19,889	$21,208	$22,536	$23,774	$22,527	$20,987	$19,173	$17,219	$15,222	$13,407
INCRM PENETRATION	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
INCR GROSS EN, MWH	77,289	74,424	75,176	78,946	80,678	80,193	78,470	76,300	74,655	70,784	69,361
MEASURE COST, k$	$19,034	$18,376	$18,412	$19,002	$19,159	$18,994	$18,571	$18,077	$17,674	$16,991	$16,715
DEF OVERHEAD, k$	$5,227	$5,094	$5,127	$5,247	$5,311	$5,242	$5,132	$4,979	$4,831	$4,695	$3,956
EXPENSE, k$	$360	$343	$343	$356	$357	$356	$351	$344	$337	$317	$307

NEW COMML	FORECAST LOW											
YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUM ENERGY, MWa	61.6	0.4	1.3	3.1	6.3	9.9	13.7	17.2	20.7	24.2	27.7	31.0
CUM CAPACITY, MW	88.0	0.6	1.8	4.4	8.9	14.2	19.6	24.6	29.5	34.6	39.6	44.4
CUM. NET EN., MWH	539,397	3,903	11,126	27,159	54,755	87,148	120,050	150,728	181,125	211,904	242,550	271,987
CUM PENETRATION	71%	14%	18%	23%	31%	39%	46%	51%	54%	57%	60%	62%
CUM. GROSS EN., MWa		0.8	2.1	5.3	10.6	16.8	23.0	28.8	34.5	40.4	46.4	52.1
INCRM UTIL COST, k$	$298,803	$2,617	$3,704	$8,575	$14,273	$17,098	$17,698	$16,710	$16,589	$16,733	$16,622	$16,097
INCRM UTIL EXPENSE, k$	$4,314	$89	$178	$112	$215	$257	$275	$251	$246	$243	$240	$228
INCRM CUSTOMER COST, k$	$70,774	$34	$126	$469	$755	$744	$624	$511	$494	$509	$513	$442
ESC REVENUE, k$	$203,310	$243	$644	$1,425	$2,735	$4,261	$5,777	$7,122	$8,388	$9,607	$10,758	$11,802
INCRM PENETRATION	71%	0%	22%	30%	51%	73%	85%	85%	85%	85%	85%	85%
INCR GROSS EN, MWH	931,408	6,597	12,230	27,345	46,858	54,122	54,338	50,548	50,492	51,693	51,913	50,128
MEASURE COST, k$	$234,326	$1,963	$3,325	$6,545	$11,118	$13,370	$13,887	$13,100	$12,990	$13,105	$13,036	$12,628
DEF OVERHEAD, k$	$64,478	$654	$379	$2,031	$3,155	$3,728	$3,811	$3,610	$3,599	$3,628	$3,586	$3,469
EXPENSE, k$	$4,314	$89	$178	$112	$215	$257	$275	$251	$246	$243	$240	$228

TRC	31.1	AVE. ANNUAL ESC REVENUE, k$	$29,070	
UC	5.4	ADMINISTRATIVE ADDER, DEFERRED	29%	FRACTION OF NET SALES 14%
UTAH %	42%	ADMINISTRATIVE ADDER, EXPENSE	1%	
WEIGHTED LIFE	15.8	ESC LOAN RATE	9%	

NEW COMML											
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUM ENERGY, MWa	34.2	37.1	40.0	43.1	46.0	49.0	51.7	54.4	56.9	59.2	61.6
CUM CAPACITY, MW	48.9	53.1	57.2	61.5	65.8	69.9	73.9	77.7	81.2	84.6	88.0
CUM. NET EN., MWH	299,715	325,351	350,772	377,215	403,260	428,863	453,257	476,332	498,041	518,987	539,397
CUM PENETRATION	63%	64%	66%	67%	68%	68%	69%	70%	70%	71%	71%
CUM. GROSS EN., MWa	57.5	62.6	67.6	72.9	78.3	83.6	88.6	93.4	97.9	102.2	106.3
INCRM UTIL COST, k$	$15,376	$14,513	$14,415	$14,826	$14,788	$14,411	$13,767	$13,097	$12,480	$12,439	$11,973
INCRM UTIL EXPENSE, k$	$213	$193	$190	$197	$192	$189	$180	$171	$161	$150	$144
INCRM CUSTOMER COST, k$	$342	$246	$243	$287	$2,157	$3,593	$6,804	$11,348	$13,543	$13,923	$13,069
ESC REVENUE, k$	$12,726	$13,517	$14,258	$15,006	$15,599	$14,680	$13,587	$12,275	$10,894	$9,602	$8,404
INCRM PENETRATION	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
INCR GROSS EN, MWH	47,500	44,238	44,290	46,698	47,263	46,128	43,961	41,579	39,447	37,593	36,447
MEASURE COST, k$	$12,065	$11,352	$11,259	$11,609	$11,574	$11,282	$10,775	$10,264	$9,775	$9,728	$9,574
DEF OVERHEAD, k$	$3,311	$3,160	$3,156	$3,217	$3,214	$3,129	$2,992	$2,833	$2,705	$2,711	$2,400
EXPENSE, k$	$213	$193	$190	$197	$192	$189	$180	$171	$161	$150	$144

FORECAST COMHIGH ALL COSTS IN REAL $, INCLUDES LINE LOSSES

COML RETROFIT												
YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUM ENERGY, MWa	129.5	1.5	5.1	9.4	15.0	21.7	30.5	42.1	53.3	64.2	74.9	85.3
CUM CAPACITY, MW	215.9	2.5	8.4	15.7	25.1	36.2	50.9	70.1	88.8	107.1	124.9	142.2
CUM NET ENERGY, MWH	1,134,698	13,242	44,268	82,308	131,809	190,492	267,596	368,419	466,806	562,757	656,271	747,350
CUM PENETRATION	66%	1%	2%	4%	6%	9%	13%	18%	23%	28%	33%	38%
CUM EN., GROSS MWa	172	1.5	5.2	9.8	15.9	23.3	33.0	46.0	59.0	72.0	85.0	97.9
INCRM UTIL COST	$531,492	$2,325	$11,446	$14,067	$18,465	$21,957	$30,512	$40,432	$40,432	$40,432	$40,432	$40,432
INCRM UTIL EXPENSE	$4,074	$30	$89	$112	$147	$177	$235	$308	$308	$308	$308	$308
INCRM CUSTOMER COST	$91,604	$282	$183	$229	$365	$465	$652	$1,058	$1,058	$1,058	$1,058	$1,058
ESC REVENUE, k$	$497,331	$447	$1,744	$3,307	$5,311	$7,659	$10,753	$14,774	$18,601	$22,242	$25,706	$29,003
INCRM PENETRATION	66%	1%	1%	2%	2%	3%	4%	5%	5%	5%	5%	5%
INCRM GROSS EN, MWH	1,506,333	13,551	32,222	40,278	53,304	64,341	85,754	113,690	113,690	113,690	113,690	113,690
MEASURE COST, k$	$483,325	$2,067	$10,625	$13,281	$17,447	$21,008	$27,931	$36,625	$36,625	$36,625	$36,625	$36,625
DEF OVERHEAD, k$	$48,167	$258	$821	$786	$1,018	$948	$2,581	$3,807	$3,807	$3,807	$3,807	$3,807
EXPENSE, k$	$4,074	$30	$89	$112	$147	$177	$235	$308	$308	$308	$308	$308

		ESC LOAN RATE	9%	
TRC	31.6	AVE. ANNUAL ESC REVENUE, k$	$59,961	
UC	-0.9	DESIGN/AUDIT COST ADDER	19%	FRACTION OF NET SALES 25%
UTAH %	40%	ADMINISTRATIVE ADDER, DEFERRED	20%	
WEIGHTED LIFE	16.1	ADMINISTRATIVE ADDER, EXPENSE	1%	

COML RETROFIT											
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUM ENERGY, MWa	95.4	105.3	114.8	120.3	124.1	127.1	128.6	128.9	129.2	129.4	129.5
CUM CAPACITY, MW	159.1	175.5	191.4	200.5	206.9	211.8	214.4	214.9	215.3	215.7	215.9
CUM NET ENERGY, MWH	835,992	922,197	1,005,967	1,054,080	1,087,451	1,112,992	1,126,894	1,129,576	1,131,770	1,133,478	1,134,696
CUM PENETRATION	43%	48%	53%	56%	59%	61%	62%	63%	64%	65%	66%
CUM EN., GROSS MWa	110.9	123.9	136.9	145.3	151.8	157.5	161.6	164.2	166.8	169.4	172.0
INCRM UTIL COST	$40,432	$40,432	$40,432	$26,191	$20,456	$17,489	$12,788	$8,086	$8,086	$8,086	$8,086
INCRM UTIL EXPENSE	$308	$308	$308	$199	$154	$129	$95	$62	$62	$62	$62
INCRM CUSTOMER COST	$1,058	$1,058	$1,058	$729	$638	$2,428	$9,379	$11,372	$14,873	$17,866	$23,683
ESC REVENUE, k$	$32,139	$35,123	$37,962	$39,051	$39,217	$36,434	$33,478	$30,396	$27,729	$24,785	$21,472
INCRM PENETRATION	5%	5%	5%	3%	2%	2%	2%	1%	1%	1%	1%
INCRM GROSS EN, MWH	113,690	113,690	113,690	73,642	57,531	49,245	35,992	22,738	22,738	22,738	22,738
MEASURE COST, k$	$36,625	$36,625	$36,625	$23,629	$18,317	$15,375	$11,350	$7,325	$7,325	$7,325	$7,325
DEF OVERHEAD, k$	$3,807	$3,807	$3,807	$2,562	$2,139	$2,114	$1,438	$761	$761	$761	$761
EXPENSE, k$	$308	$308	$308	$199	$154	$129	$95	$62	$62	$62	$62

FORECAST COMMEDHI ALL COSTS IN REAL $, INCLUDES LINE LOSSES

COML RETROFIT

YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUM ENERGY, MWa	129.3	1.5	3.6	6.9	11.2	16.8	24.2	33.7	45.0	56.1	66.9	77.4
CUM CAPACITY, MW	215.5	2.5	6.0	11.6	18.7	27.9	40.4	56.2	75.1	93.5	111.5	128.9
CUM NET ENERGY, MWH	1,132,848	13,242	31,795	60,724	98,139	146,876	212,124	295,392	394,632	491,436	585,804	677,736
CUM PENETRATION	66%	1%	2%	3%	5%	7%	10%	15%	20%	25%	30%	35%
CUM EN., GROSS MWa	172	1.5	3.8	7.2	11.8	17.9	26.2	36.9	49.9	62.9	75.8	88.8
INCRM UTIL COST	$532,004	$2,325	$7,196	$10,879	$14,299	$18,395	$25,763	$33,379	$40,432	$40,432	$40,432	$40,432
INCRM UTIL EXPENSE	$4,066	$30	$54	$85	$112	$147	$199	$257	$308	$308	$308	$308
INCRM CUSTOMER COST	$75,311	$282	$110	$174	$229	$365	$511	$698	$1,058	$1,058	$1,058	$1,058
ESC REVENUE, k$	$475,433	$447	$1,216	$2,410	$3,940	$5,913	$8,562	$11,941	$15,906	$19,677	$23,266	$26,681
INCRM PENETRATION	66%	1%	1%	1%	2%	2%	3%	4%	5%	5%	5%	5%
INCRM GROSS EN, MWH	1,503,802	13,551	19,333	30,611	40,278	53,304	72,397	93,810	113,690	113,690	113,690	113,690
MEASURE COST, k$	$482,386	$2,067	$6,375	$10,094	$13,281	$17,447	$23,665	$30,587	$36,625	$36,625	$36,625	$36,625
DEF OVERHEAD, k$	$49,619	$258	$821	$786	$1,018	$948	$2,099	$2,792	$3,807	$3,807	$3,807	$3,807
EXPENSE, k$	$4,066	$30	$54	$85	$112	$147	$199	$257	$308	$308	$308	$308

		ESC LOAN RATE	9%			
TRC	31.0	AVE. ANNUAL ESC REVENUE, k$		$59,844		
UC	-0.8	DESIGN/AUDIT COST ADDER	19%	FRACTION OF NET SALES	25%	
UTAH %	40%	ADMINISTRATIVE ADDER, DEFERRED	20%			
WEIGHTED LIFE	15.9	ADMINISTRATIVE ADDER, EXPENSE	1%			

COML RETROFIT

YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUM ENERGY, MWa	87.6	97.5	107.2	116.6	120.8	123.8	126.6	128.1	129.0	129.2	129.3
CUM CAPACITY, MW	146.0	162.5	178.6	194.3	201.3	206.3	211.0	213.5	215.0	215.3	215.5
CUM NET ENERGY, MWH	767,232	854,291	938,914	1,021,101	1,058,242	1,084,163	1,109,037	1,122,411	1,129,861	1,131,599	1,132,848
CUM PENETRATION	40%	45%	50%	55%	57%	59%	61%	63%	64%	65%	66%
CUM EN., GROSS MWa	101.8	114.8	127.8	140.7	147.8	153.4	159.0	163.1	166.5	169.1	171.7
INCRM UTIL COST	$40,432	$40,432	$40,432	$40,432	$21,939	$17,489	$17,489	$12,788	$10,437	$8,086	$8,086
INCRM UTIL EXPENSE	$308	$308	$308	$308	$166	$129	$129	$95	$78	$62	$62
INCRM CUSTOMER COST	$1,058	$1,058	$1,058	$1,058	$611	$2,428	$6,048	$8,933	$11,492	$14,873	$20,098
ESC REVENUE, k$	$29,930	$33,021	$35,962	$38,761	$39,123	$36,421	$34,152	$31,307	$28,580	$25,608	$22,610
INCRM PENETRATION	5%	5%	5%	5%	3%	2%	2%	2%	1%	1%	1%
INCRM GROSS EN, MWH	113,690	113,690	113,690	113,690	61,674	49,245	49,245	35,992	29,365	22,738	22,738
MEASURE COST, k$	$36,625	$36,625	$36,625	$36,625	$19,787	$15,375	$15,375	$11,350	$9,337	$7,325	$7,325
DEF OVERHEAD, k$	$3,807	$3,807	$3,807	$3,807	$2,151	$2,114	$2,114	$1,438	$1,100	$761	$761
EXPENSE, k$	$308	$308	$308	$308	$166	$129	$129	$95	$78	$62	$62

FORECAST COMMED-LOW ALL COSTS IN REAL $, INCLUDES LINE LOSSES

COML RETROFIT												
YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUM ENERGY, MWa	128.8	1.5	2.4	5.8	9.2	13.9	19.7	26.7	36.5	47.6	58.5	69.1
CUM CAPACITY, MW	214.6	2.5	4.1	9.6	15.3	23.2	32.8	44.5	60.8	79.4	97.5	115.2
CUM NET ENERGY, MWH	1,127,866	13,242	21,453	50,490	80,393	121,790	172,424	234,063	319,471	417,165	512,422	605,244
CUM PENETRATION	66%	1%	1%	3%	4%	6%	9%	12%	16%	21%	26%	31%
CUM EN., GROSS MWa	171	1.5	2.5	6.0	9.7	14.9	21.3	29.2	40.4	53.4	66.3	79.3
INCRM UTIL COST	$530,818	$2,344	$3,888	$10,879	$11,643	$15,739	$20,028	$24,776	$34,696	$40,432	$40,432	$40,432
INCRM UTIL EXPENSE	$4,141	$115	$26	$85	$89	$124	$154	$190	$263	$308	$308	$308
INCRM CUSTOMER COST	$63,429	$282	$160	$174	$183	$319	$419	$561	$966	$1,058	$1,058	$1,058
ESC REVENUE, k$	$442,069	$447	$806	$2,019	$3,239	$4,917	$6,955	$9,424	$12,851	$16,771	$20,501	$24,049
INCRM PENETRATION	66%	1%	1%	1%	1%	2%	3%	3%	4%	5%	5%	5%
INCRM GROSS EN, MWH	1,497,738	13,551	8,666	30,611	32,222	45,248	56,286	69,643	97,579	113,690	113,690	113,690
MEASURE COST, k$	$481,119	$2,067	$3,066	$10,094	$10,625	$14,790	$18,352	$22,618	$31,312	$36,625	$36,625	$36,625
DEF OVERHEAD, k$	$49,699	$277	$821	$786	$1,018	$948	$1,675	$2,158	$3,384	$3,807	$3,807	$3,807
EXPENSE, k$	$4,141	$115	$26	$85	$89	$124	$154	$190	$263	$308	$308	$308

		ESC LOAN RATE	9%			
TRC	30.7	AVE. ANNUAL ESC REVENUE, k$		$59,687		
UC	-0.8	DESIGN/AUDIT COST ADDER	19%		FRACTION OF NET SALES	25%
UTAH %	40%	ADMINISTRATIVE ADDER, DEFERRED	20%			
WEIGHTED LIFE	15.7	ADMINISTRATIVE ADDER, EXPENSE	1%			

COML RETROFIT											
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUM ENERGY, MWa	79.4	89.4	99.2	108.7	116.4	122.8	126.0	127.5	128.4	128.6	128.8
CUM CAPACITY, MW	132.3	149.1	165.4	181.2	194.0	204.7	210.0	212.6	214.0	214.3	214.6
CUM NET ENERGY, MWH	695,629	783,578	869,091	952,168	1,019,862	1,075,649	1,103,866	1,117,287	1,124,785	1,126,569	1,127,866
CUM PENETRATION	36%	41%	46%	51%	55%	59%	61%	63%	64%	65%	66%
CUM EN., GROSS MWa	92.3	105.3	118.3	131.2	142.4	152.2	158.3	162.4	165.8	168.4	171.0
INCRM UTIL COST	$40,432	$40,432	$40,432	$40,432	$34,893	$30,542	$18,972	$12,788	$10,437	$8,086	$8,086
INCRM UTIL EXPENSE	$308	$308	$308	$308	$268	$233	$142	$95	$78	$62	$62
INCRM CUSTOMER COST	$1,058	$1,058	$1,058	$1,058	$768	$2,486	$3,241	$8,933	$9,260	$12,640	$15,634
ESC REVENUE, k$	$27,426	$30,639	$33,696	$36,604	$38,571	$36,199	$32,662	$29,872	$27,371	$24,770	$22,281
INCRM PENETRATION	5%	5%	5%	5%	4%	4%	2%	2%	1%	1%	1%
INCRM GROSS EN, MWH	113,690	113,690	113,690	113,690	98,040	85,841	53,388	35,992	29,365	22,738	22,738
MEASURE COST, k$	$36,625	$36,625	$36,625	$36,625	$31,883	$27,756	$16,846	$11,350	$9,337	$7,325	$7,325
DEF OVERHEAD, k$	$3,807	$3,807	$3,807	$3,807	$3,010	$2,786	$2,127	$1,438	$1,100	$761	$761
EXPENSE, k$	$308	$308	$308	$308	$268	$233	$142	$95	$78	$62	$62

FORECAST COMLOW ALL COSTS IN REAL $, INCLUDES LINE LOSSES

COML RETROFIT

YEAR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CUM ENERGY, MWa	129.9	1.5	2.4	3.4	4.4	5.3	7.1	9.4	12.3	15.8	20.3	26.4
CUM CAPACITY, MW	216.5	2.5	3.9	5.6	7.3	8.9	11.9	15.7	20.4	26.4	33.8	43.9
CUM NET ENERGY, MWH	1,138,075	13,242	20,709	29,603	38,297	46,791	62,601	82,705	107,469	138,613	177,791	230,853
CUM PENETRATION	67%	1%	1%	2%	2%	2%	3%	4%	5%	7%	9%	12%
CUM EN., GROSS MWa	172	1.5	2.4	3.5	4.6	5.7	7.7	10.3	13.6	17.8	23.1	30.3
INCRM UTIL COST	$536,908	$2,325	$3,237	$3,802	$4,034	$3,964	$6,260	$8,083	$10,107	$12,900	$16,459	$22,561
INCRM UTIL EXPENSE	$4,087	$30	$20	$25	$25	$25	$48	$62	$77	$98	$125	$172
INCRM CUSTOMER COST	$30,198	$282	$129	$114	$114	$114	$107	$170	$233	$337	$438	$547
ESC REVENUE, k$	$270,631	$447	$725	$1,064	$1,387	$1,694	$2,326	$3,132	$4,123	$5,373	$6,960	$9,168
INCRM PENETRATION	67%	1%	0%	0%	0%	0%	1%	1%	1%	2%	2%	3%
INCRM GROSS EN, MWH	1,510,778	13,551	7,865	9,528	9,528	9,528	17,650	22,886	28,666	36,484	46,467	63,516
MEASURE COST, k$	$484,820	$2,067	$2,416	$3,016	$3,016	$3,016	$5,761	$7,403	$9,216	$11,688	$14,895	$20,521
DEF OVERHEAD, k$	$52,088	$258	$821	$786	$1,018	$948	$499	$681	$891	$1,213	$1,564	$2,040
EXPENSE, k$	$4,087	$30	$20	$25	$25	$25	$48	$62	$77	$98	$125	$172

		ESC LOAN RATE	9%
TRC	29.4	AVE. ANNUAL ESC REVENUE, k$	$60,146
UC	-0.7	DESIGN/AUDIT COST ADDER	19%
UTAH %	40%	ADMINISTRATIVE ADDER, DEFERRED	20%
WEIGHTED LIFE	15.2	ADMINISTRATIVE ADDER, EXPENSE	1%

FRACTION OF NET SALES 25%

COML RETROFIT

YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUM ENERGY, MWa	34.8	44.2	54.6	65.4	75.8	86.3	96.5	106.3	115.9	124.5	129.9
CUM CAPACITY, MW	57.9	73.6	91.0	108.9	126.4	143.8	160.8	177.2	193.2	207.4	216.5
CUM NET ENERGY, MWH	304,412	386,965	478,158	572,478	664,210	756,023	845,151	931,594	1,015,352	1,090,208	1,138,075
CUM PENETRATION	16%	20%	25%	31%	36%	41%	47%	52%	58%	63%	67%
CUM EN., GROSS MWa	40.5	52.0	65.1	78.9	92.7	107.0	121.2	135.4	149.7	163.0	172.5
INCRM UTIL COST	$31,583	$36,140	$40,738	$43,164	$43,164	$44,364	$44,364	$44,364	$44,364	$41,398	$29,532
INCRM UTIL EXPENSE	$241	$275	$311	$331	$331	$339	$339	$339	$339	$315	$216
INCRM CUSTOMER COST	$811	$941	$1,032	$992	$992	$2,789	$3,082	$3,587	$3,587	$3,640	$6,158
ESC REVENUE, k$	$12,277	$15,744	$19,566	$23,501	$27,032	$25,942	$24,749	$23,614	$22,534	$20,980	$18,292
INCRM PENETRATION	4%	4%	5%	5%	5%	5%	5%	5%	5%	5%	4%
INCRM GROSS EN, MWH	88,791	101,259	114,356	121,138	121,138	124,690	124,690	124,690	124,690	116,404	83,260
MEASURE COST, k$	$28,647	$32,749	$36,968	$39,366	$39,366	$40,393	$40,393	$40,393	$40,393	$37,452	$25,685
DEF OVERHEAD, k$	$2,936	$3,391	$3,771	$3,798	$3,798	$3,971	$3,971	$3,971	$3,971	$3,946	$3,847
EXPENSE, k$	$241	$275	$311	$331	$331	$339	$339	$339	$339	$315	$216

RESIDENTIAL RETROFIT PROGRAMS 21-Apr-92

Forecast HIGH	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	
Cumulative MWa	57.8	1.2	3.2	6.3	10.3	15.3	19.5	23.7	29.3	35.3	40.3	44.3	
Winter peak savings, MW	93.2	0.0	0.8	3.0	6.4	11.5	17.1	26.7	39.4	52.7	64.1	72.6	
Summer peak savings, MW		20.5	0.0	0.2	0.7	1.4	2.4	3.5	5.6	8.4	11.4	14.0	15.9
Cum. Net MWH	506,039	10,580	28,066	54,895	89,851	134,380	170,648	207,256	256,403	309,472	353,309	387,817	
Cum. Gross MWH	519,142	11,456	30,244	58,375	94,632	140,038	176,744	213,789	263,374	316,881	361,156	396,102	
Cumulative penetration	64.9%	1.0%	2.7%	5.3%	8.6%	12.6%	16.3%	22.2%	29.8%	37.8%	44.7%	49.9%	
Deferred cost	$233,344	$3,057	$6,647	$11,358	$14,562	$17,056	$18,767	$18,829	$24,674	$26,401	$21,341	$16,440	
Expense cost	$12,417	$599	$1,453	$1,672	$2,015	$2,247	$511	$319	$368	$383	$340	$298	
Customer cost	$17,175	$2,318	$2,080	$1,785	$1,569	$1,352	($341)	($1,349)	($2,019)	($2,150)	($1,770)	($1,019)	
ESc revenue	$147,750	$98	$354	$1,009	$1,870	$2,988	$4,139	$5,002	$6,107	$7,188	$7,886	$8,212	
Incrm. Jobs Completed	151,057	2,608	4,421	6,640	8,489	10,340	9,520	15,147	19,641	20,471	17,793	13,369	

Levelized TRC	28.0		
Levelized UC	8.1	Weighted Life	26.5
UT %	36%		

Forecast HIGH	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	
Cumulative MWa	46.1	47.9	49.0	50.0	51.1	52.2	53.3	54.4	55.5	56.6	57.8	
Winter peak savings, MW	75.5	78.2	79.9	81.6	83.2	84.9	86.5	88.2	89.9	91.5	93.2	
Summer peak savings, MW		16.5	17.1	17.5	17.9	18.3	18.6	19.0	19.4	19.8	20.1	20.5
Cum. Net MWH	403,865	419,453	428,993	438,404	447,877	457,413	467,013	476,675	486,400	496,188	506,039	
Cum. Gross MWH	412,588	428,614	438,592	448,441	458,352	468,326	478,363	488,464	498,627	508,853	519,142	
Cumulative penetration	51.9%	53.7%	55.0%	56.2%	57.5%	58.7%	59.9%	61.2%	62.4%	63.7%	64.9%	
Deferred cost	$7,693	$7,362	$4,449	$4,339	$4,339	$4,339	$4,339	$4,339	$4,339	$4,339	$4,339	
Expense cost	$224	$222	$197	$196	$196	$196	$196	$196	$196	$196	$196	
Customer cost	$442	$670	$1,159	$1,212	$2,038	$2,614	$2,726	$2,394	$1,858	$816	$791	
ESc revenue	$8,076	$7,920	$7,635	$7,355	$7,111	$6,791	$6,285	$5,683	$4,963	$4,202	$3,584	
Incrm. Jobs Completed	5,006	4,782	3,263	3,189	3,189	3,189	3,189	3,189	3,189	3,189	3,189	

RESIDENTIAL RETROFIT PROGRAMS 22-Apr-92

Forecast MEDHIGH	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cumulative MWa	57.8	1.2	3.2	6.3	10.3	15.3	19.5	23.7	29.3	35.3	40.3	44.3
Winter peak savings, MW	93.2	0.0	0.8	3.0	6.4	11.5	17.1	26.7	39.4	52.7	64.1	72.6
Summer peak savings, MW	20.5	0.0	0.2	0.7	1.4	2.4	3.5	5.6	8.4	11.4	14.0	15.9
Cum. Net MWH	506,039	10,580	28,066	54,895	89,851	134,380	170,648	207,256	256,403	309,472	353,309	387,817
Cum. Gross MWH	519,142	11,456	30,244	58,375	94,632	140,038	176,744	213,789	263,374	316,881	361,156	396,102
Cumulative penetration	64.9%	1.0%	2.7%	5.3%	8.6%	12.6%	16.3%	22.2%	29.8%	37.8%	44.7%	49.9%
Deferred cost	$233,344	$3,057	$6,647	$11,358	$14,562	$17,056	$18,767	$18,829	$24,674	$26,401	$21,341	$16,440
Expense cost	$12,417	$599	$1,453	$1,672	$2,015	$2,247	$511	$319	$368	$383	$340	$298
Customer cost	$17,175	$2,318	$2,080	$1,785	$1,569	$1,352	($341)	($1,349)	($2,019)	($2,150)	($1,770)	($1,019)
ESc revenue	$147,750	$98	$354	$1,009	$1,870	$2,988	$4,139	$5,002	$6,107	$7,188	$7,886	$8,212
Incrm. Jobs Completed	151,057	2,608	4,421	6,640	8,489	10,340	9,520	15,147	19,641	20,471	17,793	13,369
Levelized TRC	28.0											
Levelized UC	8.1	Weighted Life		26.5								
UT %	36%											

Forecast MEDHIGH	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cumulative MWa	46.1	47.9	49.0	50.0	51.1	52.2	53.3	54.4	55.5	56.6	57.8
Winter peak savings, MW	75.5	78.2	79.9	81.6	83.2	84.9	86.5	88.2	89.9	91.5	93.2
Summer peak savings, MW	16.5	17.1	17.5	17.9	18.3	18.6	19.0	19.4	19.8	20.1	20.5
Cum. Net MWH	403,865	419,453	428,993	438,404	447,877	457,413	467,013	476,675	486,400	496,188	506,039
Cum. Gross MWH	412,588	428,614	438,592	448,441	458,352	468,326	478,363	488,464	498,627	508,853	519,142
Cumulative penetration	51.9%	53.7%	55.0%	56.2%	57.5%	58.7%	59.9%	61.2%	62.4%	63.7%	64.9%
Deferred cost	$7,693	$7,362	$4,449	$4,339	$4,339	$4,339	$4,339	$4,339	$4,339	$4,339	$4,339
Expense cost	$224	$222	$197	$196	$196	$196	$196	$196	$196	$196	$196
Customer cost	$442	$670	$1,159	$1,212	$2,038	$2,614	$2,726	$2,394	$1,858	$816	$791
ESc revenue	$8,076	$7,920	$7,635	$7,355	$7,111	$6,791	$6,285	$5,683	$4,963	$4,202	$3,584
Incrm. Jobs Completed	5,006	4,782	3,263	3,189	3,189	3,189	3,189	3,189	3,189	3,189	3,189

RESIDENTIAL RETROFIT PROGRAMS						23-Jan-92						
Forecast MEDLO	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cumulative MWa	57.8	1.2	3.0	5.1	7.5	10.2	12.1	14.5	17.4	21.1	25.8	31.4
Winter peak savings, MW	104.6	0.0	0.9	2.5	5.1	8.5	12.7	18.1	24.6	32.9	43.1	54.8
Summer peak savings, MW	23.1	0.0	0.2	0.6	1.1	1.9	2.8	4.0	5.4	7.3	9.5	12.2
Cum. Net MWH	506,655	10,580	26,194	44,296	65,925	89,061	105,953	127,280	152,250	184,780	226,172	274,706
Cum. Gross MWH	519,758	11,456	28,372	47,775	70,706	94,718	112,048	133,813	159,221	192,190	234,019	282,991
Cumulative penetration	69.3%	0.0%	0.6%	1.5%	2.9%	4.9%	7.4%	10.8%	14.7%	19.8%	26.3%	33.8%
Deferred cost, k$	$260,241	$3,057	$6,113	$10,140	$12,796	$14,556	$19,779	$11,407	$13,035	$16,579	$20,494	$23,439
Expense cost, k$	$8,032	$599	$726	$760	$783	$648	$327	$256	$270	$300	$333	$358
Customer cost, k$	$14,937	$2,318	$2,054	$1,901	$1,706	$1,618	($220)	($469)	($698)	($1,078)	($1,481)	($1,650)
ESc revenue, k$	$159,960	$98	$283	$745	$1,349	$2,125	$3,201	$3,662	$4,164	$4,802	$5,572	$6,356
Incrm. Jobs Completed	167,618	2,608	4,603	5,698	7,141	7,721	7,045	8,848	10,431	13,094	16,028	18,211

Levelized TRC 28.8
Levelized UC 8.5 Weighted Life 28.5
UT % 37%

RESIDENTIAL RETROFIT PROGRAMS											
Forecast MEDLO	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cumulative MWa	37.0	42.7	47.3	49.2	50.9	52.1	53.2	54.4	55.5	56.7	57.8
Winter peak savings, MW	66.8	78.7	88.4	91.3	94.0	96.1	97.8	99.5	101.2	102.9	104.6
Summer peak savings, MW	14.8	17.4	19.6	20.2	20.8	21.2	21.6	22.0	22.3	22.7	23.1
Cum. Net MWH	324,232	374,102	414,715	430,828	445,674	456,554	466,448	476,405	486,426	496,509	506,655
Cum. Gross MWH	332,955	383,263	424,314	440,865	456,149	467,467	477,799	488,194	498,653	509,174	519,758
Cumulative penetration	41.6%	49.3%	55.6%	58.2%	60.5%	62.1%	63.5%	64.9%	66.4%	67.8%	69.3%
Deferred cost, k$	$23,819	$23,819	$19,253	$7,664	$7,035	$5,088	$4,434	$4,434	$4,434	$4,434	$4,434
Expense cost, k$	$361	$361	$322	$224	$219	$202	$197	$197	$197	$197	$197
Customer cost, k$	($1,540)	($1,369)	($752)	$814	$1,078	$1,419	$1,791	$2,146	$2,430	$2,460	$2,460
ESc revenue, k$	$7,069	$7,698	$8,055	$7,889	$7,722	$7,435	$6,993	$6,489	$5,906	$5,158	$4,709
Incrm. Jobs Completed	18,628	18,628	15,198	5,139	4,829	3,770	3,293	3,293	3,293	3,293	3,293

RESIDENTIAL RETROFIT PROGRAMS

Forecast LOW	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cumulative MWa	57.9	1.2	3.0	5.1	7.5	10.1	11.9	13.8	15.9	18.1	20.7	23.5
Winter peak savings, MW	104.8	0.0	0.9	2.5	5.1	8.4	12.3	16.6	21.2	26.2	31.6	37.4
Summer peak savings, MW	23.1	0.0	0.2	0.6	1.1	1.9	2.7	3.7	4.7	5.8	7.0	8.3
Cum. Net MWH	507,421	10,580	26,194	44,296	65,925	88,770	104,165	121,152	139,410	158,952	181,481	205,949
Cum. Gross MWH	520,524	11,456	28,372	47,775	70,706	94,427	110,260	127,685	146,382	166,361	189,328	214,234
Cumulative penetration	69.4%	0.0%	0.6%	1.5%	2.9%	4.8%	7.1%	9.7%	12.6%	15.7%	19.2%	22.8%
Deferred cost, k$	$261,544	$3,057	$6,113	$10,140	$12,796	$14,556	$19,779	$9,272	$9,825	$10,378	$11,463	$11,999
Expense cost, k$	$8,043	$599	$726	$760	$783	$648	$327	$238	$242	$247	$256	$261
Customer cost, k$	$9,644	$2,318	$2,054	$1,901	$1,706	$1,629	($160)	($258)	($322)	($386)	($488)	($387)
ESc revenue, k$	$160,891	$98	$283	$745	$1,349	$2,125	$3,201	$3,533	$3,857	$4,172	$4,503	$4,774
Incrm. Jobs Completed	137,879	2,608	4,603	5,698	7,141	7,534	6,471	7,204	7,665	8,126	8,889	9,339

Levelized TRC 28.3
Levelized UC 8.5 Weighted Life 28.5
UT % 37%

RESIDENTIAL RETROFIT PROGRAMS

Forecast LOW	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cumulative MWa	26.5	29.5	32.8	36.0	39.3	42.8	46.2	49.7	53.2	56.2	57.9
Winter peak savings, MW	43.4	49.8	56.4	62.9	69.5	76.3	83.0	89.8	96.6	102.2	104.8
Summer peak savings, MW	9.6	11.0	12.5	13.9	15.4	16.9	18.4	19.9	21.4	22.6	23.1
Cum. Net MWH	231,720	258,805	287,201	315,792	344,580	374,697	405,019	435,544	466,273	492,672	507,421
Cum. Gross MWH	240,443	267,966	296,800	325,829	355,055	385,610	416,370	447,333	478,499	505,337	520,524
Cumulative penetration	26.7%	30.8%	35.2%	39.6%	44.0%	48.7%	53.4%	58.2%	63.0%	67.1%	69.4%
Deferred cost, k$	$12,536	$13,072	$13,638	$13,638	$13,638	$14,203	$14,203	$14,203	$14,203	$12,135	$6,697
Expense cost, k$	$265	$270	$275	$275	$275	$280	$280	$280	$280	$262	$216
Customer cost, k$	($316)	($207)	($112)	($16)	$71	$86	$142	$233	$288	$590	$1,278
ESc revenue, k$	$5,033	$5,279	$5,514	$5,714	$5,908	$6,042	$6,009	$5,877	$5,633	$5,130	$4,807
Incrm. Jobs Completed	9,788	10,238	10,563	10,563	10,563	10,888	10,888	10,888	10,888	9,173	4,593

FORECAST HIGH NEW RESIDENTIAL SECTOR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cum. Energy, MWa	72.6	0.3	1.2	2.3	3.8	6.6	10.5	14.7	18.7	23.3	27.7	32.1
Winter peak savings, MW	108.6	0.0	0.8	1.9	3.6	6.4	10.6	15.4	20.5	26.8	32.8	38.8
Summer peak savings, MW	39.6	0.0	0.3	0.7	1.3	2.3	3.9	5.6	7.5	9.8	12.0	14.2
Cum. Energy, MWH	635,744	2,905	10,706	19,735	33,219	57,855	92,076	128,460	163,669	203,944	242,611	281,061
Utility Def. cost	$350,092	$3,822	$6,020	$5,591	$8,273	$15,260	$21,091	$22,139	$21,446	$24,603	$23,624	$23,399
Utility expense	$39,955	$720	$716	$702	$959	$1,692	$2,138	$2,141	$1,990	$2,199	$2,111	$2,064
Customer cost	$67,062	$129	$727	$780	$1,108	$2,094	$2,908	$3,058	$3,020	$3,406	$3,334	$3,401
Incrm. MWH	633,420	581	7,801	9,030	13,483	24,636	34,221	36,384	35,209	40,275	38,667	38,450

Levelized TRC30.8
Levelized UC 25.7
UT% 11%
Weighted Life 50

PENETRATION RATES	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
OR,WA CODE	0.6	0.75	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ID SGC	0.4	0.5	0.7	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
MT SGC	0.4	0.5	0.7	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ADDED PROGRAM	0	0.15	0.25	0.35	0.45	0.55	0.65	0.75	0.85	0.85	0.85
UT,WY SGC	0	0.1	0.25	0.4	0.6	0.75	0.85	0.85	0.85	0.85	0.85
HUD MH STANDARD						1	1	1	1	1	1
SGC MH PROGRAM	0	0.3	0.4	0.5	0.75	0.85	0.85	0.85	0.85	0.85	0.85

NEW RESIDENTIAL SECTOR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cum. Energy, MWa	36.6	41.1	45.3	49.1	52.3	55.4	58.7	62.2	65.8	69.4	72.6
Winter peak savings, MW	45.3	51.8	58.1	64.1	69.8	75.5	81.6	88.4	95.2	102.1	108.6
Summer peak savings, MW	16.5	18.9	21.2	23.4	25.4	27.5	29.8	32.2	34.7	37.2	39.6
Cum. Energy, MWH	320,397	359,756	396,670	429,818	458,529	485,629	514,570	544,988	576,276	607,689	635,744
Utility Def. cost	$24,821	$25,125	$24,195	$23,182	$21,820	$21,634	$23,030	$25,268	$25,526	$25,561	$23,887
Utility expense	$2,202	$2,222	$2,131	$2,038	$1,908	$1,886	$2,003	$2,194	$2,209	$2,212	$2,064
Customer cost	$3,716	$3,747	$3,698	$3,649	$3,564	$3,612	$3,863	$4,222	$4,296	$4,406	$4,324
Incrm. MWH	39,336	39,359	36,914	33,149	28,711	27,100	28,941	30,419	31,288	31,413	28,054
PENETRATION RATES	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
OR,WA CODE	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ID SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
MT SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ADDED PROGRAM	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
UT,WY SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
HUD MH STANDARD		1	1	1	1	1	1	1	1	1	1
SGC MH PROGRAM	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85

FORECAST MEDIUM-HIGH												
NEW RESIDENTIAL SECTOR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cum. Energy, MWa	55.6	0.3	1.1	1.8	3.0	5.2	8.4	11.8	14.9	18.6	22.0	25.4
Winter peak savings, MW	83.3	0.0	0.7	1.5	2.8	5.0	8.4	12.3	16.3	21.3	26.0	30.6
Summer peak savings, MW	30.3	0.0	0.2	0.5	1.0	1.8	3.1	4.5	5.9	7.8	9.5	11.2
Cum. Energy, MWH	486,974	2,905	9,238	15,935	26,158	45,857	73,895	103,366	130,958	162,834	192,886	222,483
Utility Def. cost	$269,051	$3,822	$5,096	$4,124	$6,241	$12,192	$17,276	$17,902	$16,788	$19,459	$18,350	$17,989
Utility expense	$30,813	$720	$716	$517	$723	$1,352	$1,752	$1,731	$1,559	$1,742	$1,644	$1,608
Customer cost	$53,559	$129	$581	$565	$816	$1,652	$2,370	$2,474	$2,389	$2,723	$2,638	$2,690
Incrm. MWH	484,650	581	6,333	6,697	10,223	19,699	28,038	29,471	27,593	31,876	30,051	29,597
Levelized TRC 31.1												
Levelized UC 25.8												
UT% 11%												
Weighted Life 50												

PENETRATION RATES	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
OR,WA CODE	0.6	0.75	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ID SGC	0.4	0.5	0.7	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
MT SGC	0.4	0.5	0.7	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ADDED PROGRAM	0	0.15	0.25	0.35	0.45	0.55	0.65	0.75	0.85	0.85	0.85
UT,WY SGC	0	0.1	0.25	0.4	0.6	0.75	0.85	0.85	0.85	0.85	0.85
HUD MH STANDARD						1	1	1	1	1	1
SGC MH PROGRAM	0	0.3	0.4	0.5	0.75	0.85	0.85	0.85	0.85	0.85	0.85

FORECAST MEDIUM-HIGH											
NEW RESIDENTIAL SECTOR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cum. Energy, MWa	28.9	32.3	35.6	38.4	40.7	42.8	45.2	47.8	50.4	53.1	55.6
Winter peak savings, MW	35.6	40.7	45.4	50.0	54.1	58.3	62.8	67.8	72.9	78.3	83.3
Summer peak savings, MW	13.0	14.8	16.5	18.2	19.7	21.2	22.8	24.7	26.5	28.5	30.3
Cum. Energy, MWH	252,927	283,360	311,461	335,964	356,355	375,277	396,078	418,302	441,251	465,430	486,974
Utility Def. cost	$19,215	$19,356	$18,347	$17,260	$15,900	$15,603	$16,818	$18,789	$18,915	$19,558	$18,255
Utility expense	$1,711	$1,718	$1,622	$1,526	$1,398	$1,369	$1,473	$1,643	$1,651	$1,707	$1,593
Customer cost	$2,974	$2,989	$2,936	$2,872	$2,787	$2,820	$3,051	$3,380	$3,442	$3,657	$3,624
Incrm. MWH	30,444	30,433	28,101	24,503	20,391	18,922	20,801	22,224	22,950	24,178	21,544

PENETRATION RATES	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
OR,WA CODE	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ID SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
MT SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ADDED PROGRAM	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
UT,WY SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
HUD MH STANDARD		1	1	1	1	1	1	1	1	1	1
SGC MH PROGRAM	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85

FORECAST MEDIUM-LOW NEW RESIDENTIAL SECTOR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cum. Energy, MWa	36.6	0.3	0.7	1.6	2.8	4.3	6.1	8.2	10.2	12.3	14.2	16.1
Winter peak savings, MW	55.2	0.0	0.3	1.3	2.6	4.1	6.0	8.3	10.9	13.7	16.3	18.9
Summer peak savings, MW	20.1	0.0	0.1	0.5	1.0	1.5	2.2	3.0	4.0	5.0	5.9	6.9
Cum. Energy, MWH	320,454	2,905	5,910	14,078	24,771	37,620	53,725	71,766	89,440	107,530	124,398	140,849
Utility Def. cost	$175,824	$101	$8,046	$4,329	$5,514	$6,571	$7,989	$8,716	$8,496	$8,649	$8,096	$7,884
Utility expense	$20,169	$13	$742	$642	$765	$854	$952	$1,014	$968	$967	$906	$883
Customer cost	$34,922	$129	$283	$673	$816	$1,033	$1,354	$1,536	$1,541	$1,620	$1,542	$1,579
Incrm. MWH	318,130	581	3,005	8,168	10,693	12,848	16,105	18,041	17,674	18,090	16,868	16,451

Levelized TRC 30.9
Levelized UC 25.6
UT% 12%
Weighted Life 50

PENETRATION RATES	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
OR,WA CODE	0.6	0.75	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ID SGC	0.4	0.5	0.7	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
MT SGC	0.4	0.5	0.7	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ADDED PROGRAM	0	0.15	0.25	0.35	0.45	0.55	0.65	0.75	0.85	0.85	0.85
UT,WY SGC	0	0.1	0.25	0.4	0.6	0.75	0.85	0.85	0.85	0.85	0.85
HUD MH STANDARD						1	1	1	1	1	1
SGC MH PROGRAM	0	0.3	0.4	0.5	0.75	0.85	0.85	0.85	0.85	0.85	0.85

FORECAST MEDIUM-LOW NEW RESIDENTIAL SECTOR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cum. Energy, MWa	18.1	19.9	21.8	23.7	25.3	27.1	29.0	31.1	33.0	34.8	36.6
Winter peak savings, MW	21.8	24.6	27.7	30.9	33.7	37.0	40.5	44.4	48.2	51.7	55.2
Summer peak savings, MW	7.9	8.9	10.0	11.2	12.2	13.4	14.7	16.1	17.5	18.8	20.1
Cum. Energy, MWH	158,499	173,989	190,615	207,854	221,542	237,254	253,726	272,068	289,506	305,004	320,454
Utility Def. cost	$8,728	$8,287	$9,189	$9,581	$8,308	$9,572	$10,159	$11,286	$10,721	$9,724	$9,926
Utility expense	$976	$924	$1,024	$1,067	$924	$1,058	$1,123	$1,245	$1,181	$1,071	$1,090
Customer cost	$1,828	$1,770	$1,906	$1,979	$1,842	$2,019	$2,151	$2,375	$2,302	$2,270	$2,374
Incrm. MWH	17,651	15,490	16,626	17,239	13,687	15,712	16,472	18,342	17,438	15,498	15,450

PENETRATION RATES	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
OR,WA CODE	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ID SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
MT SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ADDED PROGRAM	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
UT,WY SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
HUD MH STANDARD	1	1	1	1	1	1	1	1	1	1	1
SGC MH PROGRAM	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85

FORECAST LOW

NEW RESIDENTIAL SECTOR	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cum. Energy, MWa	19.7	0.3	0.5	1.2	2.1	3.0	4.2	5.5	6.7	7.8	8.8	9.7
Winter peak savings, MW	30.4	0.0	0.2	0.9	1.8	2.7	3.9	5.4	6.9	8.5	9.9	11.2
Summer peak savings, MW	11.0	0.0	0.1	0.3	0.7	1.0	1.4	2.0	2.5	3.1	3.6	4.1
Cum. Energy, MWH	172,577	2,905	4,723	10,726	18,236	26,388	36,673	48,129	58,505	68,593	77,253	85,288
Utility Def. cost	$97,343	$3,822	$2,125	$3,751	$4,640	$4,878	$6,010	$6,673	$6,148	$6,061	$5,235	$4,861
Utility expense	$11,315	$720	$716	$470	$536	$534	$594	$631	$561	$538	$468	$437
Customer cost	$20,413	$129	$149	$454	$515	$599	$829	$961	$909	$936	$840	$854
Incrm. MWH	170,253	581	1,818	6,003	7,510	8,152	10,286	11,456	10,376	10,088	8,660	8,034
Levelized TRC 32.1												
Levelized UC 26.4												
UT% 13%												
Weighted Life 50												

PENETRATION RATES	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
OR,WA CODE	0.6	0.75	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ID SGC	0.4	0.5	0.7	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
MT SGC	0.4	0.5	0.7	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ADDED PROGRAM	0	0.15	0.25	0.35	0.45	0.55	0.65	0.75	0.85	0.85	0.85
UT,WY SGC	0	0.1	0.25	0.4	0.6	0.75	0.85	0.85	0.85	0.85	0.85
HUD MH STANDARD						1	1	1	1	1	1
SGC MH PROGRAM	0	0.3	0.4	0.5	0.75	0.85	0.85	0.85	0.85	0.85	0.85

FORECAST LOW

NEW RESIDENTIAL SECTOR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cum. Energy, MWa	10.8	11.6	12.5	13.5	14.1	14.9	15.8	16.9	17.8	18.8	19.7
Winter peak savings, MW	12.7	14.1	15.8	17.5	18.8	20.5	22.3	24.5	26.5	28.4	30.4
Summer peak savings, MW	4.6	5.1	5.7	6.3	6.8	7.4	8.1	8.9	9.6	10.3	11.0
Cum. Energy, MWH	94,425	101,596	109,706	118,242	123,402	130,479	138,253	147,719	156,307	164,379	172,577
Utility Def. cost	$5,754	$5,201	$6,073	$6,302	$4,651	$6,042	$6,558	$7,706	$6,989	$6,561	$6,912
Utility expense	$515	$465	$542	$564	$417	$530	$578	$676	$613	$579	$608
Customer cost	$1,067	$1,002	$1,097	$1,130	$976	$1,113	$1,210	$1,382	$1,299	$1,424	$1,537
Incrm. MWH	9,137	7,171	8,110	8,535	5,160	7,077	7,774	9,466	8,589	8,072	8,198

PENETRATION RATES	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
OR,WA CODE	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ID SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
MT SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
ADDED PROGRAM	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
UT,WY SGC	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
HUD MH STANDARD		1	1	1	1	1	1	1	1	1	1
SGC MH PROGRAM	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85

APPLIANCE PROGRAM FORECAST HIGH	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cum. savings, MWa	28.2	0.0	0.0	0.2	0.8	1.8	5.5	11.2	16.7	21.4	25.2	27.1
Cum. Winter Peak, MW	47.0	0.0	0.0	0.4	1.3	2.9	9.2	18.6	27.8	35.6	42.0	45.2
Cum. Summer Peak, MW	47.0	0.0	0.0	0.4	1.3	2.9	9.2	18.6	27.8	35.6	42.0	45.2
Cumulative No. Homes	301,069	0	428	4,409	15,335	34,903	86,432	152,367	208,576	251,897	283,148	295,329
Cum. MWH	246,813	0	186	1,909	6,663	15,347	48,607	97,852	145,882	187,055	220,571	237,579
Utility Cost	$61,805	$0	$71	$663	$1,844	$3,382	$9,568	$12,843	$11,613	$9,583	$7,414	$3,146
Utility Expense	$2,377	$0	$3	$26	$71	$130	$368	$494	$447	$369	$285	$121
Customer cost	$12,928	$0	($26)	($240)	($665)	($1,210)	($4,756)	($7,005)	($6,738)	($5,698)	($4,607)	($2,332)
Customer payments	$9,032	$0	$13	$119	$328	$587	$1,546	$1,978	$1,686	$1,300	$938	$365
Jobs Completed	301,069	0	428	3,981	10,926	19,568	51,528	65,935	56,209	43,321	31,251	12,181

Levelized TRC	23.4
Levelized UC	16.8
UT %	36%

Assumptions			
Specific cost	$157	Expense adder=	5%
Specific yield	822	Def overhead adder=	30%
Customer cost	$41		
Customer payment	$30		

APPLIANCE PROGRAM FORECAST HIGH	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cum. savings, MWa	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2
Cum. Winter Peak, MW	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
Cum. Summer Peak, MW	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
Cumulative No. Homes	301,069	301,069	301,069	301,069	301,069	301,069	301,069	301,069	301,069	301,069	301,069
Cum. MWH	246,813	246,813	246,813	246,813	246,813	246,813	246,813	246,813	246,813	246,813	246,813
Utility Cost	$1,676	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility Expense	$64	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer cost	($771)	$1,419	$2,601	$7,360	$9,879	$8,933	$7,372	$5,703	$2,420	$1,289	$0
Customer payments			$172	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	5,740	0	0	0	0	0	0	0	0	0	0

APPLIANCE PROGRAM

FORECAST MEDHIGH	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cum. savings, MWa	27.7	0.0	0.0	0.2	0.8	1.7	5.5	11.0	16.4	21.0	24.8	26.6
Cum. Winter Peak, MW	46.1	0.0	0.0	0.4	1.3	2.9	9.1	18.4	27.4	35.0	41.3	44.4
Cum. Summer Peak, MW	46.1	0.0	0.0	0.4	1.3	2.9	9.1	18.4	27.4	35.0	41.3	44.4
Cumulative No. Homes	294,986	0	425	4,369	15,187	34,537	85,446	150,414	205,536	247,739	277,937	289,601
Cum. MWH	242,332	0	184	1,888	6,586	15,158	48,008	96,566	143,800	184,148	216,865	233,415
Utility Cost	$60,114	$0	$70	$654	$1,815	$3,321	$9,398	$12,576	$11,311	$9,269	$7,115	$3,006
Utility Expense	$2,312	$0	$3	$25	$70	$126	$361	$484	$435	$356	$274	$116
Customer cost	$12,220	$0	($26)	($238)	($659)	($1,195)	($4,702)	($6,914)	($6,632)	($5,589)	($4,500)	($2,273)
Customer payments	$8,850	$0	$13	$118	$325	$581	$1,527	$1,949	$1,654	$1,266	$906	$350
Jobs Completed	294,986	0	425	3,944	10,818	19,350	50,909	64,969	55,121	42,203	30,198	11,665

Levelized TRC	23.1	Assumptions			
Levelized UC	16.6	Specific cost	$157	Expense adder=	5%
UT %	36%	Specific yeild	822	Def overhead adder=	30%
		Customer cost	$41		
		Customer payment	$30		

APPLIANCE PROGRAM

FORECAST MEDHIGH	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cum. savings, MWa	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7
Cum. Winter Peak, MW	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1
Cum. Summer Peak, MW	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1
Cumulative No. Homes	294,986	294,986	294,986	294,986	294,986	294,986	294,986	294,986	294,986	294,986	294,986
Cum. MWH	242,332	242,332	242,332	242,332	242,332	242,332	242,332	242,332	242,332	242,332	242,332
Utility Cost	$1,578	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility Expense	$61	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer cost	($737)	$1,396	$2,555	$7,229	$9,674	$8,701	$7,130	$5,473	$2,312	$1,214	$0
Customer payments	$162	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	5,385	0	0	0	0	0	0	0	0	0	0

APPLIANCE PROGRAM FORECAST MEDIUM LOW	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cum. savings, MWa	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.7	1.7
Cum. Winter Peak, MW	25.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	1.2	2.9
Cum. Summer Peak, MW	25.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	1.2	2.9
Cumulative No. Homes	165,418	0	420	420	420	420	420	420	718	2,531	9,263	21,110
Cum. MWH	131,743	0	182	182	182	182	182	182	346	1,401	6,199	15,150
Utility Cost	$37,135	$0	$69	$0	$0	$0	$0	$0	$96	$442	$1,860	$3,485
Utility Expense	$1,428	$0	$3	$0	$0	$0	$0	$0	$4	$17	$72	$134
Customer cost	($2,822)	$0	($25)	$0	$0	$0	$0	$0	($23)	($134)	($632)	($1,112)
Customer payments	$4,963	$0	$13	$0	$0	$0	$0	$0	$9	$54	$202	$355
Jobs Completed	165,418	0	420	0	0	0	0	0	298	1,813	6,732	11,847

Levelized TRC	20.4	Assumptions				
Levelized UC	19.1	Specific cost	$173	Expense adder=	5%	
UT %	45%	Specific yeild	796	Def overhead adder=	30%	
		Customer cost	($17)			
		Customer payment	$30			

APPLIANCE PROGRAM FORECAST MEDIUM LOW		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011/2012
Cum. savings, MWa	3.8	6.2	8.6	10.3	11.1	11.9	12.6	13.4	14.2	14.6	15.0
Cum. Winter Peak, MW	6.4	10.3	14.3	17.2	18.6	19.8	21.0	22.3	23.6	24.3	25.1
Cum. Summer Peak, MW	6.4	10.3	14.3	17.2	18.6	19.8	21.0	22.3	23.6	24.3	25.1
Cumulative No. Homes	37,953	52,200	66,624	81,150	95,360	110,059	125,065	140,619	155,982	160,568	165,418
Cum. MWH	33,456	53,974	75,398	90,382	97,589	103,857	110,337	117,230	123,979	127,767	131,743
Utility Cost	$5,249	$5,096	$5,236	$4,846	$1,354	$1,440	$1,508	$1,664	$1,608	$1,553	$1,629
Utility Expense	$202	$196	$201	$186	$52	$55	$58	$64	$62	$60	$63
Customer cost	($2,403)	($2,608)	($2,800)	($2,047)	($580)	($381)	($142)	$896	$2,170	$3,566	$3,433
Customer payments			$505	$427	$433	$436	$426	$441	$450	$467	[illegible]
Jobs Completed	16,842	14,247	14,425	14,526	14,210	14,698	15,006	15,554	15,363	4,585	4,850

APPLIANCE PROGRAM FORECAST LOW	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cum. savings, MWa	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cum. Winter Peak, MW	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Cum. Summer Peak, MW	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Cumulative No. Homes	35,199	0	406	406	406	406	406	406	662	662	662	662
Cum. MWH	19,466	0	177	177	177	177	177	177	319	319	319	319
Utility Cost	$4,417	$0	$68	$0	$0	$0	$0	$0	$85	$0	$0	$0
Utility Expense	$170	$0	$3	$0	$0	$0	$0	$0	$3	$0	$0	$0
Customer cost	($1,481)	$0	($25)	$0	$0	$0	$0	$0	($20)	$0	$0	$52
Customer payments			$1,056	$0	$12	$0	$0	$0	$0	$0	$8	$0
Jobs Completed	35,199	0	406	0	0	0	0	0	256	0	0	0

Levelized TRC	12.0	Assumptions			
Levelized UC	13.6	Specific cost	$96	Expense adder=	5%
UT %	60%	Specific yeild	553	Def overhead adder=	30%
		Customer cost	($42)		
		Customer payment	$30		

APPLIANCE PROGRAM FORECAST LOW	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cum. savings, MWa	0.0	0.0	0.0	0.1	0.1	0.2	0.5	1.0	1.7	2.0	2.2
Cum. Winter Peak, MW	0.1	0.1	0.1	0.1	0.2	0.3	0.8	1.6	2.8	3.3	3.7
Cum. Summer Peak, MW	0.1	0.1	0.1	0.1	0.2	0.3	0.8	1.6	2.8	3.3	3.7
Cumulative No. Homes	662	662	662	942	1,777	3,460	8,001	17,265	30,386	32,685	35,199
Cum. MWH	319	319	319	522	918	1,694	4,047	8,613	14,635	17,204	19,466
Utility Cost	$0	$0	$0	$97	$64	$144	$365	$802	$929	$914	$949
Utility Expense	$0	$0	$0	$4	$2	$6	$14	$31	$36	$35	$37
Customer cost	$0	$0	$0	($24)	($17)	$29	($161)	($312)	($403)	($323)	($277)
Customer payments			$0	$0	$0	$8	$25	$50	$136	$278	[illegible]
Jobs Completed	0	0	0	280	835	1,683	4,541	9,264	13,121	2,299	2,514

WATER HEATER CONTROLLER PROGRAM FORECAST HIGH	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cumulative MWa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter peak savings, MW	224.8	0.0	0.0	0.0	0.6	3.7	30.0	84.4	147.8	209.2	224.8	224.8
Summer peak savings, MW	134.9	0.0	0.0	0.0	0.4	2.2	18.0	50.6	88.7	125.5	134.9	134.9
Cum. MWH	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative penetration	19.6%	0.0%	0.0%	0.0%	0.1%	0.4%	2.8%	8.1%	14.3%	20.4%	22.2%	22.4%
Deferred cost	$57,437,783	$0	$0	$0	$155,877	$824,191	$6,725,775	$13,908,009	$16,194,522	$15,668,384	$3,961,026	$0
Expense cost	$75,072,397	$0	$0	$0	$20,006	$118,795	$945,053	$2,428,333	$3,882,818	$5,167,180	$4,972,536	$4,794,806
Customer cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESc revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	199,784	0	0	0	542	2,867	23,394	48,376	56,329	54,499	13,777	0

Levelized TRC	$53.84	Overhead adder=	15%
Levelized UC	$53.84	Expense adder=	5%
UT %	13%		

WATER HEATER CONTROLLER PROGRAM FORECAST HIGH	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cumulative MWa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter peak savings, MW	224.8	224.8	224.8	224.8	224.8	224.8	224.8	224.8	224.8	224.8	224.8
Summer peak savings, MW	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9
Cum. MWH	0	0	0	0	0	0	0	0	0	0	0
Cumulative penetration	22.6%	22.8%	23.1%	23.3%	22.9%	22.4%	22.0%	21.5%	21.1%	20.6%	20.2%
Deferred cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Expense cost	$4,794,806	$4,794,806	$4,794,806	$4,794,806	$4,794,806	$4,794,806	$4,794,806	$4,794,806	$4,794,806	$4,794,806	$4,794,806
Customer cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESc revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	0	0	0	0	0	0	0	0	0	0	0

WATER HEATER CONTROLLER PROGRAM 14-Jan-92

FORECAST MEDIUM HIGH	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cumulative MWa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter peak savings, MW	212.8	0.0	0.0	0.0	0.6	3.6	28.6	80.4	140.3	198.1	212.8	212.8
Summer peak savings, MW	127.7	0.0	0.0	0.0	0.3	2.1	17.2	48.2	84.2	118.9	127.7	127.7
Cum. MWH	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative penetration	18.6%	0.0%	0.0%	0.0%	0.1%	0.4%	2.8%	8.0%	14.1%	20.3%	22.2%	22.6%
Deferred cost	$54,366,402	$0	$0	$0	$149,977	$786,111	$6,418,639	$13,224,692	$15,318,132	$14,741,336	$3,727,514	$0
Expense cost	$71,085,230	$0	$0	$0	$19,249	$113,416	$901,961	$2,311,320	$3,683,983	$4,888,684	$4,705,665	$4,538,413
Customer cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESc revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	189,101	0	0	0	522	2,734	22,326	45,999	53,280	51,274	12,965	0

Levelized TRC	$53.85	Overhead adder=	15%
Levelized UC	$53.85	Expense adder=	5%
UT %	13%		

WATER HEATER CONTROLLER PROGRAM

FORECAST MEDIUM HIGH	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cumulative MWa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter peak savings, MW	212.8	212.8	212.8	212.8	212.8	212.8	212.8	212.8	212.8	212.8	212.8
Summer peak savings, MW	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7	127.7
Cum. MWH	0	0	0	0	0	0	0	0	0	0	0
Cumulative penetration	22.9%	23.3%	23.7%	24.2%	23.9%	23.6%	23.2%	22.9%	22.5%	22.1%	21.7%
Deferred cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Expense cost	$4,538,413	$4,538,413	$4,538,413	$4,538,413	$4,538,413	$4,538,413	$4,538,413	$4,538,413	$4,538,413	$4,538,413	$4,538,413
Customer cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESc revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	0	0	0	0	0	0	0	0	0	0	0

WATER HEATER CONTROLLER PROGRAM 23-Jan-92

FORECAST MEDIUM LOW	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cumulative MWa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter peak savings, MW	213.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	4.3	30.2
Summer peak savings, MW	127.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	2.6	18.1
Cum. MWH	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative penetration	18.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.5%	3.5%
Deferred cost	$54,493,696	$0	$0	$0	$0	$0	$0	$0	$0	$180,165	$941,232	$6,652,161
Expense cost	$48,626,307	$0	$0	$0	$0	$0	$0	$0	$0	$23,124	$135,845	$947,403
Customer cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESc revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	189,543	0	0	0	0	0	0	0	0	627	3,274	23,138

Levelized TRC	$44.19	Overhead adder=	15%
Levelized UC	$44.19	Expense adder=	5%
UT %	16%		

WATER HEATER CONTROLLER PROGRAM

FORECAST MEDIUM LOW	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cumulative MWa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter peak savings, MW	82.2	142.0	198.4	213.1	213.1	213.1	213.1	213.1	213.1	213.1	213.1
Summer peak savings, MW	49.3	85.2	119.1	127.9	127.9	127.9	127.9	127.9	127.9	127.9	127.9
Cum. MWH	0	0	0	0	0	0	0	0	0	0	0
Cumulative penetration	9.8%	17.4%	25.0%	27.6%	27.4%	27.1%	26.8%	26.5%	26.2%	25.9%	25.6%
Deferred cost	$13,293,260	$15,296,883	$14,393,372	$3,736,624	$0	$0	$0	$0	$0	$0	$0
Expense cost	$2,355,084	$3,721,943	$4,882,936	$4,716,700	$4,549,039	$4,549,039	$4,549,039	$4,549,039	$4,549,039	$4,549,039	$4,549,039
Customer cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESc revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	46,237	53,207	50,064	12,997	0	0	0	0	0	0	0

WATER HEATER CONTROLLER PROGRAM

23-Jan-92

FORECAST LOW	TOTAL	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Cumulative MWa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter peak savings, MW	204.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer peak savings, MW	122.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cum. MWH	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative penetration	18.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Deferred cost	$52,282,238	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Expense cost	$16,265,329	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESc revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	4,551	0	0	0	0	0	0	0	0	0	0	0

Levelized TRC	$30.64	Overhead adder=	15%
Levelized UC	$30.64	Expense adder=	5%
UT %	18%		

WATER HEATER CONTROLLER PROGRAM

FORECAST LOW	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cumulative MWa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter peak savings, MW	0.0	0.0	0.0	0.0	0.8	5.0	30.8	80.9	138.0	191.0	204.3
Summer peak savings, MW	0.0	0.0	0.0	0.0	0.5	3.0	18.5	48.5	82.8	114.6	122.6
Cum. MWH	0	0	0	0	0	0	0	0	0	0	0
Cumulative penetration	0.0%	0.0%	0.0%	0.0%	0.1%	0.7%	4.5%	11.6%	19.8%	27.3%	29.1%
Deferred cost	$0	$0	$0	$0	$214,291	$1,094,211	$6,624,561	$12,815,590	$14,620,562	$13,518,215	$3,394,809
Expense cost	$0	$0	$0	$0	$27,504	$158,328	$959,479	$2,307,091	$3,608,579	$4,687,594	$4,516,754
Customer cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESc revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jobs Completed	0	0	0	0	745	3,806	23,042	44,576	50,854	47,020	11,808

PACIFICORP
CONSERVATION SUPPLY CURVE PROJECT
TECHNICAL DOCUMENTATION

SUMMARY

PacifiCorp initiated a project to define conservation supply curves for planning purposes during RAMPP-1. The basic methodology builds on supply curves developed by the Northwest Power Planning Council. For the current RAMPP-2 study, the supply curves have been updated to reflect Pacific's service territory and building stock. This document details planning assumptions and methodology.

The supply curves are designed for easy maintenance and transparent assumptions. They are produced with a series of linked LOTUS 123 spreadsheets. Since PacifiCorp territory covers a range of states and climates, there are a large number of sheets -- about 400. The model is less complicated than it sounds because of the modular nature of the spreadsheets. It is easy to update a portion of the data without redoing all the calculations.

The supply curves estimate the technical potential for conservation. This is a large number. It is intended to reflect the physical possibilities of conservation measures, without considering marketing limitations. The constraints of marketing will reduce the amount of conservation that can be realistically captured by programs. The spreadsheets can also be used to estimate programmatic potential, if penetration rates are specified.

It is assumed that the forecast is based on a "frozen efficiency" assumption. The supply curves can be used to estimate the amount of background conservation or "gravity" that customers would be expected to do on their own. The background is based on the assumption that a 60% implicit discount rate reflects the customer's barriers. Under this assumption the amount of background conservation is large only in commercial sector, where savings are expected to be low-cost.

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1. COMPANY BACKGROUND

Historic sales information is listed in Table 1 and Table 2 for 1990, the most recent year with full data available. Industrial customers account for the largest amount of sales, with commercial and residential splitting most of the rest. Utah has a large and diversified industrial base. In the Northwest, Oregon accounts for about half of sales. Wyoming is also a strong region, based on mining and petroleum.

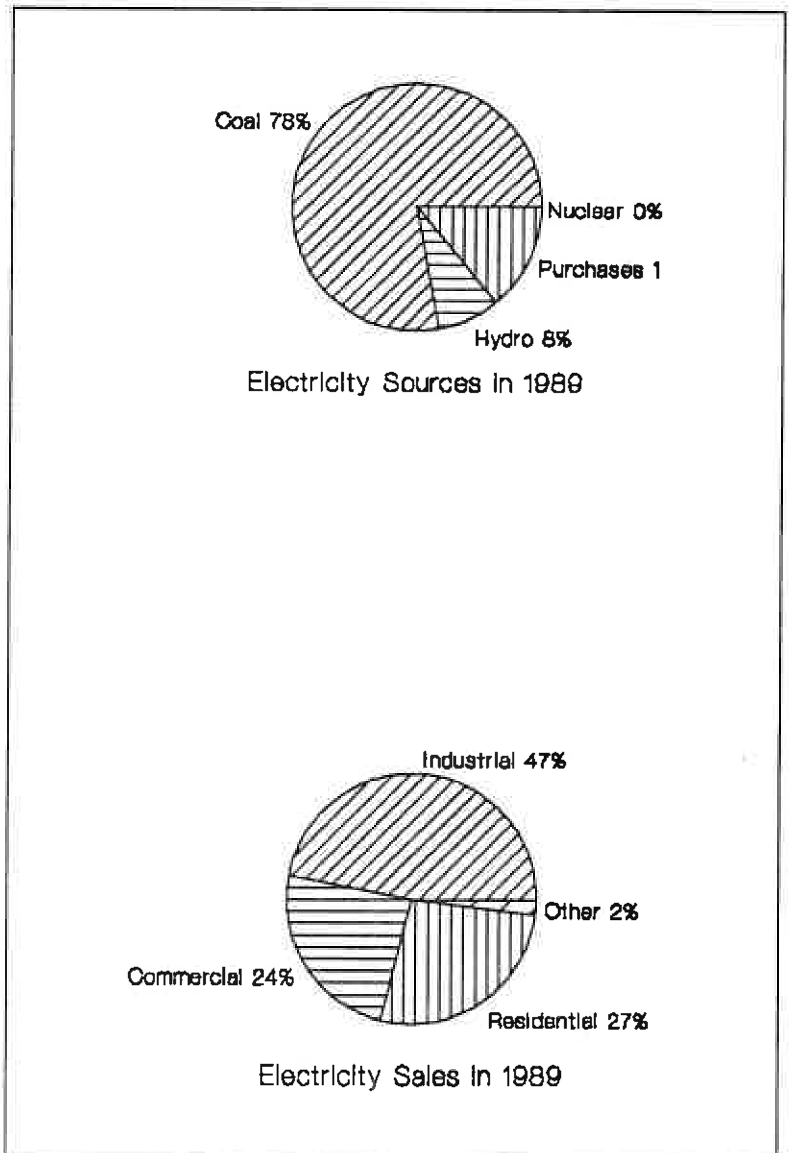


Figure 1 Sources and Sales

Table 1 Number of Customers

NUMBER OF CUSTOMERS

	COMPANY	OREGON	WASH.	IDAHO (P)	MONT.	WYOMING (P)	CALIF.	IDAHO (U)	WYOMING (U)	UTAH	PPL TOTAL	UPL TOTAL
RESIDENTIAL	1,054,454	350,373	87,454	7,236	24,433	81,790	29,809	35,577	8,998	428,784	581,095	473,359
COMMERCIAL	140,302	52,413	12,613	1,452	4,523	15,555	6,122	4,667	1,747	41,210	92,678	47,624
INDUSTRIAL	11,548	1,833	514	111	150	2,005	118	793	360	5,664	4,731	6,817
IRRIGATION	9,929	3,638	2,630	8	48	298	806	1,533	13	955	7,428	2,501
OTHER	2,639	352	121	9	38	114	88	86	53	1,778	722	1,917
TOTALS	1,218,872	408,609	103,332	8,816	29,192	99,762	36,943	42,656	11,171	478,391	686,654	532,218
% OF TOTAL		33.5%	8.5%	0.7%	2.4%	8.2%	3.0%	3.5%	0.9%	39.2%	56.3%	43.7%

Table 2 Historical Company Sales

CUSTOMER SALES (MWh) 1989

	COMPANY	OREGON	WASHINGTON	IDAHO (P)	MONTANA	WYOMING	CALIFORNIA	IDAHO (U)	WYOMING	UTAH
RESIDENTIAL	10,765,281	4,360,171	1,296,442	96,309	281,396	669,850	330,666	522,934	81,923	3,125,590
COMMERCIAL	8,803,028	3,181,426	964,376	59,017	201,008	787,383	191,237	174,997	83,998	3,159,586
INDUSTRIAL	18,877,758	4,152,028	910,485	57,625	302,050	4,151,482	180,774	2,118,579	1,789,758	5,214,977
OTHER	699,825	44,190	7,426	727	2,178	11,388	2,292	1,771	1,526	628,327
TOTAL	39,145,892	11,737,815	3,178,729	213,678	786,632	6,620,103	704,969	2,818,281	1,957,205	12,128,480

1.1. Sector Definition

Commercial and industrial sectors were subdivided based on the following groupings. The VMS number is used by Market Assessment Services to identify the market Segments. Notice that the C/T/U, Services and Other Health were treated as small office buildings and combined with the Office category. The Other category for industrial sector includes all other segments not previously identified. Recognize that industries in these segments are not small merely because the segment is not explicitly identified.

VMS	Commercial Segment		SIC Codes
10	Office		4310-20,6010-7010,9000-10000
1	inc.	Comm/Trans/Util	4000-4220,4230-40,4410-4620, 4710-4970
11		Services	7200-8009,8110-20,8320-30, 8350-60,8390-8700,8910-9000
9		Other Health	8010-50,8070-8100
3	Retail		5200-5409,5440-50,5510-6000
2	Grocery		5410-5440,5450-5500
6	Lodging		7010-7050,8360-8370
5	Warehouse		4990-5200,4220-4230
4	Restaurant & Fast Food		5810-20
7	School		8210-8300,8330-8350
8	Hospital		8050-70
12	Other Structures		1-3999,4970-80,8810-20

Industrial Sector	SIC Code
Oil & Gas	13
Mining	12,14,109-147
inc. Coal	12
Vermiculite	14
Uranium	109
Bentonite	145
Trona	147
Food Processing	20
Lumber	24
Pulp and Paper	26
Chemicals	28
Petroleum Refining	29
Primary Metals	33
Pipelines	46
Other Manufacturing	--

1.2. Financial Parameters

Costs were computed in real terms to avoid the complexities introduced by various inflation assumptions. The primary comparison of measures is on the basis of their levelized lifecycle cost in mills/KWh. This avoids concerns about differing lifetimes. There is some problem if certain components have one lifetime and other components have another. In this event, we must calculate an effective present value of the installation cost, taking into account replacement costs. This procedure needed to be applied in only a few cases, such as calculating the present value of O&M savings.

The financial parameters used were as follows:

Discount Rate

Company's post-tax cost of capital -- 9.54%

Inflation, DRI 20 year forecast -- 5.1%

Effective real discount rate

$$r' = \frac{(1 + r)}{(1 + i)} - 1 = 4.22\%$$

The discount rate assumes a real cost of capital close to that used by other regional planners. Bonneville and the NPPC use 3% real as a societal discount rate. The capital recovery factors (CRF) are compared below:

	10 year	30 year	70 year
CRF @ 3%	.1172	.0510	.0343
CRF @ 4.22%	.1245	.0594	.0447
Relative increase	6.2%	16.5%	30.3%

1.3. Capacity Savings

The supply curve spreadsheets are established strictly to account for energy savings. However, the Energy Conservation Measures (ECM's) usually provide the additional benefit of capacity savings as well. The amount of capacity benefit depends on the type of measure and its likelihood of contributing during times of system peak. For example, commercial lighting measures will likely be in effect during system peak and will provide significant demand savings. On the other hand, residential weatherization has a much lower impact on peak. This is because the size of the residential furnace is not changed -- it still comes on with a demand spike on a winter's morning. The duration of that spike is less and so there are demand savings, but the relative impact is not as large as the energy savings. Assumptions about capacity savings will be documented for each market segment. However, the results in terms of capacity savings will be listed primarily in the Program Documentation.

Capacity calculations often rely on the Conservation Load Factor. Peak savings can be computed from the relation:

$$\text{Peak Savings (kW)} = \frac{\text{Energy Savings (kWh)/ No. of hours}}{\text{Conservation Load Factor}}$$

The peak impacts of interest are January and August representing winter and summer peaking. To calculate the peak savings, it is also necessary to estimate the energy savings relevant to that particular season. However, the supply curves are based on annual energy savings. To adjust for savings in a specific month, it is necessary to apply a "seasonality factor" defined as the fraction of annual savings that occur within the month. This process is used for estimating commercial sector savings as described in Section 4.3.

2. RESIDENTIAL SECTOR -- SPACE HEATING

2.1. Prototype Selection

For space heating, the residential building stock, both existing and new, is allocated to a set of prototype homes. There are three single family (SFD) prototypes, one or two manufactured home (MFD) prototypes and one multifamily prototype. These prototypes are taken from the planning models of the Northwest Power Planning Council. The basic methodology relies on the assumption that only three prototype homes can serve to represent all the residential stock. The homes have been modeled using SUNDAY over a range of different UA values. In the region of interest, the modeled energy usage appears to be a linear function of UA. Hence, the slope and intercept listed in the data sheet. The linear format simplifies energy calculations since one has only to multiply delta UA times slope to obtain the change in energy usage. Non-linearity does creep in as the UA becomes small (around 200 BTU/hr deg F). Such a small UA is unlikely to be encountered except perhaps in small manufactured homes. The existing stock is slowly decreasing due to a small demolition rate. Our breakdown of the housing stock, as an example, is:

	Fraction of Existing Stock	Fraction of New Stock
Residential		
Small SFD	.170	.258
Medium SFD	.251	.125
Large SFD	.191	.118
Small MFD	.200	.113
Large MFD	---	.187
Multifamily	.187	.199

2.2. Calculation of Building UA

For existing buildings, UA values were calculated based on survey information regarding existing insulation levels and the retrofit U values developed by Bonneville. This leads to some complications because the UA values used by Bonneville were empirically derived R values for different insulation measures. As a result, the incremental R changes are not strictly additive. Thus, for example, an empty ceiling (no insulation) has a U value of 0.285 or an R value of 3.5. One might expect that adding R-38 insulation would raise the R value to R-41. But this is not the case. Bonneville uses a final U value for a R-38 ceiling of 0.039 or an R value of 25.6. The difference represents empirical value of insulation on a retrofit basis with attendant voids, gaps and other installation imperfections.

Mean insulation values are used based on whatever survey information exists or informed judgement when necessary. The existing mean UA is shown as the base in the attached worksheets. Incremental changes in UA are shown for each measure, however, it must be recognized that each measure does not apply to every home. The acceptance factor shown in the worksheet list the fraction of the homes for which the measure would be appropriate. Limitations on measure acceptance are primarily that the measure is already present, or in some cases, there are physical barriers that prevent installation.

The survey data for Oregon Zone 1 comes from the Oregon Department of Energy (ODOE) survey of pre-1979 housing conducted by Bardsley Haslicher. PP&L sample was used for Zone 1. Zone 2 suffers from a small sample size in the ODOE study. Instead, values for Zone 2 were computed from unpublished Hood River Conservation Project (HRCP) data. The HRCP information on pre-retrofit conditions in Hood River was assumed to represent Zones 2 and 3.

The amount of interim stock for the period 1980-1987 is known from historic data. In most area, this is a relatively small amount because economic conditions have not encouraged new construction. The amount of the building stock from the interim time period ranges from about 8% in the Willamette Valley to about 16% in Idaho. The UA values were adjusted by assuming that new construction conformed with new energy efficiency codes. This is an optimistic assumption but should have little effect on estimates due to the small amount of recent construction. To adjust for the recent construction, the existing housing stock was grouped into "bins" representing insulation levels. A fraction equivalent to recent construction was removed form the lowest bin and transferred to the highest bin to represent the effect of recent construction on aggregate insulation level. Thus, if 20% of the homes had no wall insulation in the older population of homes and 8% of the population represents recent construction, it was assumed that a total of 88% are in the fully insulated bin and only 12% of the current stock have no wall insulation.

For new construction, building UA values were taken from the Council's spreadsheets. They represent a synthesis of recent work conducted by Bonneville and the Council staff.

2.3. Climate Zones

Some of the states span more than one climate zone. The homes were apportioned to zones using the following fractions:

Oregon Zone 1	0.8512	Oregon Zone 2	0.1488
California Zone 1	0.8587	California Zone 2	0.1414

2.4. Calibration of Model to Historic Sales

Calibration of the existing building stock model to base year sales proceeds as follows:

1. Estimate amount of residential sales due to space heat consumption.

Note that, unlike the Northwest Power Planning Council (NPPC), the Company includes the consumption of customers with partial wood heat. This is because most of our residential customers live in small town or rural areas. They tend to have a wood stove and obtain some space heating from it.

Average temperature-adjusted residential sales and average space heat consumption are shown below. The estimate of space heat is derived from two sources. One source is the Base Load study. This study looks at a three-way comparison of total consumption for electric/gas/wood heated customers. From this comparison an estimate is derived for electric space heat and the contribution of wood heat to space heating.

The second source is a conditional demand study. In this study, consumption is analyzed for a sample of customers where appliance saturations have been determined. Dummy variables are assigned for the presence of various appliances and consumption is regressed against the explanatory variables. Results of the method are shown below in Table 3.

The conditional demand model is the preferred method for disaggregating space and water heating. Its application for other appliances can be problematic because it tends to pick up other consumption which correlates with the appliance. For example, the conditional demand model yields a high value for a hot tub, probably because of other consumption associated with the income level and demographics associated with hot tub owners.

2. Adjust prototype models to agree with actual usage.

Table 3 Existing Residential Space Heat

							UP&L		
ACTUAL CONSUMPTION, WEATHER ADJUSTED									
	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
AVERAGE KWH/CUSTOMER	12466	14990	13388	11714	8624	11022	7201	14491	9066
AVE. SPACE HEAT	4772	6718	6000	5175	5877	3000	3632	8000	5167
ELECTRIC SH SAT%	48%	54%	57%	42%	19%	53%	14%	49%	25%
CD MODEL SH EST.	4592	6237	4794	5227	6123	4209	5256	5548	
	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
BASE LOAD STUDY	5180	6718	?	8672	8023	3321	8438		
ELECTRIC SH	6247	8348	?	9593	8651	6391			
SH WITH WOOD	4070	3553	?	8219	7586	2185			
WOOD ADJUSTMENT %	34.8%	57.4%	57.4%	14.3%	12.3%	65.8%	-11.0%	18.0%	
CDM TOTAL KWH	13194	15432	13545	12857	9963	13167	7226	11804	8241
SFD	13932	16244	14135	13164	10593	14163	7827	13565	9256
MF	9846	11051	11138	12006	8731	9488	5411	5411	5411
MH	13287	16391	13287	12226	8035	12257	7406	7406	7406

Table 4 Adjustment to Engineering Estimate

SPACE HEATING ESTIMATE									
	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
ALL STOCK AVERAGE	8952	9194	9138	8929	9279	8392	8909	9410	8909
SFD AVERAGE	9709	10026	9947	9310	10047	8921	10042	9884	10042
S	5195	5387	5387	6085	5589	5193	5387	5387	5387
M	8243	8556	8556	9627	8867	8240	8556	8556	8556
L	12822	13302	13302	10993	12632	12816	13302	13302	13302
MF	5389	5496	5496	5560	5515	5388	5496	5496	5496
MH	9202	9199	9199	10993	9719	9202	9199	9199	9199
RATIO AVERAGE SH/CDM ESTIMATE									
CALIBRATION ADJUST.	1.0000	1.1962	1.3817	0.9999	1.0000	0.7365	1.0000	0.9005	1.4226
ENGINEERING ESTIMATE > AVERAGE SH									
ADJUSTMENT	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
ALL STOCK AVERAGE	46.7%	26.9%	34.3%	42.0%	36.7%	64.3%	59.2%	15.0%	42.0%

The prototypes are modeled with computer simulation referred to the engineering model. This model overpredicts actual consumption for a variety of reasons. The engineering model does not consider the partial use of wood heat. The simulations are run for one city -- Portland for Zone 1. It is not surprising that the results differ from actual consumption in another town, for example Medford. Consumption is influenced by economic elasticity choices. That is, residents of an unweatherized house may chose to operate the house to a lower degree of comfort than assumed in the engineering models because they cannot afford higher energy bills. Finally, the prototypes may not exactly match actual building stock. For all these reasons, an adjustment is expected.

The downrating adjustment is shown in Table 4. For example, in Oregon space heating is reduced by about 40%. This seems like a large adjustment. However, about half the adjustment can be explained based on what is known about wood heat and heat pump saturations. The remaining adjustment represents climate differences, economic elasticity and prototype mismatch.

There is a policy issue of whether and when to include this factor in societal planning. If the derating factor represents substitution of wood heat, consumers are still receiving the full benefit of space heating. By this argument, the downrating should not be considered when estimating the full benefit to society of the energy savings. However, for this study, the downrating adjustment was applied and savings benefits reduced since it was felt that the adjustment is primarily due to modeling uncertainty. It should be noted that the NPPC derives an adjustment of about 30%. In their modeling, that adjustment is primarily due to economic elasticity.

Table 5 Projected Residential Space Heat

RESIDENTIAL ENDUSE DISAGGREGATION

CURRENT SPACE HEAT CONSUMPTION -- EXISTING STOCK

	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
ALL STOCK AVERAGE	4772	6718	6000	5175	5877	3000	3632	8000	5167
SFD AVERAGE	5323	7533	6250	5373	6377	3110	2755	9408	3919
S	3712	5618	4060	4371	5496	1935	1638	5675	2330
M	4415	5961	5579	4495	5128	2643	2327	8064	3310
L	6766	9760	7863	6823	7644	4759	3620	12545	5150
MF	2795	3731	4401	3734	3819	2246	5442	2354	7742
MH S	4194	5944	6603	5869	5677	3329	7406	4719	10536

WITH DECREASING TREND IN WOOD USAGE

YEAR 2011 SPACE HEAT CONSUMPTION – EXISTING STOCK

	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
ALL STOCK AVERAGE	5449	7529	7722	5564	6159	4697	3632	8568	5436
SFD AVERAGE	6172	8555	8369	5822	6717	5261	2755	10102	4265
S	4092	6066	5112	4602	5620	3148	1638	6053	2450
M	5176	6944	7373	4977	5461	4731	2327	8665	3632
L	7883	11059	10767	7374	8072	7711	3620	13478	5600
MF	2880	3747	4559	3825	3863	2423	5442	2408	7786
MH S	4659	6578	8083	6294	5940	4419	7406	5000	10785

Since part of the adjustment may be due to the use of wood heat and since wood heat is expected to decline, projected space heating should show a slight increase for existing buildings. A projection including some decrease in wood heat is shown in Table 5.

Application of this adjustment factor is particularly problematic when applied to new MCS construction. The Council found good agreement between their engineering estimates and econometric estimates for new construction. Thus, they took no correction for "amenities". For PP&L, the adjustment is thought to represent a variety of climatic and fuel use factors. Thus, half the adjustment factor (after removal of heat pump usage) was applied. This results in a lower estimate for MCS savings, by about 12%, when compared to the Council. The basecase for Utah was taken at a low level representing current practice. Utah has adopted an energy code which comes close to MCS. As enforcement of the new code improves, the Utah basecase will need to be upgraded to represent more efficient buildings. Estimates for new residential space heating are shown in Table 6.

2.5. Takeback Adjustment

The modeling assumes that homes will continue to be operated under the same conditions (Standard Operation Conditions) regarding thermostat setting, room

Table 6 New Residential Space Heat Estimates

ENGINEERING MODEL NEW STOCK, 85% MCS IN NW							NO MCS IN UT, WY		
	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
ALL STOCK AVERAGE	6468	10179	10146	11838	17697	6105	17708	10671	19611
SFD AVERAGE	6866	10947	10901	12676	20571	6465	20738	10862	24190
S	5184	8267	8267	9838	14610	5184	14610	8267	17168
M	5992	10071	10071	11699	20741	5992	20741	10071	24036
L	8308	12864	12864	15349	22727	8308	22727	12864	26654
MF	3030	4931	4931	5884	5129	3030	5129	4931	6116
MH S	5562	9069	9069	10477	13062	5562	13062	9069	13392
L	10020	15429	15429	18241	20982	10020	20982	15429	24647

					SAME ADJUSTMENT FACTOR IN UT, WY				
NEW CONSTRUCTION	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
ADJUSTMENT FACTOR	23.3%	13.5%	17.2%	21.0%	36.7%	32.1%	59.2%	7.5%	42.0%
SFD	22.6%	12.4%	18.6%	21.1%	36.5%	32.6%	72.6%	2.4%	61.0%
S	14.3%	-2.1%	12.3%	14.1%	1.7%	31.4%	69.6%	-2.7%	56.7%
M	23.2%	15.2%	17.4%	26.7%	42.2%	34.0%	72.8%	2.9%	61.3%
L	23.6%	13.3%	20.4%	19.0%	39.5%	31.4%	72.8%	2.8%	61.3%
MF	24.1%	16.1%	10.0%	16.4%	30.7%	29.2%	1.0%	28.6%	-40.9%
MH	27.2%	17.7%	14.1%	23.3%	41.6%	31.9%	19.5%	24.4%	-14.5%
	27.2%	17.7%	14.1%	23.3%	41.6%	31.9%	19.5%	24.4%	-14.5%

closure, fuel choice, etc. This clearly not the case with real inhabitants. Actual savings are less than the engineering estimates due to a variety of consumer "amenity takeback" choices. It is as if the consumers choose to take some savings in the form of increased comfort rather than increased savings. The planner has a choice of treatment for takeback.

(1). One can downrate the savings to agree with monitored results. This ignores the economic value of the increase in amenity and makes the conservation appear more expensive.

(2). One can use the engineering estimates of savings without applying downrating. The increase or rebound in usage would be treated as an increase in the demand forecast. This method does not penalize conservation for customer's usage. However, it may fail to reflect uncertainty and modeling error in the engineering estimates.

(3). One can develop an econometric model to estimate rebound in usage as a function of bill reductions, that is, apply price elasticity. This assumes that one knows price elasticity, which is often not the case.

In our study, we chose option (2) in calculating supply curves based on Total resource Cost (TRC). However, provision for a downrating factor has been included in the model. The downrating has been included in estimates of the utility's programmatic cost.

2.6. Solar Access

Solar access is an important low-cost resource which is often overlooked in utility planning. The methodology for evaluation is based on that developed by ODOE for the Metropolitan Solar Access Study in the Portland Area. The prototype homes were evaluated for space heating energy requirement using the WATTSUN computer program. The critical parameter is alignment, that is, orientation of the house along an east-west axis so that a long side faces south. Scenarios rely on actual survey data from Portland to specify current practice for alignment, shading and window placement. The basecase scenario assumes that homes are constructed 55% in north-south alignment with 40% shade and 45% in east-west alignment with 22% shade. Window areas are distributed for NS houses as 10% north and south, 40% east and west. For homes with EW alignment, window areas are 10% east and west, 30% north and 50% south. The solar orientation scenario assumes that 80% of the homes are aligned east-west with 10% shade and 20% aligned north-south with 30% shade. The solar design scenario assumes that for the oriented homes 15% of the window area is relocated from the north side to the south side. These are listed as two separate measures for new single family construction. There may be additional benefits to solar access, including infill benefits to existing housing and encouragement of solar design and water heating. These benefits are more difficult to quantify and were not assessed.

2.7. Energy Conservation Measures (ECM's)

The delta UA values and cost were originally taken from the Council's spreadsheets. Cost data for some measures were updated based on results from PacifiCorp's multi-family weatherization program as documented by Portland Energy Conservation, Inc. It should be noted that the delta UA values are not based on strict engineering calculations. The Council used empirical values developed by Bonneville. They are supposed to represent actual values achieved in the field, taking into account voids in the insulation and other installer errors. Thus, the values are not linear in terms of R values. Some of the incremental measures required calculating the effective change in U value and interpolating between the points the Council used.

A few ECMs were computed for this study. The cost and delta UA for re-roofing an existing mobile home came from interviews with CAP weatherization teams. This measure appears to be too expensive on an energy basis but might be considered if a new roof was needed anyway. The setback thermostat was another case of a calculated measure. In this case, there were some estimates from Hood River for the annual energy savings. This number needed to be divided by the regression slope (fuel factor corrected) to determine the equivalent delta UA. This value is used in the spreadsheet even though the measure is not, strictly speaking, a measure that affect the envelope UA.

2.8. Residential Spreadsheets

Examples of the residential spreadsheets follow for Oregon, Washington Montana and Utah as representative states. Figure 2 shows an estimate of potential savings relative to existing stock space heat consumption. Figure 3 shows the same information by state. Figure 4 shows an estimate of the potential savings beyond code for new construction. Figure 5 summarizes the same information by state.

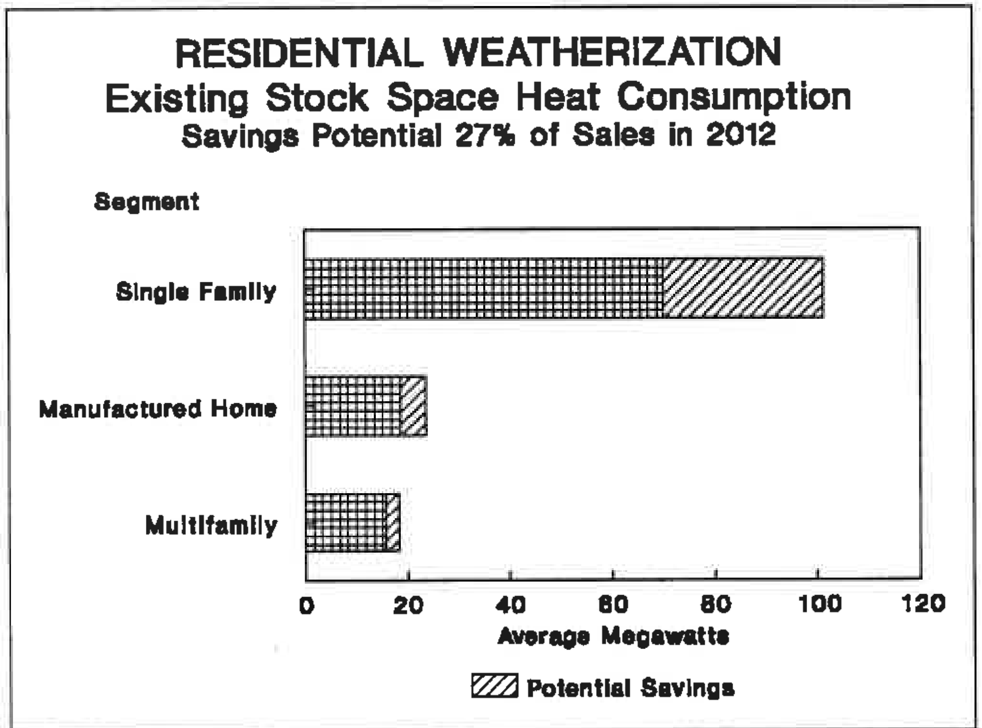


Figure 2 Existing Residential Savings

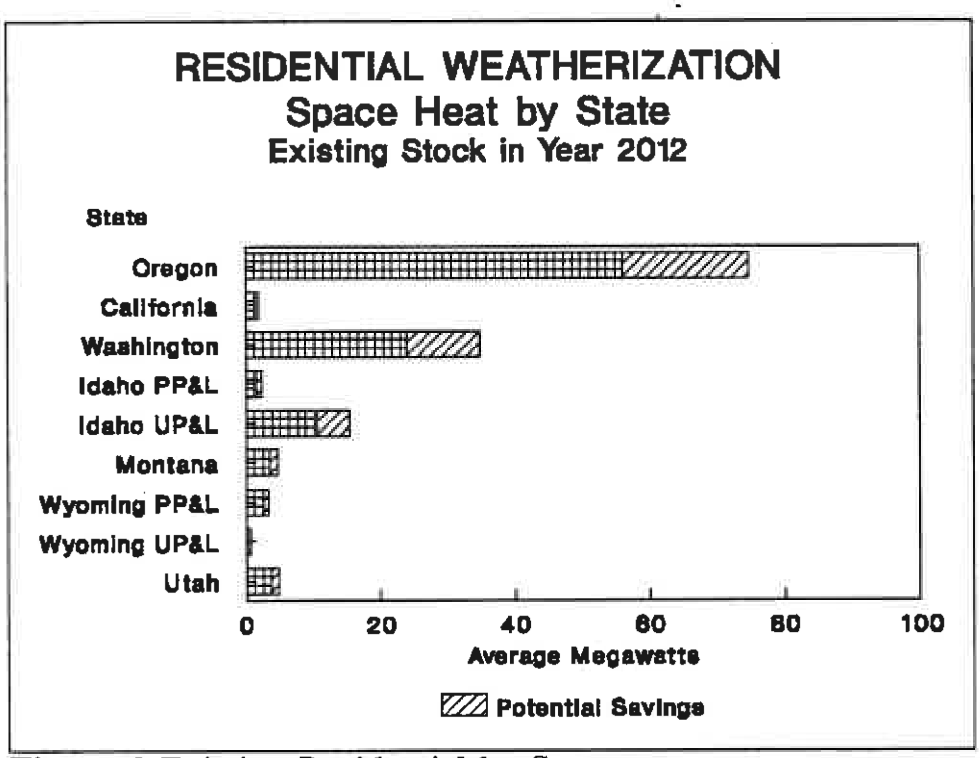


Figure 3 Existing Residential by State

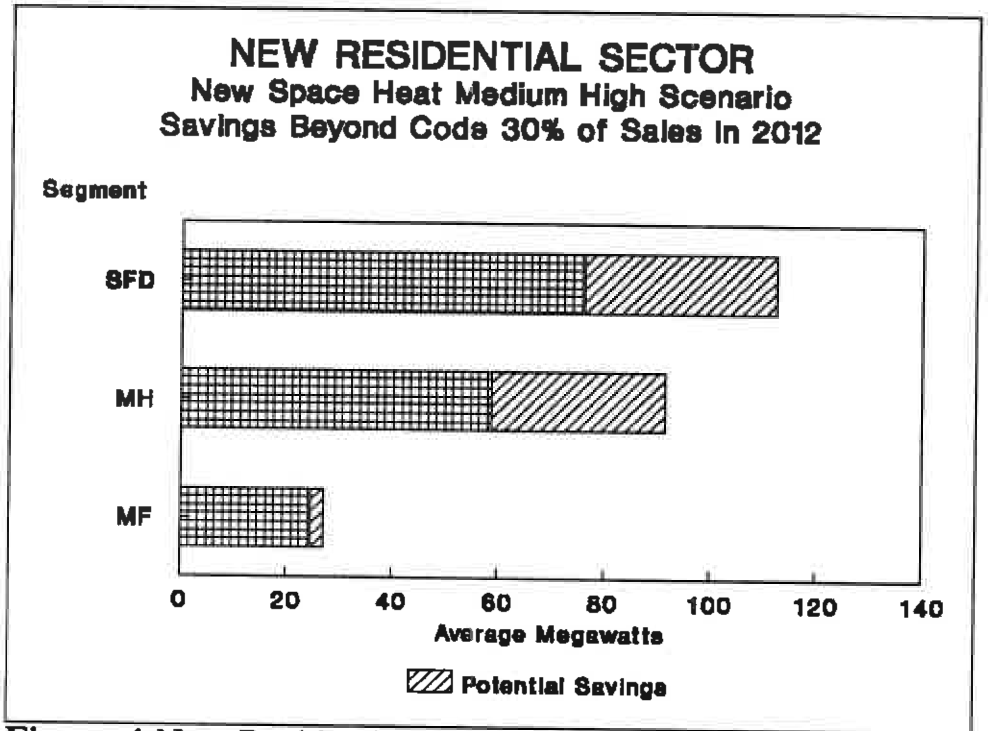


Figure 4 New Residential Savings Potential

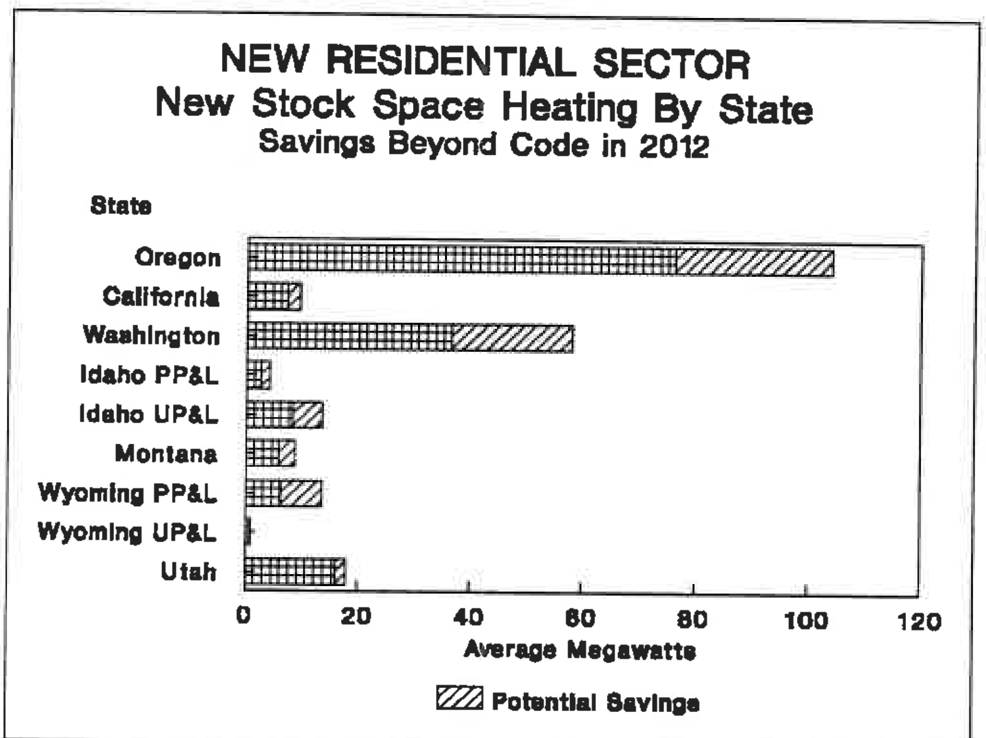


Figure 5 New Residential Savings by State

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

1204 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

57% FUEL FACTOR

30% TAKE-BACK FACTOR

-5841.02 ENERGY USE CONVERSION CONSTANT (KWH/YR)

51.91071 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	850
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	389.00	---	---	---	---	---	6243	---	---	0.000	0.000
WALLS R0>R11	372.80	85.25	518.40	50	19%	100%	5987	256	0.048	18.602	0.035
WALLS R3>R11	369.56	32.40	518.40	50	10%	100%	5936	51	0.048	48.945	0.007
F1 FLOOR R0>R19	345.08	76.50	408.00	50	32%	100%	5549	387	0.048	16.315	0.053
F2 FLOOR R11>R19	343.81	14.11	408.00	50	9%	100%	5529	20	0.048	88.455	0.003
C1 CEIL R0>38	341.72	209.10	586.50	50	1%	100%	5496	33	0.048	8.580	0.005
C3 CEIL R15>R38	340.30	35.60	501.50	50	4%	100%	5473	23	0.048	43.093	0.003
C3 CEIL R20>38	339.77	13.09	467.50	50	4%	100%	5465	8	0.048	109.252	0.001
C4 CEIL R37>38	339.76	1.36	357.00	50	1%	100%	5465	0	0.048	803.002	0.000
C5 CEIL R0>R49	337.57	219.05	739.50	50	1%	100%	5430	35	0.048	10.327	0.005
C6 CEIL R15>R49	325.71	45.60	654.50	50	26%	100%	5243	187	0.048	43.907	0.026
C7 CEIL R20>R49	319.72	23.04	620.50	50	26%	100%	5148	95	0.048	82.385	0.013
C8 CEIL R37>49	318.71	11.31	501.50	50	9%	100%	5132	16	0.048	135.643	0.002
C3 CEIL R38>49	315.92	9.95	399.50	50	28%	100%	5088	44	0.048	122.823	0.006
W1 WIND SG>STORM	295.05	56.40	658.00	30	37%	100%	4758	330	0.059	43.854	0.045
W2 WIND PART>STRM	289.47	31.00	362.00	30	18%	100%	4670	88	0.059	43.895	0.012
W3 WIND DG>CLASS 33	275.94	30.08	1498.00	30	45%	100%	4456	214	0.059	187.198	0.029
W4 WIND SG>CLASS 33 AFT W1	261.50	30.08	840.00	30	48%	100%	4228	228	0.059	104.971	0.031
ACH .6>.5	249.26	12.24	120.00	10	100%	100%	4034	193	0.125	77.326	0.027
DOOR INSUL	239.18	11.20	300.00	30	90%	100%	3875	159	0.059	100.686	0.022
HEAT PUMP	217.46	28.96	2075.00	15	75%	100%	3532	343	0.091	414.089	0.047
CLOCK THERMOSTAT	205.73	15.63	147.00	15	75%	100%	3346	185	0.091	54.350	0.025

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	1350
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

1625	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
72%	FUEL FACTOR
30%	TAKE-BACK FACTOR
-7181.25	ENERGY USE CONVERSION CONSTANT (KWH/YR)
52.8951	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	563.00	---	---	---	---	---	6418	---	---	0.000	0.000
WALLS R0>R11	545.78	132.44	586.38	50	13%	100%	6237	181	0.048	20.359	0.034
WALLS R6>11	542.75	12.13	545.94	50	25%	100%	6205	32	0.048	206.959	0.006
F1 FLOOR R0>R19	492.33	112.05	648.00	50	45%	100%	5675	530	0.048	26.593	0.098
F2 FLOOR R11>19	487.83	23.65	594.00	50	19%	100%	5628	47	0.048	115.493	0.009
C1 CEIL R8>38	480.72	64.67	931.50	50	11%	100%	5553	75	0.048	66.234	0.014
C2 CEIL R13>38	470.29	47.39	864.00	50	22%	100%	5443	110	0.048	83.835	0.020
C3 CEIL R21>38	469.32	19.58	742.50	50	5%	100%	5433	10	0.048	174.375	0.002
C4 CEIL R37>38	469.25	2.16	607.50	50	3%	100%	5432	1	0.048	1293.280	0.000
C5 CEIL R8>49	462.70	72.77	1174.50	50	9%	100%	5363	69	0.048	74.217	0.013
C6 CEIL R13>49	452.16	55.49	1107.00	50	19%	100%	5252	111	0.048	91.735	0.021
C7 CEIL R21>49	451.05	27.67	985.50	50	4%	100%	5241	12	0.048	163.775	0.002
C8 CEIL R37>49	450.74	10.24	702.00	50	3%	100%	5238	3	0.048	315.237	0.001
C3 CEIL R38>49	448.40	8.10	634.50	50	29%	100%	5213	25	0.048	360.202	0.005
W1 WIND SG>STORM	437.55	83.44	1043.00	30	13%	100%	5099	114	0.059	70.630	0.021
W2 WIND PART>STRM	418.89	60.20	752.50	30	31%	100%	4903	196	0.059	70.630	0.036
W3 WIND DG>CLASS 33	390.76	47.68	2375.00	30	59%	100%	4607	296	0.059	281.454	0.055
W4 WIND SG>CLASS 33 AFT W1	372.64	47.68	1332.00	30	38%	100%	4416	191	0.059	157.851	0.035
ACH .6>.5	353.20	19.44	120.00	10	100%	100%	4212	204	0.125	73.186	0.038
DOOR INSUL	343.12	11.20	300.00	30	90%	100%	4106	106	0.059	151.350	0.020
HEAT PUMP	288.05	73.42	2075.00	15	75%	100%	3527	579	0.091	245.525	0.107
CLOCK THERMOSTAT	270.42	23.50	147.00	15	75%	100%	3341	185	0.091	54.350	0.034

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

1299 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

69% FUEL FACTOR

30% TAKE-BACK FACTOR

-11512.29 ENERGY USE CONVERSION CONSTANT (KWH/YR)

51.7407 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	2100
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	835.00	---	---	---	---	---	9761	—	---	0.000	0.000
WALLS R0>R11	785.38	198.47	878.70	50	25%	100%	9207	553	0.048	19.191	0.082
WALLS R6>11	783.02	18.18	802.95	50	13%	100%	9181	26	0.048	191.446	0.004
C1 CEIL R17>38	781.59	20.44	483.00	50	7%	100%	9165	16	0.048	102.428	0.002
C2 CEIL R19>38	781.15	14.70	483.00	50	3%	100%	9160	5	0.048	142.423	0.001
C3 CEIL R17>49	777.14	28.64	609.00	50	14%	100%	9115	45	0.048	92.171	0.007
C4 CEIL R19>49	775.53	22.90	574.00	50	7%	100%	9098	18	0.048	108.649	0.003
C5 CEIL R35>49	773.89	8.20	427.00	50	20%	100%	9079	18	0.048	225.717	0.003
W1 WIND SG>STORM	711.65	163.80	2205.00	50	38%	100%	8385	694	0.048	58.351	0.103
W2 WIND PART>STRM	673.70	97.30	1309.81	30	39%	100%	7962	423	0.059	71.701	0.063
W3 WIND DG>CLASS 33	649.51	100.80	5021.00	30	24%	100%	7692	270	0.059	265.314	0.040
W4 WIND SG>CLASS33 AFT W1	572.90	100.80	2816.00	30	76%	100%	6837	855	0.059	148.800	0.127
ACH .6>.5	540.14	32.76	120.00	10	100%	100%	6472	365	0.125	40.938	0.054
DOOR INSUL	530.06	11.20	150.00	30	90%	100%	6359	112	0.059	71.335	0.017
HEAT PUMP	439.00	121.42	2075.00	15	75%	100%	5343	1016	0.091	139.956	0.151
CLOCK THERMOSTAT	422.38	22.15	147.00	15	75%	100%	5158	185	0.091	54.350	0.027
HEAT PUMP	366.24	112.28	2800.00	15	50%	100%	4532	626	0.091	204.233	0.093

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

1346	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
28%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-6042.09	ENERGY USE CONVERSION CONSTANT (KWH/YR)
49.27813	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	471.00	---	---	---	---	---	12327	---	---	0.000	0.000
SUPER G.S. ENVELOPE	385.00	86.00	1695.00	70	100%	100%	9284	3043	0.045	24.908	0.468
SOLAR ORIENT.	358.08	26.92	26.00	70	100%	100%	8331	952	0.045	1.221	0.146
SOLAR WINDOWS	355.56	2.52	20.00	70	100%	100%	8242	89	0.045	10.030	0.014
SGC WINDOW & DOOR	266.56	89.00	1245.00	30	100%	100%	5093	3149	0.059	23.492	0.484
ROOF R38>49 ADV	255.56	11.00	392.00	70	100%	100%	4704	389	0.045	45.036	0.060
WALL R22>R26 ADV	231.56	24.00	802.00	70	100%	100%	3855	849	0.045	42.231	0.130
WALL R26 A>R40 BDW	214.56	17.00	1590.00	70	100%	100%	3253	601	0.045	118.200	0.092
CLASS 33 WINDOW AFTER SGC	197.06	17.50	406.00	30	100%	100%	2634	619	0.059	38.960	0.095
FLOOR R38	192.23	4.83	713.00	70	100%	100%	2463	171	0.045	186.558	0.026

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

735 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

36% FUEL FACTOR

0% TAKE-BACK FACTOR

-7450.96 ENERGY USE CONVERSION CONSTANT (KWH/YR)

50.56832 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1848
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	628.00	---		---	---	---	15604	---	---	0.000	0.000
SUPER G.S. ENVELOPE	532.00	96.00	2266.00	70	100%	100%	12488	3117	0.045	32.511	0.261
SOLAR ORIENT.	505.28	26.72	26.00	70	100%	100%	11620	867	0.045	1.340	0.073
SOLAR WINDOWS	490.92	14.36	20.00	70	100%	100%	11154	466	0.045	1.918	0.039
SGC WINDOW	380.92	110.00	1124.00	30	100%	100%	7583	3571	0.059	18.701	0.300
ROOF R38>49 ADV	367.92	13.00	441.00	70	100%	100%	7161	422	0.045	46.723	0.035
WALL R22>R26 ADV	329.92	38.00	1287.00	70	100%	100%	5927	1234	0.045	46.648	0.104
WALL R26 A>R40 BDW	302.92	27.00	2546.00	70	100%	100%	5051	877	0.045	129.877	0.074
CLASS 33 WINDOW AFTER SGC	278.92	24.00	557.00	30	100%	100%	4272	779	0.059	42.476	0.065
FLOOR R38	0.00	2.72	386.00	0	0%	0%	0	0	0.000	0.000	0.000

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	2352
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

1890	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
25%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-8861.38	ENERGY USE CONVERSION CONSTANT (KWH/YR)
49.25839	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	721.00	---	---	---	---	---	20097	---	---	0.000	0.000
SUPER G.S. ENVELOPE	597.00	124.00	2985.00	70	100%	100%	15492	4605	0.045	28.981	0.994
SOLAR ORIENT.	559.00	38.00	26.00	70	100%	100%	14080	1411	0.045	0.824	0.305
SOLAR WINDOWS	539.05	19.95	20.00	70	100%	100%	13339	741	0.045	1.207	0.160
SGC WINDOW	393.05	146.00	1538.00	30	100%	100%	7917	5423	0.059	16.852	1.170
ROOF R38>49 ADV	379.05	14.00	472.00	70	100%	100%	7397	520	0.045	40.589	0.112
WALL R22>R26 ADV	349.05	30.00	1028.00	70	100%	100%	6283	1114	0.045	41.254	0.240
WALL R26 A>R40 BDW	328.05	21.00	2036.00	70	100%	100%	5503	780	0.045	116.723	0.168
CLASS 33 WINDOW AFTER SGC	302.25	25.80	598.00	30	100%	100%	4544	958	0.059	37.080	0.207
BASEMENT	270.37	31.88	1098.00	70	100%	100%	3360	1184	0.045	41.465	0.255

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

24955 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

42% FUEL FACTOR

30% TAKE-BACK FACTOR

-5090.3363 ENERGY USE CONVERSION CONSTANT (KWH/YR)

34.71344773 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	850
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	388.00	---	---	---	---	---	4893	---	---	0.000	0.000
WALLS R0>R11	371.80	85.25	518.40	50	19%	100%	4663	230	0.048	20.720	0.655
WALLS R3>R11	368.56	32.40	518.40	50	10%	100%	4617	46	0.048	54.518	0.131
F1 FLOOR R0>R19	344.08	76.50	408.00	50	32%	100%	4270	347	0.048	18.173	0.990
F2 FLOOR R11>R19	342.81	14.11	408.00	50	9%	100%	4252	18	0.048	98.527	0.051
C1 CEIL R0>38	340.72	209.10	586.50	50	1%	100%	4222	30	0.048	9.557	0.085
C3 CEIL R15>R38	339.30	35.60	501.50	50	4%	100%	4202	20	0.048	48.000	0.058
C3 CEIL R20>38	338.77	13.09	467.50	50	4%	100%	4194	7	0.048	121.693	0.021
C4 CEIL R37>38	338.76	1.36	357.00	50	1%	100%	4194	0	0.048	894.442	0.001
C5 CEIL R0>R49	336.57	219.05	739.50	50	1%	100%	4163	31	0.048	11.503	0.089
C6 CEIL R15>R49	324.71	45.60	654.50	50	26%	100%	3995	168	0.048	48.907	0.479
C7 CEIL R20>R49	318.72	23.04	620.50	50	26%	100%	3910	85	0.048	91.766	0.242
C8 CEIL R37>49	317.71	11.31	501.50	50	9%	100%	3895	14	0.048	151.089	0.041
C3 CEIL R38>49	314.92	9.95	399.50	50	28%	100%	3856	40	0.048	136.810	0.113
W1 WIND SG>STORM	294.05	56.40	658.00	30	37%	100%	3560	296	0.059	48.848	0.844
W2 WIND PART>STRM	288.47	31.00	362.00	30	18%	100%	3481	79	0.059	48.893	0.226
W3 WIND DG > CLASS 33	274.03	30.08	1498.00	30	48%	100%	3276	205	0.059	208.515	0.584
W4 WIND SG > CLASS 33 AFTE[illegible]	30.08	840.00	30	45%	100%	3084	192	0.059	116.924	0.547	
ACH .6>.5	248.26	12.24	120.00	10	100%	100%	2910	174	0.125	86.132	0.495
DOOR INSUL	238.18	11.20	300.00	30	90%	100%	2767	143	0.059	112.152	0.408
HEAT PUMP	213.98	32.26	2075.00	15	75%	100%	2424	343	0.091	414.089	0.978
CLOCK THERMOSTAT	200.92	17.41	147.00	15	75%	100%	2238	185	0.091	54.350	0.528

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

35326 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

60% FUEL FACTOR

30% TAKE-BACK FACTOR

-6379.76643 ENERGY USE CONVERSION CONSTANT (KWH/YR)

36.01357063 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	1350
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	528.00	---	—	---	---	---	5079	---	---	0.000	0.000
WALLS R0>R11	510.78	132.44	586.38	50	13%	100%	4905	174	0.048	21.125	0.704
WALLS R6>11	507.75	12.13	545.94	50	25%	100%	4874	31	0.048	214.746	0.124
F1 FLOOR R0>R19	457.33	112.05	648.00	50	45%	100%	4363	511	0.048	27.593	2.061
F2 FLOOR R11>19	452.83	23.65	594.00	50	19%	100%	4318	46	0.048	119.839	0.184
C1 CEIL R8>38	445.72	64.67	931.50	50	11%	100%	4246	72	0.048	68.726	0.291
C2 CEIL R13>38	435.29	47.39	864.00	50	22%	100%	4140	106	0.048	86.900	0.426
C3 CEIL R21>38	434.32	19.58	742.50	50	5%	100%	4130	10	0.048	180.936	0.040
C4 CEIL R37>38	434.25	2.16	607.50	50	3%	100%	4129	1	0.048	1341.943	0.003
C5 CEIL R8>49	427.70	72.77	1174.50	50	9%	100%	4063	66	0.048	77.009	0.268
C6 CEIL R13>49	417.16	55.49	1107.00	50	19%	100%	3956	107	0.048	95.186	0.431
C7 CEIL R21>49	416.05	27.67	985.50	50	4%	100%	3945	11	0.048	169.937	0.045
C8 CEIL R37>49	415.74	10.24	702.00	50	3%	100%	3942	3	0.048	327.099	0.013
C3 CEIL R38>49	413.40	8.10	634.50	50	29%	100%	3918	24	0.048	373.756	0.096
W1 WIND SG>STORM	402.55	83.44	1043.00	30	13%	100%	3808	110	0.059	73.288	0.443
W2 WIND PART>STRM	383.89	60.20	752.50	30	31%	100%	3619	189	0.059	73.288	0.763
W3 WIND DG>CLASS 33	355.76	47.68	2375.00	30	59%	100%	3334	285	0.059	292.044	1.150
W4 WIND SG>CLASS 33 AFTER W1	337.64	47.68	1332.00	30	38%	100%	3150	184	0.059	163.791	0.740
ACH .6>.5	318.20	19.44	120.00	10	100%	100%	2953	197	0.125	75.939	0.794
DOOR INSUL	308.12	11.20	300.00	30	90%	100%	2851	102	0.059	157.045	0.412
HEAT PUMP	250.98	76.19	2075.00	15	75%	100%	2272	579	0.091	245.525	2.335
CLOCK THERMOSTAT	232.69	24.38	147.00	15	75%	100%	2087	185	0.091	54.350	0.747

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	2100
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

24029	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
51%	FUEL FACTOR
30%	TAKE-BACK FACTOR
-9499.81675	ENERGY USE CONVERSION CONSTANT (KWH/YR)
34.54191398	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	811.00	---	---	---	---	---	8998	---	---	0.000	0.000
WALLS R0>R11	761.38	198.47	878.70	50	25%	100%	8415	583	0.048	18.218	1.599
WALLS R6>11	759.02	18.18	802.95	50	13%	100%	8387	28	0.048	181.738	0.076
C1 CEIL R17>38	757.59	20.44	483.00	50	7%	100%	8370	17	0.048	97.234	0.046
C2 CEIL R19>38	757.15	14.70	483.00	50	3%	100%	8365	5	0.048	135.201	0.014
C3 CEIL R17>49	753.14	28.64	609.00	50	14%	100%	8318	47	0.048	87.497	0.129
C4 CEIL R19>49	751.53	22.90	574.00	50	7%	100%	8299	19	0.048	103.140	0.052
C5 CEIL R35>49	749.89	8.20	427.00	50	20%	100%	8280	19	0.048	214.272	0.053
W1 WIND SG>STORM	687.65	163.80	2205.00	50	38%	100%	7548	731	0.048	55.392	2.006
W2 WIND PART>STRM	649.70	97.30	1309.81	30	39%	100%	7102	446	0.059	68.065	1.223
W3 WIND DG>CLASS 33	625.51	100.80	5021.00	30	24%	100%	6818	284	0.059	251.861	0.780
W4 WIND SG>CLASS 33 AFTER W1	548.90	100.80	2816.00	30	76%	100%	5918	900	0.059	141.255	2.469
ACH .6>.5	516.14	32.76	120.00	10	100%	100%	5533	385	0.125	38.862	1.056
DOOR INSUL	506.06	11.20	150.00	30	90%	100%	5414	118	0.059	67.718	0.325
HEAT PUMP	419.61	115.27	3169.58	15	75%	100%	4398	1016	0.091	213.784	2.787
CLOCK THERMOSTAT	403.84	21.03	147.00	15	75%	100%	4213	185	0.091	54.350	0.508
HEAT PUMP AFTER A/C	401.54	115.27	1594.58	15	2%	100%	4186	27	0.091	107.552	0.074

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

14503 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

25% FUEL FACTOR

0% TAKE-BACK FACTOR

-4391.45 ENERGY USE CONVERSION CONSTANT (KWH/YR)

28.02607 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	471.00	---	---	---	---	---	6598	---	---	0.000	0.000
SUPER G.S. ENVELOPE	385.00	86.00	2041.00	70	100%	100%	4793	1805	0.045	50.553	2.989
ROOF R38>R49 ADV	374.00	11.00	392.00	70	100%	100%	4562	231	0.045	75.910	0.382
WALL R22>R26 ADV	350.00	24.00	802.00	70	100%	100%	4058	504	0.045	71.182	0.834
SOLAR ORIENT.	329.83	20.17	26.00	70	100%	100%	3634	423	0.045	2.746	0.701
SOLAR WINDOWS	329.83	0.00	20.00	70	100%	100%	3634	0	0.045	0.000	0.000
SGS WINDOWS & DOOR	240.83	89.00	899.00	30	100%	100%	1766	1868	0.059	28.592	3.093
WALL R26 A>R40 BDW	223.83	17.00	1590.00	70	100%	100%	1409	357	0.045	199.230	0.591
CLASS 33 WINDOW AFTER SGC	206.33	17.50	406.00	30	100%	100%	1042	367	0.059	65.668	0.608

FOR THE YEAR 2012 — CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

19784	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
25%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-5474.64	ENERGY USE CONVERSION CONSTANT (KWH/YR)
29.2747	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1848
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	628.00	---	---	---	---	---	9631	---	---	0.000	0.000
SUPER G.S. ENVELOPE	532.00	96.00	2266.00	70	100%	100%	7534	2097	0.045	48.329	4.735
ROOF R38>R49 ADV	519.00	13.00	441.00	70	100%	100%	7250	284	0.045	69.457	0.641
WALL R22>R26 ADV	481.00	38.00	1287.00	70	100%	100%	6420	830	0.045	69.345	1.874
SOLAR ORIENT.	459.99	21.01	26.00	70	100%	100%	5962	459	0.045	2.534	1.036
SOLAR WINDOWS	449.92	10.07	20.00	70	100%	100%	5742	220	0.045	4.066	0.497
SGS WINDOWS & DOOR	339.92	110.00	1124.00	30	100%	100%	3339	2402	0.059	27.801	5.425
WALL R26 A>R40 BDW	312.92	27.00	2546.00	70	100%	100%	2750	590	0.045	193.069	1.332
CLASS 33 WINDOW AFTER SGC	288.92	24.00	557.00	30	100%	100%	2226	524	0.059	63.143	1.184

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	2352
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

40087	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
26%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-6515.56	ENERGY USE CONVERSION CONSTANT (KWH/YR)
28.52652	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	721.00	---	---	---	---	---	10441	---	---	0.000	0.000
SUPER G.S. ENVELOPE	627.00	94.00	1926.00	70	100%	100%	8448	1992	0.045	43.226	9.117
ROOF R38>R49 ADV	613.00	14.00	472.00	70	100%	100%	8152	297	0.045	71.126	1.358
WALL R22>R26 ADV	583.00	30.00	1028.00	70	100%	100%	7516	636	0.045	72.291	2.910
SOLAR ORIENT.	546.07	36.93	26.00	70	100%	100%	6733	783	0.045	1.485	3.582
SOLAR WINDOWS	529.66	16.41	20.00	70	100%	100%	6385	348	0.045	2.571	1.592
SGS WINDOW & DOOR	383.66	146.00	1538.00	30	100%	100%	3291	3094	0.059	29.531	14.161
WALL R26 A>R40 BDW	362.66	21.00	2036.00	70	100%	100%	2846	445	0.045	204.536	2.037
CLASS 33 WINDOW	336.86	25.80	598.00	30	100%	100%	2299	547	0.059	64.976	2.502
BASEMENT	304.98	31.88	1098.00	70	100%	100%	1623	676	0.045	72.660	3.092

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	850
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

2879	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
82%	FUEL FACTOR
30%	TAKE-BACK FACTOR
-5321.07714	ENERGY USE CONVERSION CONSTANT (KWH/YR)
45.15344409	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	406.00	---	---	---	---	---	2342	---	---	0.000	0.000
WALLS R0>R11	389.80	85.25	518.40	50	19%	100%	2250	92	0.048	51.682	0.030
WALLS R3>R11	386.56	32.40	518.40	50	10%	100%	2231	18	0.048	135.985	0.006
F1 FLOOR R0>R19	362.08	76.50	408.00	50	32%	100%	2092	139	0.048	45.328	0.046
F2 FLOOR R11>R19	360.81	14.11	408.00	50	9%	100%	2085	7	0.048	245.756	0.002
C1 CEIL R0>38	358.72	209.10	586.50	50	1%	100%	2073	12	0.048	23.839	0.004
C3 CEIL R15>R38	357.30	35.60	501.50	50	4%	100%	2065	8	0.048	119.727	0.003
C3 CEIL R20>38	356.77	13.09	467.50	50	4%	100%	2062	3	0.048	303.537	0.001
C4 CEIL R37>38	356.76	1.36	357.00	50	1%	100%	2062	0	0.048	2231.000	0.000
C5 CEIL R0>R49	354.57	219.05	739.50	50	1%	100%	2049	12	0.048	28.692	0.004
C6 CEIL R15>R49	342.71	45.60	654.50	50	26%	100%	1982	67	0.048	121.987	0.022
C7 CEIL R20>R49	336.72	23.04	620.50	50	26%	100%	1948	34	0.048	228.891	0.011
C8 CEIL R37>49	335.71	11.31	501.50	50	9%	100%	1942	6	0.048	376.859	0.002
C3 CEIL R38>49	332.92	9.95	399.50	50	28%	100%	1926	16	0.048	341.243	0.005
W1 WIND SG>STORM	312.05	56.40	658.00	30	37%	100%	1808	119	0.059	121.842	0.039
W2 WIND PART>STRM	306.47	31.00	362.00	30	18%	100%	1776	32	0.059	121.954	0.010
W3 WIND DG>CLASS 33	292.94	30.08	1498.00	30	45%	100%	1699	77	0.059	520.096	0.025
W4 WIND SG>CLASS33 AFT W1	278.50	30.08	840.00	30	48%	100%	1617	82	0.059	291.643	0.027
ACH .6>.5	266.26	12.24	120.00	10	100%	100%	1547	70	0.125	214.838	0.023
DOOR INSUL	256.18	11.20	300.00	30	90%	100%	1490	57	0.059	279.739	0.019
HEAT PUMP	195.83	80.47	2075.00	15	75%	100%	1146	343	0.091	414.089	0.113
CLOCK THERMOSTAT	163.25	43.43	147.00	15	75%	100%	961	185	0.091	54.350	0.061

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	1350
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

3290 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

76% FUEL FACTOR

30% TAKE-BACK FACTOR

-6517.59 ENERGY USE CONVERSION CONSTANT (KWH/YR)

45.89082 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	587.00	---	---	—	---	---	4880	---	---	0.000	0.000
WALLS R0>R11	569.78	132.44	586.38	50	13%	100%	4748	132	0.048	27.885	0.050
WALLS R6>11	566.75	12.13	545.94	50	25%	100%	4725	23	0.048	283.462	0.009
F1 FLOOR R0>R19	516.33	112.05	648.00	50	45%	100%	4338	387	0.048	36.423	0.145
F2 FLOOR R11>19	511.83	23.65	594.00	50	19%	100%	4303	34	0.048	158.185	0.013
C1 CEIL R8>38	504.72	64.67	931.50	50	11%	100%	4249	55	0.048	90.717	0.021
C2 CEIL R13>38	494.29	47.39	864.00	50	22%	100%	4169	80	0.048	114.825	0.030
C3 CEIL R21>38	493.32	19.58	742.50	50	5%	100%	4161	8	0.048	238.833	0.003
C4 CEIL R37>38	493.25	2.16	607.50	50	3%	100%	4161	0	0.048	1771.342	0.000
C5 CEIL R8>49	486.70	72.77	1174.50	50	9%	100%	4110	50	0.048	101.651	0.019
C6 CEIL R13>49	476.16	55.49	1107.00	50	19%	100%	4029	81	0.048	125.644	0.030
C7 CEIL R21>49	475.05	27.67	985.50	50	4%	100%	4021	8	0.048	224.315	0.003
C8 CEIL R37>49	474.74	10.24	702.00	50	3%	100%	4019	2	0.048	431.765	0.001
C3 CEIL R38>49	472.40	8.10	634.50	50	29%	100%	4001	18	0.048	493.352	0.007
W1 WIND SG>STORM	461.55	83.44	1043.00	30	13%	100%	3917	83	0.059	96.739	0.031
W2 WIND PART>STRM	442.89	60.20	752.50	30	31%	100%	3774	143	0.059	96.739	0.054
W3 WIND DG>CLASS 33	414.76	47.68	2375.00	30	59%	100%	3558	216	0.059	385.493	0.081
W4 WIND SG>CLASS33 AFT W1	396.64	47.68	1332.00	30	38%	100%	3419	139	0.059	216.201	0.052
ACH .6>.5	377.20	19.44	120.00	10	100%	100%	3270	149	0.125	100.239	0.056
DOOR INSUL	367.12	11.20	300.00	30	90%	100%	3192	77	0.059	207.297	0.029
HEAT PUMP	291.69	100.57	2075.00	15	75%	100%	2613	579	0.091	245.525	0.217
CLOCK THERMOSTAT	267.55	32.18	147.00	15	75%	100%	2428	185	0.091	54.350	0.070

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

2056	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
81%	FUEL FACTOR
30%	TAKE-BACK FACTOR
-10453.8	ENERGY USE CONVERSION CONSTANT (KWH/YR)
44.86472	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	2100
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	852.00	---	---	---	---	---	5165	---	---	0.000	0.000
WALLS R0>R11	802.38	198.47	878.70	50	25%	100%	4876	290	0.048	36.649	0.068
WALLS R6>11	800.02	18.18	802.95	50	13%	100%	4862	14	0.048	365.604	0.003
C1 CEIL R17>38	798.59	20.44	483.00	50	7%	100%	4853	8	0.048	195.606	0.002
C2 CEIL R19>38	798.15	14.70	483.00	50	3%	100%	4851	3	0.048	271.985	0.001
C3 CEIL R17>49	794.14	28.64	609.00	50	14%	100%	4827	23	0.048	176.019	0.005
C4 CEIL R19>49	792.53	22.90	574.00	50	7%	100%	4818	9	0.048	207.488	0.002
C5 CEIL R35>49	790.89	8.20	427.00	50	20%	100%	4808	10	0.048	431.052	0.002
W1 WIND SG>STORM	728.65	163.80	2205.00	50	38%	100%	4445	364	0.048	111.432	0.085
W2 WIND PART>STRM	690.70	97.30	1309.81	30	39%	100%	4223	222	0.059	136.928	0.052
W3 WIND DG>CLASS 33	666.51	100.80	5021.00	30	24%	100%	4082	141	0.059	506.670	0.033
W4 WIND SG>CLASS33 AFT W1	589.90	100.80	2816.00	30	76%	100%	3634	447	0.059	284.163	0.105
ACH .6>.5	557.14	32.76	120.00	10	100%	100%	3443	191	0.125	78.180	0.045
DOOR INSUL	547.06	11.20	150.00	30	90%	100%	3384	59	0.059	136.229	0.014
HEAT PUMP	373.15	231.88	2075.00	15	75%	100%	2368	1016	0.091	139.956	0.238
CLOCK THERMOSTAT	341.43	42.30	147.00	15	75%	100%	2183	185	0.091	54.350	0.043
HEAT PUMP	285.29	112.28	2800.00	15	50%	100%	1855	328	0.091	390.024	0.077

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

6052	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
82%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-5473.05	ENERGY USE CONVERSION CONSTANT (KWH/YR)
42.63857	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	471.00	---	---	---	---	---	2630	---	---	0.000	0.000
SUPER G.S. ENVELOPE	385.00	86.00	1695.00	70	100%	100%	1970	660	0.045	114.827	0.456
ROOF R38>R49 ADV	374.00	11.00	392.00	70	100%	100%	1885	84	0.045	207.619	0.058
WALL R22>R26 ADV	350.00	24.00	802.00	70	100%	100%	1701	184	0.045	194.687	0.127
SOLAR ORIENT.	321.96	28.04	26.00	70	100%	100%	1486	215	0.045	5.402	0.149
SOLAR WINDOWS	317.57	4.39	20.00	70	100%	100%	1452	34	0.045	26.542	0.023
SGC WINDOWS & DOOR	228.57	89.00	1245.00	30	100%	100%	769	683	0.059	108.297	0.472
WALL R26 A>R40 BDW	211.57	17.00	1590.00	70	100%	100%	639	130	0.045	544.907	0.090
CLASS 33 WINDOW AFTER SGC	194.07	17.50	406.00	30	100%	100%	504	134	0.059	179.607	0.093

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1848
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

3026	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
76%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-6733.87	ENERGY USE CONVERSION CONSTANT (KWH/YR)
43.75055	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	628.00	---	---	---	---	---	4957	---	---	0.000	0.000
SUPER G.S. ENVELOPE	532.00	96.00	2056.00	70	100%	100%	3953	1004	0.045	91.584	0.347
ROOF R38>R49 ADV	519.00	13.00	441.00	70	100%	100%	3817	136	0.045	145.065	0.047
WALL R22>R26 ADV	481.00	38.00	1287.00	70	100%	100%	3420	397	0.045	144.832	0.137
SOLAR ORIENT.	452.15	28.85	26.00	70	100%	100%	3118	302	0.045	3.854	0.104
SOLAR WINDOWS	436.32	15.83	20.00	70	100%	100%	2953	166	0.045	5.403	0.057
SGC WINDOWS & DOOR	326.32	110.00	1334.00	30	100%	100%	1803	1150	0.059	68.912	0.397
WALL R26 A>R40 BDW	299.32	27.00	2546.00	70	100%	100%	1520	282	0.045	403.239	0.098
CLASS 33 WINDOW AFTER SGC	275.32	24.00	557.00	30	100%	100%	1269	251	0.059	131.878	0.087

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	2352
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

6052	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
81%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-8256.22	ENERGY USE CONVERSION CONSTANT (KWH/YR)
42.97208	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	721.00	---	---	---	---	---	4227	---	---	0.000	0.000
SUPER G.S. ENVELOPE	627.00	94.00	1574.00	70	100%	100%	3476	751	0.045	93.676	0.519
ROOF R38>R49 ADV	613.00	14.00	472.00	70	100%	100%	3364	112	0.045	188.610	0.077
WALL R22>R26 ADV	583.00	30.00	1028.00	70	100%	100%	3124	240	0.045	191.700	0.166
SOLAR ORIENT.	541.70	41.30	26.00	70	100%	100%	2794	330	0.045	3.522	0.228
SOLAR WINDOWS	518.76	22.94	20.00	70	100%	100%	2611	183	0.045	4.877	0.127
SGC WINDOW	372.76	146.00	1810.00	30	100%	100%	1444	1167	0.059	92.159	0.806
WALL R26 A>R40 BDW	351.76	21.00	2036.00	70	100%	100%	1276	168	0.045	542.386	0.116
CLASS 33 WINDOW AFTER SGC	325.96	25.80	598.00	30	100%	100%	1070	206	0.059	172.303	0.142
BASEMENT	294.08	31.88	1098.00	70	100%	100%	815	255	0.045	192.679	0.176

FOR THE YEAR 2012 — CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

9542 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

38% FUEL FACTOR

30% TAKE-BACK FACTOR

-5321.07714 ENERGY USE CONVERSION CONSTANT (KWH/YR)

45.15344409 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	850
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	406.00	---	---	---	---	---	8028	---	---	0.000	0.000
WALLS R0>R11	389.80	85.25	518.40	50	19%	100%	7712	316	0.048	15.077	0.344
WALLS R3>R11	386.56	32.40	518.40	50	10%	100%	7649	63	0.048	39.671	0.069
F1 FLOOR R0>R19	362.08	76.50	408.00	50	32%	100%	7171	477	0.048	13.224	0.520
F2 FLOOR R11>R19	360.81	14.11	408.00	50	9%	100%	7147	25	0.048	71.695	0.027
C1 CEIL R0>38	358.72	209.10	586.50	50	1%	100%	7106	41	0.048	6.955	0.044
C3 CEIL R15>R38	357.30	35.60	501.50	50	4%	100%	7078	28	0.048	34.928	0.030
C3 CEIL R20>38	356.77	13.09	467.50	50	4%	100%	7068	10	0.048	38.552	0.011
C4 CEIL R37>38	356.76	1.36	357.00	50	1%	100%	7068	0	0.048	650.859	0.000
C5 CEIL R0>R49	354.57	219.05	739.50	50	1%	100%	7025	43	0.048	8.371	0.047
C6 CEIL R15>R49	342.71	45.60	654.50	50	26%	100%	6794	231	0.048	35.588	0.252
C7 CEIL R20>R49	336.72	23.04	620.50	50	26%	100%	6677	117	0.048	66.775	0.127
C8 CEIL R37>49	335.71	11.31	501.50	50	9%	100%	6657	20	0.048	109.943	0.022
C3 CEIL R38>49	332.92	9.95	399.50	50	28%	100%	6603	54	0.048	99.552	0.059
W1 WIND SG>STORM	312.05	56.40	658.00	30	37%	100%	6196	407	0.059	35.545	0.443
W2 WIND PART>STRM	306.47	31.00	362.00	30	18%	100%	6087	109	0.059	35.578	0.119
W3 WIND DG>CLASS 33	292.94	30.08	1498.00	30	45%	100%	5823	264	0.059	151.730	0.288
W4 WIND SG>CLASS 33 AFT W1	278.50	30.08	840.00	30	48%	100%	5541	282	0.059	85.082	0.307
ACH .6>.5	266.26	12.24	120.00	10	100%	100%	5303	239	0.125	62.676	0.260
DOOR INSUL	256.18	11.20	300.00	30	90%	100%	5106	197	0.059	81.609	0.214
HEAT PUMP	238.57	23.47	2075.00	15	75%	100%	4763	343	0.091	414.089	0.374
CLOCK THERMOSTAT	229.07	12.67	147.00	15	75%	100%	4577	185	0.091	54.350	0.202

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	1350
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

9747	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
39%	FUEL FACTOR
30%	TAKE-BACK FACTOR
-6517.59	ENERGY USE CONVERSION CONSTANT (KWH/YR)
45.89082	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	587.00	---	---	---	---	---	12497	---	---	0.000	0.000
WALLS R0>R11	569.78	132.44	586.38	50	13%	100%	12159	338	0.048	10.890	0.377
WALLS R6>11	566.75	12.13	545.94	50	25%	100%	12099	60	0.048	110.698	0.066
F1 FLOOR R0>R19	516.33	112.05	648.00	50	45%	100%	11108	991	0.048	14.224	1.103
F2 FLOOR R11>19	511.83	23.65	594.00	50	19%	100%	11020	88	0.048	61.775	0.098
C1 CEIL R8>38	504.72	64.67	931.50	50	11%	100%	10880	140	0.048	35.427	0.156
C2 CEIL R13>38	494.29	47.39	864.00	50	22%	100%	10675	205	0.048	44.842	0.228
C3 CEIL R21>38	493.32	19.58	742.50	50	5%	100%	10655	19	0.048	93.270	0.021
C4 CEIL R37>38	493.25	2.16	607.50	50	3%	100%	10654	1	0.048	691.750	0.001
C5 CEIL R8>49	486.70	72.77	1174.50	50	9%	100%	10525	129	0.048	39.697	0.143
C6 CEIL R13>49	476.16	55.49	1107.00	50	19%	100%	10318	207	0.048	49.067	0.231
C7 CEIL R21>49	475.05	27.67	985.50	50	4%	100%	10296	22	0.048	87.600	0.024
C8 CEIL R37>49	474.74	10.24	702.00	50	3%	100%	10290	6	0.048	168.614	0.007
C3 CEIL R38>49	472.40	8.10	634.50	50	29%	100%	10244	46	0.048	192.665	0.051
W1 WIND SG>STORM	461.55	83.44	1043.00	30	13%	100%	10031	213	0.059	37.779	0.237
W2 WIND PART>STRM	442.89	60.20	752.50	30	31%	100%	9664	367	0.059	37.779	0.408
W3 WIND DG>CLASS 33	414.76	47.68	2375.00	30	59%	100%	9111	553	0.059	150.544	0.615
W4 WIND SG>CLASS 33 AFTER W1	396.64	47.68	1332.00	30	38%	100%	8755	356	0.059	84.431	0.396
ACH .6>.5	377.20	19.44	120.00	10	100%	100%	8373	382	0.125	39.146	0.425
DOOR INSUL	367.12	11.20	300.00	30	90%	100%	8174	198	0.059	80.954	0.220
HEAT PUMP	337.66	39.27	2075.00	15	75%	100%	7595	579	0.091	245.525	0.644
CLOCK THERMOSTAT	328.24	12.57	147.00	15	75%	100%	7410	185	0.091	54.350	0.206

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	2100
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

6293	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
50%	FUEL FACTOR
30%	TAKE-BACK FACTOR
-10453.8	ENERGY USE CONVERSION CONSTANT (KWH/YR)
44.86472	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	852.00	---	---	---	---	---	13941	---	---	0.000	0.000
WALLS R0>R11	802.38	198.47	878.70	50	25%	100%	13159	782	0.048	13.579	0.562
WALLS R6>11	800.02	18.18	802.95	50	13%	100%	13122	37	0.048	135.463	0.027
C1 CEIL R17>38	798.59	20.44	483.00	50	7%	100%	13099	23	0.048	72.476	0.016
C2 CEIL R19>38	798.15	14.70	483.00	50	3%	100%	13092	7	0.048	100.775	0.005
C3 CEIL R17>49	794.14	28.64	609.00	50	14%	100%	13029	63	0.048	65.218	0.045
C4 CEIL R19>49	792.53	22.90	574.00	50	7%	100%	13004	25	0.048	76.878	0.018
C5 CEIL R35>49	790.89	8.20	427.00	50	20%	100%	12978	26	0.048	159.713	0.019
W1 WIND SG>STORM	728.65	163.80	2205.00	50	38%	100%	11996	981	0.048	41.288	0.705
W2 WIND PART>STRM	690.70	97.30	1309.81	30	39%	100%	11398	598	0.059	50.734	0.430
W3 WIND DG>CLASS 33	666.51	100.80	5021.00	30	24%	100%	11017	381	0.059	187.730	0.274
W4 WIND SG>CLASS 33 AFT W1	589.90	100.80	2816.00	30	76%	100%	9809	1208	0.059	105.287	0.868
ACH .6>.5	557.14	32.76	120.00	10	100%	100%	9292	516	0.125	28.967	0.371
DOOR INSUL	547.06	11.20	150.00	30	90%	100%	9134	159	0.059	50.475	0.114
HEAT PUMP	482.63	85.92	2075.00	15	75%	100%	8118	1016	0.091	139.956	0.730
CLOCK THERMOSTAT	470.87	15.67	147.00	15	75%	100%	7932	185	0.091	54.350	0.133
HEAT PUMP	414.73	112.28	2800.00	15	50%	100%	7047	885	0.091	144.511	0.636

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

10192	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
19%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-5473.05	ENERGY USE CONVERSION CONSTANT (KWH/YR)
42.63857	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	471.00	---	---	---	---	---	11805	---	---	0.000	0.000
SUPER G.S. ENVELOPE	385.00	86.00	1695.00	70	100%	100%	8842	2963	0.045	25.580	3.447
ROOF R38>R49 ADV	374.00	11.00	392.00	70	100%	100%	8463	379	0.045	46.252	0.441
WALL R22>R26 ADV	350.00	24.00	802.00	70	100%	100%	7636	827	0.045	43.371	0.962
SOLAR ORIENT.	321.96	28.04	26.00	70	100%	100%	6670	966	0.045	1.203	1.124
SOLAR WINDOWS	317.57	4.39	20.00	70	100%	100%	6519	151	0.045	5.913	0.176
SGC WINDOWS & DOOR	228.57	89.00	1245.00	30	100%	100%	3452	3066	0.059	24.126	3.567
WALL R26 A>R40 BDW	211.57	17.00	1590.00	70	100%	100%	2867	586	0.045	121.390	0.681
CLASS 33 WINDOW AFTER SGC	194.07	17.50	406.00	30	100%	100%	2264	603	0.059	40.012	0.701

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

DATE OF RUN: 28-Jan-92

5816 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

19% FUEL FACTOR

0% TAKE-BACK FACTOR

-6733.87 ENERGY USE CONVERSION CONSTANT (KWH/YR)

43.75055 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1848
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	628.00	---	---	---	---	---	16718	---	---	0.000	0.000
SUPER G.S. ENVELOPE	532.00	96.00	2056.00	70	100%	100%	13332	3385	0.045	27.157	2.248
ROOF R38>R49 ADV	519.00	13.00	441.00	70	100%	100%	12874	458	0.045	43.016	0.304
WALL R22>R26 ADV	481.00	38.00	1287.00	70	100%	100%	11534	1340	0.045	42.946	0.890
SOLAR ORIENT.	452.15	28.85	26.00	70	100%	100%	10517	1017	0.045	1.143	0.675
SOLAR WINDOWS	436.32	15.83	20.00	70	100%	100%	9958	558	0.045	1.602	0.371
SGC WINDOWS & DOOR	326.32	110.00	1334.00	30	100%	100%	6080	3879	0.059	20.434	2.575
WALL R26 A>R40 BDW	299.32	27.00	2546.00	70	100%	100%	5127	952	0.045	119.571	0.632
CLASS 33 WINDOW AFTER SGC	275.32	24.00	557.00	30	100%	100%	4281	846	0.059	39.105	0.562

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-SINGLE FAMILY HOMES

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	2352
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

10672	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
25%	FUEL FACTOR
0%	TAKE-BACK FACTOR
-8256.22	ENERGY USE CONVERSION CONSTANT (KWH/YR)
42.97208	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	721.00	---	---	---	---	---	17068	---	---	0.000	0.000
SUPER G.S. ENVELOPE	627.00	94.00	1574.00	70	100%	100%	14034	3034	0.045	23.201	3.696
ROOF R38>R49 ADV	613.00	14.00	472.00	70	100%	100%	13582	452	0.045	46.713	0.550
WALL R22>R26 ADV	583.00	30.00	1028.00	70	100%	100%	12614	968	0.045	47.478	1.179
SOLAR ORIENT.	541.70	41.30	26.00	70	100%	100%	11281	1333	0.045	0.872	1.624
SOLAR WINDOWS	518.76	22.94	20.00	70	100%	100%	10541	740	0.045	1.208	0.902
SGC WINDOW	372.76	146.00	1810.00	30	100%	100%	5829	4712	0.059	22.825	5.740
WALL R26 A>R40 BDW	351.76	21.00	2036.00	70	100%	100%	5152	678	0.045	134.333	0.826
CLASS 33 WINDOW AFTER SGC	325.96	25.80	598.00	30	100%	100%	4319	833	0.059	42.674	1.014
BASEMENT	294.08	31.88	1098.00	70	100%	100%	3290	1029	0.045	47.721	1.253

FOR THE YEAR: 2012 — CONSERVATION SUPPLY PLANNING SPREAD SHEET -MOBILE HOMES

DATA OF RUN: 28-Jan-92

1,083	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
46.60%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-5099.79	ENERGY USE CONVERSION CONSTANT (KWH/YR)
58.38	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	924
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	476	---	---	---	---	---	12116	---	---	0.000	0.000
W1 WIND SG>STORM	385	90.70	$1,171.00	30	100%	100%	10137	1979	0.059	35.152	0.245
W3 CLASS 33 WINDOWS AFTER W1	339	46.12	1127.00	30	100%	100%	9130	1006	0.059	66.532	0.124
ACH .6>.4	313	26.60	119.00	10	100%	100%	8550	580	0.125	25.558	0.072
INSUL. ROOF	296	47.20	2400.00	30	35%	100%	8189	361	0.059	138.442	0.045

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET -MOBILE HOMES

DATA OF RUN: 28-Jan-92

655 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

41.50% FUEL FACTOR

0.00% TAKE-BACK FACTOR

-5099.79 ENERGY USE CONVERSION CONSTANT (KWH/YR)

58.38 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	924
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	366	---	---	---	---	---	9517	---	---	0.000	0.000
NEW HUD STANDARD	322	44.00	$895.00	45	100%	100%	8014	1503	0.050	29.789	0.112
HUD > MCS	229	93.00	2194.00	45	100%	100%	4838	3176	0.050	34.549	0.237
FLOOR R33>R44	219	10.00	249.00	45	100%	100%	4496	342	0.050	36.465	0.026
ATTIC R38>R49	218	1.00	130.00	45	100%	100%	4462	34	0.050	190.382	0.003
VAULT R33>R38	217	1.00	84.00	45	100%	100%	4428	34	0.050	123.016	0.003
CLASS 33 WINDOWS AFTER MCS	203	14.40	386.00	45	100%	100%	3936	492	0.050	39.256	0.037

FOR THE YEAR: 2012 — CONSERVATION SUPPLY PLANNING SPREAD SHEET-MOBILE HOMES

DATA OF RUN: 28-Jan-92

496	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
41.50%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-7933.87	ENERGY USE CONVERSION CONSTANT (KWH/YR)
62.29	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	480	---	---	---	---	---	12850	---	---	0.000	0.000
NEW HUD STANDARD	404	76.00	$1,486.00	45	100%	100%	10912	1939	0.050	38.338	0.110
HUD > MCS	283	121.00	2675.00	45	100%	100%	7825	3087	0.050	43.347	0.175
FLOOR R33>R44	266	17.00	423.00	45	100%	100%	7392	434	0.050	48.788	0.025
ATTIC R38>R49	263	3.00	295.00	45	100%	100%	7315	77	0.050	192.806	0.004
VAULT R33>R38	261	2.00	106.00	45	100%	100%	7264	51	0.050	103.919	0.003
CLASS 33 WINDOWS AFTER MCS	247	14.50	389.00	45	100%	100%	6894	370	0.050	52.602	0.021

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET -MOBILE HOMES

DATA OF RUN: 28-Jan-92

22,468	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
54.40%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-4249.22	ENERGY USE CONVERSION CONSTANT (KWH/YR)
33.81	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	924
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	463	---	---	---	---	---	5200	---	---	0.000	0.000
W1 WIND SG>STORM	372	90.70	$1,171.00	30	100%	100%	4221	979	0.059	71.089	2.510
W3 CLASS 33 WINDOWS AFTER W1	326	46.12	1127.00	30	100%	100%	3723	498	0.059	134.551	1.276
ACH .6>.4	300	26.60	119.00	10	100%	100%	3436	287	0.125	51.687	0.736
INSUL. ROOF	283	47.20	2400.00	30	35%	100%	3258	178	0.059	279.977	0.457

FOR THE YEAR: 2012	CONSERVATION SUPPLY PLANNING SPREAD SHEET -MOBILE HOMES	
DATA OF RUN: 28-Jan-92	29,222	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
	36.00%	FUEL FACTOR
	0.00%	TAKE-BACK FACTOR
	-4249.22	ENERGY USE CONVERSION CONSTANT (KWH/YR)
	33.81	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	924
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	366	---	---	---	---	---	5199	---	---	0.000	0.000
NEW HUD STANDARD	322	44.00	$895.00	45	100%	100%	4247	952	0.050	47.022	3.176
HUD > MCS	229	93.00	2194.00	45	100%	100%	2235	2012	0.050	54.537	6.712
FLOOR R33>R44	219	10.00	249.00	45	100%	100%	2019	216	0.050	57.562	0.722
ATTIC R38>R49	218	1.00	130.00	45	100%	100%	1997	22	0.050	300.523	0.072
VAULT R33>R38	217	1.00	84.00	45	100%	100%	1975	22	0.050	194.184	0.072
CLASS 33 WINDOWS AFTER MCS	203	14.40	386.00	45	100%	100%	1664	312	0.050	61.967	1.039

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MOBILE HOMES

DATA OF RUN: 28-Jan-92

19,078	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
36.00%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-5946.89	ENERGY USE CONVERSION CONSTANT (KWH/YR)
36.42	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA UA (BTU/F/H)	FIRST INCRMT COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	480	---	---	---	---	---	7383	---	---	0.000	0.000
NEW HUD STANDARD	404	76.00	$1,486.00	45	100%	100%	6143	1240	0.050	59.931	2.701
HUD > MCS	283	121.00	2675.00	45	100%	100%	4169	1974	0.050	67.762	4.300
FLOOR R33>R44	266	17.00	423.00	45	100%	100%	3891	277	0.050	76.268	0.604
ATTIC R38>R49	263	3.00	295.00	45	100%	100%	3842	49	0.050	301.404	0.107
VAULT R33>R38	261	2.00	106.00	45	100%	100%	3810	33	0.050	162.452	0.071
CLASS 33 WINDOWS AFTER MCS	247	14.50	389.00	45	100%	100%	3573	237	0.050	82.230	0.515

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET -MOBILE HOMES

DATA OF RUN: 28-Jan-92

749	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
19.50%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-4672.23	ENERGY USE CONVERSION CONSTANT (KWH/YR)
50.52	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	924
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	463	---	---	---	---	---	15070	---	---	0.000	0.000
W1 WIND SG>STORM	372	90.70	$1,171.00	30	100%	100%	12488	2582	0.059	26.945	0.221
W3 CLASS 33 WINDOW AFTER W1	326	46.12	1127.00	30	100%	100%	11174	1313	0.059	50.999	0.112
ACH .6>.4	300	26.60	119.00	10	100%	100%	10417	757	0.125	19.591	0.065
INSUL. ROOF	283	47.20	2400.00	30	35%	100%	9947	470	0.059	106.119	0.040

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET -MOBILE HOMES

DATA OF RUN: 28-Jan-92

2,325 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

53.50% FUEL FACTOR

0.00% TAKE-BACK FACTOR

-4672.23 ENERGY USE CONVERSION CONSTANT (KWH/YR)

50.52 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	924
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	366	---	---	---	---	---	6426	---	---	0.000	0.000
NEW HUD STANDARD	322	44.00	$895.00	45	100%	100%	5392	1034	0.050	43.305	0.274
HUD > MCS	229	93.00	2194.00	45	100%	100%	3207	2185	0.050	50.225	0.580
FLOOR R33>R44	219	10.00	249.00	45	100%	100%	2972	235	0.050	53.011	0.062
ATTIC R38>R49	218	1.00	130.00	45	100%	100%	2949	23	0.050	276.762	0.006
VAULT R33>R38	217	1.00	84.00	45	100%	100%	2925	23	0.050	178.831	0.006
CLASS 33 WINDOWS AFTER MCS	203	14.40	386.00	45	100%	100%	2587	338	0.050	57.067	0.090

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MOBILE HOMES

DATA OF RUN: 28-Jan-92

997 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

53.50% FUEL FACTOR

30.00% TAKE-BACK FACTOR

-6823.64 ENERGY USE CONVERSION CONSTANT (KWH/YR)

53.99 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	480	---	---	---	---	---	8878	---	---	0.000	0.000
NEW HUD STANDARD	404	76.00	$1,486.00	45	100%	100%	7542	1336	0.050	55.648	0.152
HUD > MCS	283	121.00	2675.00	45	100%	100%	5416	2126	0.050	62.919	0.242
FLOOR R33>R44	266	17.00	423.00	45	100%	100%	5117	299	0.050	70.817	0.034
ATTIC R38>R49	263	3.00	295.00	45	100%	100%	5064	53	0.050	279.862	0.006
VAULT R33>R38	261	2.00	106.00	45	100%	100%	5029	35	0.050	150.841	0.004
CLASS 33 WINDOWS AFTER MCS	247	14.50	389.00	45	100%	100%	4774	255	0.050	76.353	0.029

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET -MOBILE HOMES

DATA OF RUN: 28-Jan-92

6,921	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
35.40%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-4672.23	ENERGY USE CONVERSION CONSTANT (KWH/YR)
50.52	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	924
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	463	---	---	---	---	---	12093	---	---	0.000	0.000
W1 WIND SG>STORM	372	90.70	$1,171.00	30	100%	100%	10021	2072	0.059	33.577	1.637
W3 CLASS 33 WINDOW AFTER W1	326	46.12	1127.00	30	100%	100%	8967	1054	0.059	63.551	0.832
ACH .6>.4	300	26.60	119.00	10	100%	100%	8360	608	0.125	24.413	0.480
INSUL. ROOF	283	47.20	2400.00	30	35%	100%	7982	377	0.059	132.238	0.298

FOR THE YEAR: CONSERVATION SUPPLY PLANNING SPREAD SHEET -MOBILE HOMES
2012

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	924
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATA OF RUN: 28-Jan-92

16,005	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
37.30%	FUEL FACTOR
0.00%	TAKE-BACK FACTOR
-4672.23	ENERGY USE CONVERSION CONSTANT (KWH/YR)
50.52	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

CONSERVATION MEASURE:	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	366	---	---	---	---	---	8665	---	---	0.000	0.000
NEW HUD STANDARD	322	44.00	$895.00	45	100%	100%	7271	1394	0.050	32.116	2.547
HUD > MCS	229	93.00	2194.00	45	100%	100%	4325	2946	0.050	37.248	5.383
FLOOR R33>R44	219	10.00	249.00	45	100%	100%	4008	317	0.050	39.314	0.579
ATTIC R38>R49	218	1.00	130.00	45	100%	100%	3976	32	0.050	205.254	0.058
VAULT R33>R38	217	1.00	84.00	45	100%	100%	3945	32	0.050	132.626	0.058
CLASS 33 WINDOWS AFTER MCS	203	14.40	386.00	45	100%	100%	3489	456	0.050	42.323	0.833

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MOBILE HOMES

DATA OF RUN: 28-Jan-92

6,958	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
37.30%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-6823.64	ENERGY USE CONVERSION CONSTANT (KWH/YR)
53.99	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	ANNUAL MEASURE SAVING (MW/YR)
BASE CASE	480	---	---	---	---	---	11970	---	---	0.000	0.000
NEW HUD STANDARD	404	76.00	$1,486.00	45	100%	100%	10170	1601	0.050	41.270	1.430
HUD > MCS	283	121.00	2675.00	45	100%	100%	7302	2867	0.050	46.662	2.277
FLOOR R33>R44	266	17.00	423.00	45	100%	100%	6899	403	0.050	52.520	0.320
ATTIC R38>R49	263	3.00	295.00	45	100%	100%	6828	71	0.050	207.553	0.056
VAULT R33>R38	261	2.00	106.00	45	100%	100%	6781	47	0.050	111.868	0.038
CLASS 33 WINDOWS AFTER MCS	247	14.50	389.00	45	100%	100%	6437	344	0.050	56.625	0.273

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MULTIFAMILY

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	840
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

2,244	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
32.80%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-4184.46	ENERGY USE CONVERSION CONSTANT (KWH/YR)
51.02	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR
279.8	BASE UA

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	280	---	---	---	---	---	6781	---	---	0.000	0.000
WALLS R0>R11	269	43.88	185.02	30	25%	100%	6519	262	0.059	10.439	0.067
F1 FLOOR R0>R19	262	26.45	153.12	30	27%	100%	6346	173	0.059	14.332	0.044
C1 CEIL R19>38	260	5.42	111.65	30	30%	100%	6307	39	0.059	51.024	0.010
C2 CEIL R38>49 AFT C1	259	2.64	57.42	30	30%	100%	6288	19	0.059	53.747	0.005
W1 WIND SG>STORM	239	45.60	665.00	30	44%	100%	5811	477	0.059	36.104	0.122
W3 WIND DG>CLASS 33	226	30.40	1514.30	30	44%	100%	5490	321	0.059	123.322	0.082
W4 WIND SG>CLASS33 AFT W1	221	30.40	849.30	30	16%	100%	5373	117	0.059	69.166	0.030
ACH .6>.5	207	13.77	154.17	10	100%	100%	5043	330	0.125	58.161	0.085
DOOR INSUL	206	1.38	150.00	30	90%	100%	5013	30	0.059	269.101	0.008
CEILING R17>R49	204	5.99	149.93	30	30%	100%	4970	43	0.059	61.968	0.011

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MULTIFAMILY

DATE OF RUN: 28-Jan-92

SOURCE OF DATA FOR SPREADSHEET:

STATE	MONTANA
ZONE	3
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	840
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

6,335	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
16.40%	FUEL FACTOR
0.00%	TAKE-BACK FACTOR
-3280.37	ENERGY USE CONVERSION CONSTANT (KWH/YR)
46.59	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR
201	BASE UA

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	201	---	---	---	---	---	5087	---	---	0.000	0.000
SGC ENVELOPE	174	27.50	56.00	70	100%	100%	4016	1071	0.045	2.338	0.775
SGC WINDOWS	131	42.80	477.00	30	100%	100%	2349	1667	0.059	17.000	1.206
ROOF R38>R49 A	127	3.80	143.00	70	100%	100%	2201	148	0.045	43.199	0.107
WALL R22>R26 A	118	8.60	301.00	70	100%	100%	1866	335	0.045	40.178	0.242
WALL R26 A>R40 DBL	112	6.00	292.00	70	100%	100%	1632	234	0.045	55.866	0.169
FLOOR R30>R48	111	1.30	127.00	70	100%	100%	1581	51	0.045	112.144	0.037
CLASS 33 WINDOW AFTER SGC	102	9.50	220.40	30	100%	100%	1211	370	0.059	35.389	0.268

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MULTIFAMILY

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	840
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

DATE OF RUN: 28-Jan-92

34,282 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

48.10% FUEL FACTOR

30.00% TAKE-BACK FACTOR

-2256.34 ENERGY USE CONVERSION CONSTANT (KWH/YR)

25.03 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

279.8 BASE UA

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	280	---	---	---	---	---	2464	---	---	0.000	0.000
WALLS R0>R11	269	43.88	185.02	30	25%	100%	2365	99	0.059	27.547	0.389
F1 FLOOR R0>R19	262	26.45	153.12	30	27%	100%	2299	65	0.059	37.820	0.256
C1 CEIL R19>38	260	5.42	111.65	30	30%	100%	2285	15	0.059	134.645	0.058
C2 CEIL R38>49 AFT C1	259	2.64	57.42	30	30%	100%	2277	7	0.059	141.829	0.028
W1 WIND SG>STORM	239	45.60	665.00	30	44%	100%	2097	181	0.059	95.274	0.708
W3 WIND DG>CLASS 33	226	30.40	1514.30	30	44%	100%	1975	122	0.059	325.429	0.476
W4 WIND SG>CLASS33 AFT W1	221	30.40	849.30	30	16%	100%	1931	44	0.059	182.518	0.173
ACH .6>.5	207	13.77	154.17	10	100%	100%	1806	125	0.125	153.477	0.490
DOOR INSUL	206	1.38	150.00	30	90%	100%	1794	11	0.059	710.116	0.044
CEILING R17>R49	204	5.99	149.93	30	30%	100%	1778	16	0.059	163.523	0.064

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MULTIFAMILY

DATE OF RUN: 28-Jan-92

27,804	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
12.70%	FUEL FACTOR
0.00%	TAKE-BACK FACTOR
-2238.32	ENERGY USE CONVERSION CONSTANT (KWH/YR)
25.08	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	840
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

201 BASE UA

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	201	---	---	---	---	---	2448	---	---	0.000	0.000
SGC ENVELOPE	174	26.83	569.00	70	100%	100%	1860	588	0.045	43.303	1.865
SGC WINDOWS	131	42.80	477.00	30	100%	100%	923	937	0.059	30.239	2.975
ROOF R38>R49 A	128	3.80	143.00	70	100%	100%	840	83	0.045	76.838	0.264
WALL R22>R26 A	119	8.60	301.00	70	100%	100%	651	188	0.045	71.465	0.598
WALL R26 A>R40 DBL	113	6.00	292.00	70	100%	100%	520	131	0.045	99.370	0.417
FLOOR R30>R48	112	1.30	127.00	70	100%	100%	491	28	0.045	199.473	0.090
CLASS 33 WINDOW AFTER SGC	102	9.50	220.40	30	100%	100%	283	208	0.059	62.947	0.660

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MULTIFAMILY

DATE OF RUN: 28-Jan-92

1,449	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
1.00%	FUEL FACTOR
30.00%	TAKE-BACK FACTOR
-3351.86	ENERGY USE CONVERSION CONSTANT (KWH/YR)
43.30	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR
279.8	BASE UA

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	840
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	280	---	---	---	---	---	8676	---	---	0.000	0.000
WALLS R0>R11	269	43.88	185.02	30	25%	100%	8348	328	0.059	8.349	0.054
F1 FLOOR R0>R19	262	26.45	153.12	30	27%	100%	8132	216	0.059	11.463	0.036
C1 CEIL R19>38	260	5.42	111.65	30	30%	100%	8083	49	0.059	40.810	0.008
C2 CEIL R38>49 AFT C1	259	2.64	57.42	30	30%	100%	8060	24	0.059	42.987	0.004
W1 WIND SG>STORM	239	45.60	665.00	30	44%	100%	7463	597	0.059	28.877	0.099
W3 WIND DG>CLASS 33	226	30.40	1514.30	30	44%	100%	7062	401	0.059	98.634	0.066
W4 WIND SG>CLASS33 AFT W1	221	30.40	849.30	30	16%	100%	6916	146	0.059	55.319	0.024
ACH .6>.5	207	13.77	154.17	10	100%	100%	6502	413	0.125	46.518	0.068
DOOR INSUL	206	1.38	150.00	30	90%	100%	6465	37	0.059	215.230	0.006
CEILING R17>R49	204	5.99	149.93	30	30%	100%	6411	54	0.059	49.562	0.009

FOR THE YEAR: CONSERVATION SUPPLY PLANNING SPREAD SHEET-MULTIFAMILY

2012

DATE OF RUN: 16,152 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

28-Jan-92

11.30% FUEL FACTOR

0.00% TAKE-BACK FACTOR

-2918.39 ENERGY USE CONVERSION CONSTANT (KWH/YR)

39.91 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	840
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

201 BASE UA

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	201	---	---	---	---	---	4526	---	---	0.000	0.000
SGC ENVELOPE	174	27.50	569.00	70	100%	100%	3553	973	0.045	26.138	1.795
SGC WINDOWS	131	42.80	477.00	30	100%	100%	2038	1515	0.059	18.708	2.793
ROOF R38>R49 A	127	3.80	143.00	70	100%	100%	1903	135	0.045	47.538	0.248
WALL R22>R26 A	118	8.60	301.00	70	100%	100%	1599	304	0.045	44.214	0.561
WALL R26 A>R40 DBL	112	6.00	292.00	70	100%	100%	1386	212	0.045	61.478	0.392
FLOOR R30>R48	111	1.30	127.00	70	100%	100%	1340	46	0.045	123.409	0.085
CLASS 33 WINDOW AFTER SGC	102	9.50	220.40	30	100%	100%	1004	336	0.059	38.944	0.620

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MULTIFAMILY

DATE OF RUN: 28-Jan-92

9,576 NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE

32.10% FUEL FACTOR

30.00% TAKE-BACK FACTOR

-3351.86 ENERGY USE CONVERSION CONSTANT (KWH/YR)

43.30 ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR

279.8 BASE UA

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	840
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	280	---	---	---	---	---	5950	---	---	0.000	0.000
WALLS R0>R11	269	43.88	185.02	30	25%	100%	5726	225	0.059	12.173	0.246
F1 FLOOR R0>R19	262	26.45	153.12	30	27%	100%	5577	148	0.059	16.713	0.162
C1 CEIL R19>38	260	5.42	111.65	30	30%	100%	5544	33	0.059	59.502	0.037
C2 CEIL R38>49 AFT C1	259	2.64	57.42	30	30%	100%	5528	16	0.059	62.676	0.018
W1 WIND SG>STORM	239	45.60	665.00	30	44%	100%	5119	409	0.059	42.103	0.447
W3 WIND DG>CLASS 33	226	30.40	1514.30	30	44%	100%	4843	275	0.059	143.812	0.301
W4 WIND SG>CLASS33 AFT W1	221	30.40	849.30	30	16%	100%	4743	100	0.059	80.657	0.109
ACH .6>.5	207	13.77	154.17	10	100%	100%	4460	283	0.125	67.824	0.310
DOOR INSUL	206	1.38	150.00	30	90%	100%	4434	26	0.059	313.811	0.028
CEILING R17>R49	204	5.99	149.93	30	30%	100%	4397	37	0.059	72.263	0.040

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREAD SHEET-MULTIFAMILY

DATE OF RUN: 28-Jan-92

6,525	NUMBER OF HOMES IN SECTOR MATCHING PROTOTYPE
19.60%	FUEL FACTOR
0.00%	TAKE-BACK FACTOR
-2918.39	ENERGY USE CONVERSION CONSTANT (KWH/YR)
39.91	ENERGY USE CONVERSION SLOPE (KWH/(BTU/F/H))/YR
201	BASE UA

SOURCE OF DATA FOR SPREADSHEET:

STATE	WASHINGTON
ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	840
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

CONSERVATION MEASURE	UA (BTU/F/H)	DELTA U/A (BTU/F/H)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
BASE CASE	201	---	---	---	---	---	4103	---	---	0.000	0.000
SGC ENVELOPE	174	27.50	569.00	70	100%	100%	3220	882	0.045	28.836	0.657
SGC WINDOWS	131	42.80	477.00	30	100%	100%	1847	1373	0.059	20.639	1.023
ROOF R38>R49 A	127	3.80	143.00	70	100%	100%	1725	122	0.045	52.445	0.091
WALL R22>R26 A	118	8.60	301.00	70	100%	100%	1449	276	0.045	48.778	0.206
WALL R26 A>R40 DBL	112	6.00	292.00	70	100%	100%	1257	193	0.045	67.825	0.143
FLOOR R30>R48	111	1.30	127.00	70	100%	100%	1215	42	0.045	136.149	0.031
CLASS 33 WINDOW AFTER SGC	102	9.50	220.40	30	100%	100%	910	305	0.059	42.964	0.227

3. RESIDENTIAL APPLIANCES

3.1. Current Appliance Disaggregation

One of the problems in residential energy analysis is disaggregation of the residential loads into specific enduses or appliances. The disaggregation is necessary because the home is metered only at the whole house level. Breaking down residential consumption into enduses utilized several tools.

First, conditional demand models can be used for some enduses. The conditional demand model is used to estimate space heating, space cooling, water heating and a few other appliance loads. There are problems with this procedure. It is often the case that the regression model picks up collinearity between the presence of certain appliances. Thus, these results are supplemented with expert judgement.

The judgement takes the form of estimating typical appliance consumption from other references and multiplying by the saturation of the appliance. Saturation data are taken from the Company's "Energy Decisions" surveys. Since we are dealing with relatively small amounts of annual consumption, the assumed vacancy rate affects the results. The vacancy rate is larger than suggested by connect reports because empty homes can still have the electric service turned on. The most recent vacancy data came from the 1980 US Census, which is not a very recent survey. The Company attempted to use census data to estimate the amount of bias in connect reports in order to refine the vacancy assumption. The resulting appliance worksheet is shown in Table 7.

First, this table shows the saturations of the various appliances. Next, it shows the average consumption, that is, the product of typical consumption times the saturation of that particular appliance times 1 minus the vacancy rate. The last line shows the total annual average consumption for residential appliances in each state.

3.2. Appliance ECMs

Table 7 Residential Appliance Estimates

RESIDENTIAL ENDUSE DISAGGREGATION

APPLIANCE SATURATION

								UP&L	
	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
DHW	83%	89%	91%	71%	30%	86%	19%	77%	36%
REFRIGERATOR	103%	103%	100%	100%	100%	100%	100%	100%	100%
FREEZER	58%	63%	63%	65%	64%	58%	48%	67%	61%
CLOTHES DRYER	81%	84%	82%	84%	82%	79%	69%	85%	76%
RANGE	92%	96%	93%	92%	77%	87%	84%	90%	73%
HOT TUB	6%	5%	6%	4%	4%	6%	2%	4%	2%
WELL PUMP	22%	26%	23%	31%	12%	31%	0%	0%	0%
DISHWASHER	57%	60%	50%	57%	62%	51%	64%	52%	68%
CLOTHESWASHER	86%	89%	86%	88%	90%	87%	86%	90%	89%
WATERBED HEATER	21%	20%	18%	20%	36%	23%	20%	22%	23%
AIR CONDITIONER, WINDOW	14%	36%	7%	7%	9%	11%	6%	4%	2%
AIR CONDITIONER, CENTRAL	15%	27%	2%	4%	5%	8%	19%	4%	2%
AIR CONDITIONER, EVAP	5%	9%	3%	5%	31%	11%	54%	12%	6%
LIGHTS	100%	100%	100%	100%	100%	100%	100%	100%	100%
VACANCY RATE ASSUMPTION	8%	8%	9%	9%	12%	9%	9%	9%	9%

APPLIANCES

AVERAGE CONSUMPTION, kWh

	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
DHW	3054	3506	3094	2619	1121	2724	423	2594	1382
REFRIGERATOR	1358	1355	1295	1302	1261	1300	1295	1295	1295
FREEZER	496	538	530	550	524	489	404	563	513
CLOTHES DRYER	621	643	618	636	602	597	520	641	573
RANGE	516	537	512	510	413	481	463	496	402
HOT TUB	142	118	140	94	91	140	47	93	47
WELL PUMP	286	337	294	398	149	397	50	300	300
DISHWASHER	370	389	319	366	385	327	408	332	434
CLOTHESWASHER	504	520	495	509	504	502	495	518	512
WATERBED HEATER	194	185	164	183	319	210	182	200	209
AIR CONDITIONER, WINDOW	64	165	32	32	40	50	19	18	9
AIR CONDITIONER, CENTRAL	222	398	31	33	71	117	227	43	29
AIR CONDITIONER, EVAP	6	10	3	6	34	12	280	75	7
LIGHTS	1629	1626	1624	1606	1559	1606	1604	1611	1604
MISC	714	1035	817	697	436	480	276	1792	458
TOTAL APPLIANCES	10176	11362	9968	9541	7507	9432	6693	10571	7774

Predicting the savings potential from new appliances in problematic. Should one assume current levels of technology or the improved levels expected in the future? Should one base costs on the incremental or total replacement? In our study, we included a ECM to represent "High Technology" refrigerators and freezers. This option represents new products expected within the twenty year planning horizon, although not available now. We also assigned the cost for new appliances as the incremental cost. Cost and savings for these appliances were taken from USDOE Draft Rulemaking Proceedings as developed by Lawrence Berkeley Laboratory. These estimates result in a large technical potential estimate for the new appliance sector. Changeout of old appliances before the end of their lifetime was assigned full replacement cost, which means the ECM would not be cost-effective. More efficient clothesdryers and dishwashers are also assumed as future appliance options.

Technical potential is currently estimated conservatively by assuming 33% penetration of high-tech refrigerators and freezers. This reflects current experience that it is difficult to locate products with extremely high efficiency. Although such units are possible they are not available in today's marketplace. One would expect this assumption to change as more experience is gained regarding the market response to demand-side initiatives.

Another complication is the interaction of appliances and space heating. To a certain extent, the waste heat from appliance inefficiency contributes to space heating. If the appliances are more efficient, some additional space heating will be required. In the case of extremely tight modern houses, the utilizability of appliance waste heat could be considerable. Estimates of the utilizability for space heat was taken from work done for the Council by Lawrence Berkeley Laboratory. The net electric savings for appliance measures will depend to some extent on the saturation of electricity for space heating. Details of the space heating interaction are shown in Table 8.

Table 8 Space Heat Interaction

RESIDENTIAL ENDUSE DISAGGREGATION

SPACE HEAT INTERACTION ADJUSTMENT

MARKET SHARES					UP&L				
	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
EXISTING	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
EXIST WX	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
CURRENT NEW	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
MCS NEW	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28

USABILITY OF INTERNAL GAINS FROM LBL TRNSYS SIMULATION

GROSS ADJUSTMENT

	OREGON	WASH	IDAHO	MONT	WYOM	CALIF	UTAH	IDAHO	WYOM
EXISTING	0.62	0.64	0.64	0.69	0.64	0.62	0.60	0.64	0.69
EXIST WX	0.52	0.58	0.58	0.62	0.58	0.52	0.52	0.58	0.62
CURRENT NEW	0.53	0.58	0.58	0.61	0.58	0.53	0.52	0.58	0.61
MCS NEW	0.46	0.46	0.46	0.51	0.46	0.46	0.39	0.46	0.51
WEIGHTED TOTAL	0.51	0.55	0.55	0.59	0.55	0.51	0.49	0.55	0.59

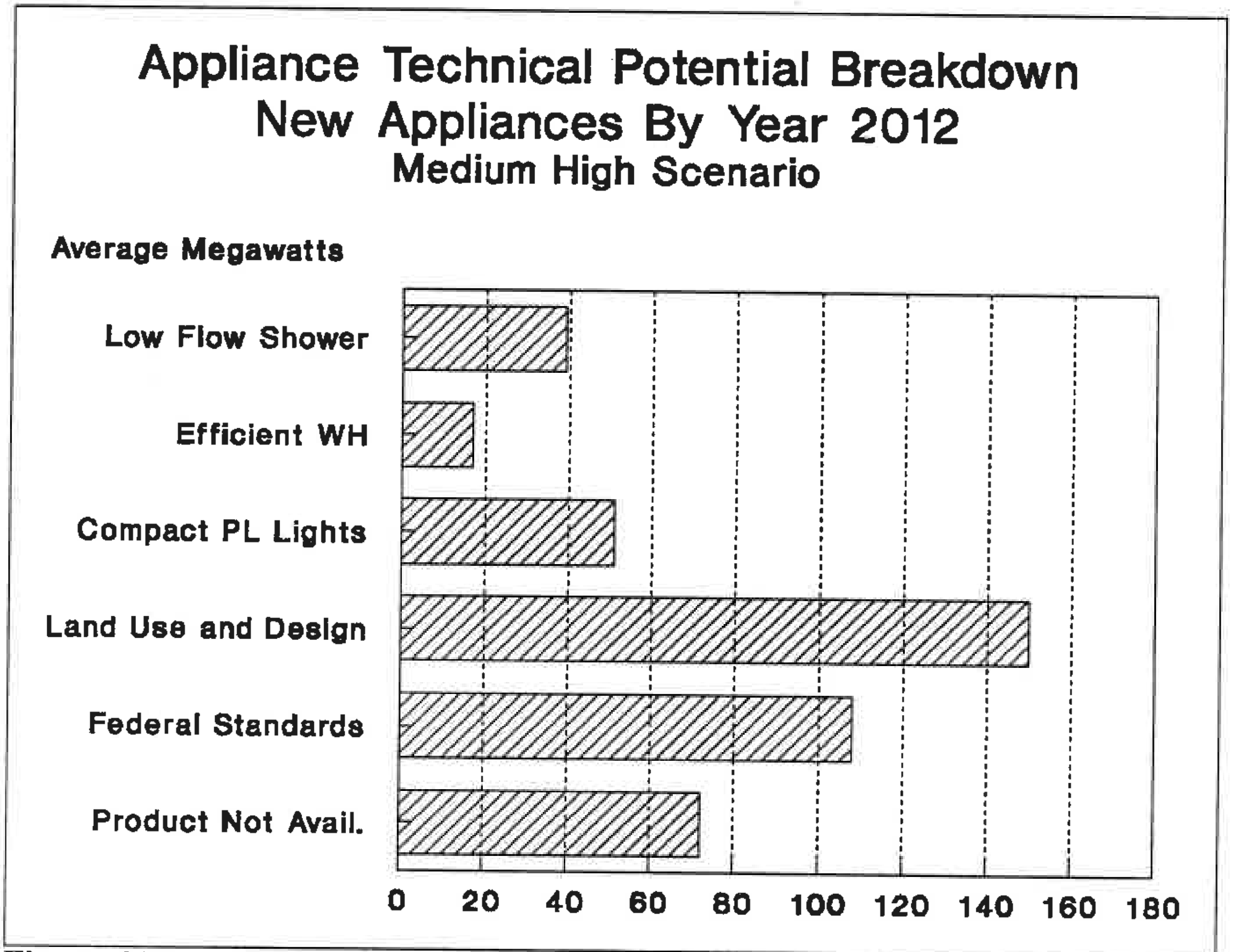


Figure 6 Breakdown of Appliance Potential

The technical potential for appliances is very high -- leaving one to wonder why more savings are not included in programs. The answer is that much of the potential is not immediately accessible. Figure 6 shows a breakdown of technical potential under one scenario. Water heat savings from the first two measures and lighting savings are considered within planned programs. Land use and design is savings from solar access and passive cooling. This resource is best addressed in a new construction program, although roof color and tree plantings are measures that can be considered for existing stock. The new residential construction program recognizes these potential benefits but they are outside the traditional scope of what most utility programs have included in the past. New Federal standards have recently been mandated for a variety of appliances. These savings will need to be included in future updates of the planning forecasts -- they are no longer available as programmatic savings. Finally, there is the category of products not yet available. A variety of product improvements have been identified as cost effective. However, these products are not yet available on the American market.

One expects that more efficient products will appear during the twenty year planning horizon, but they are not available yet.

3.3. Appliance Capacity Savings

To some extent, capacity savings depend on the type of measure and the coincidence of its savings with system peak. This coincidence is not clear for many appliances. In most cases, capacity savings were computed assuming a conservation load factor of 0.6. Savings from low flow showers are a notable exception. These savings are more likely to occur on-peak. There is also some seasonality of the savings since water heating load increases during the wintertime. These capacity savings are not itemized in the supply curve worksheets but are used in determining program impacts.

Another appliance option is the installation of load controls on appliances. The controls are designed to "lock out" the appliance during peak times unless overridden by the customer. The controls have little impact on energy but can save capacity during system peaks. Load controls for domestic hot water were considered as a draft program and are described in the Program Documentation.

3.4. Appliance Spreadsheets

Examples of the supply curve spreadsheets are shown for Oregon and Utah as representative states. There are two pages of potential measures, followed by a page that sorts the measures by levelized cost. Figure 7 summarizes potential savings estimates from appliances. Note that the older appliances are expected to die off and be replaced by more efficient ones. An example of the change in appliance stock is shown in Figure 7.

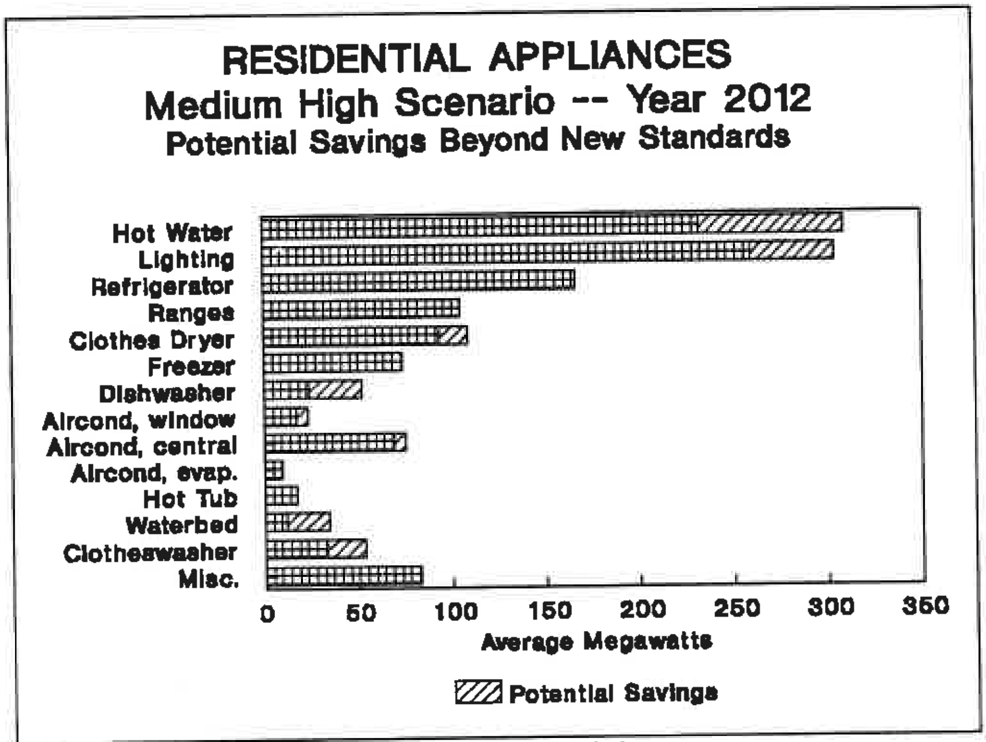


Figure 7 Appliance Technical Potential

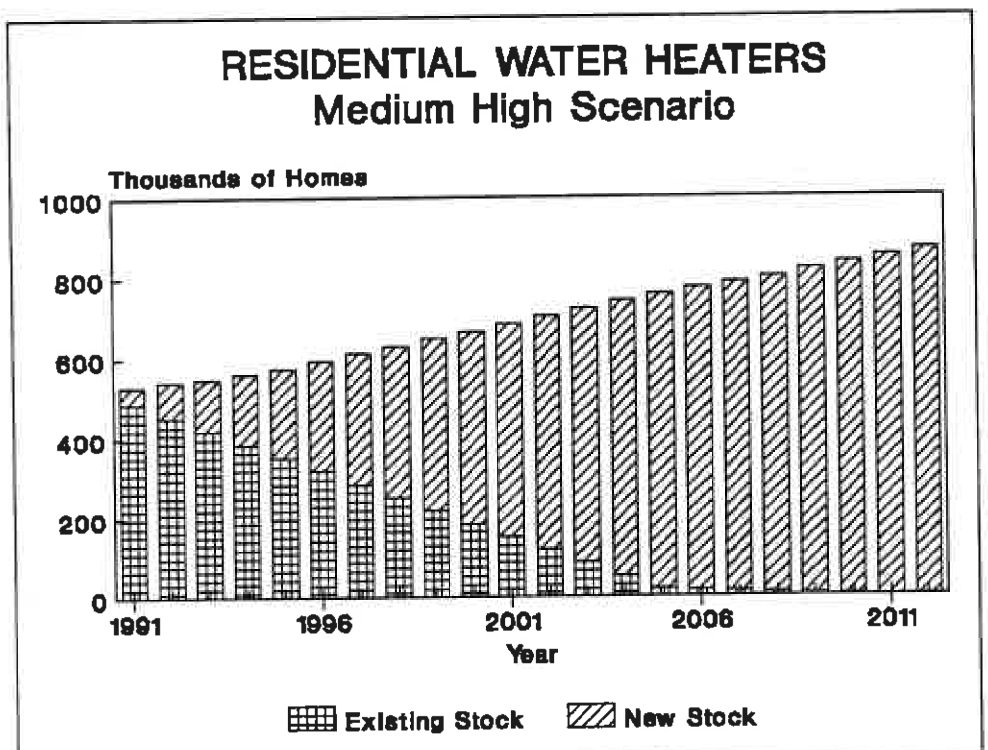


Figure 8 Water Heater Stock

FOR THE YEAR 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET-APPLIANCES

SOURCE OF DATA FOR SPREADSHEET.

DATE OF RUN: 30-Jan-92

447,540	Total lighting customers
447,518	Total number of ranges
284,402	Total number of dishwashers
437,101	Total number of clothesdryers
171,965	Total number of air conditioners, window
92,645	Total number of air conditioners, cemtral
63,050	Total number of air conditioners, evaporative
321,868	Total number of freezers
366,059	Total number of hot waterheaters
447,540	Total number of refrigerators
27,090	Total number of hot tubs
0	Total number of well pumps
75,032	Total number of waterbeds
438,140	Total number of clotheswashers

STATE	OREGON
ZONE	1
VINTAGE OF HOUSING	NEW
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

MEASURES APPLICABLE TO ALL LIGHTING:	SAVINGS (KWH/YR)	FIRST INCRMT. COST($)	O & M COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MW/YR)
	---	---	---	---	---	---	---	0.000	0.000
FIRST 3 INCAND. > PL	118.25	45.00	-12.99	10	100%	100%	0.125	33.752	6.037
ADD 3 INCAND. > PL	118.25	65.00	-12.99	10	100%	100%	0.125	54.839	6.037
MEASURES APPLICABLE TO ALL DISHWASHERS									
1993 DOE DISHWSHR RULES	113.75	15.75	-60.28	12	83%	100%	0.108	-42.261	3.063
DISHWASHER MEASURES	283.92	65.10	-71.92	12	83%	100%	0.108	-2.592	7.645
MEASURES APPLICABLE TO ALL CLOTHESDRYERS									
1993 DOE DRYER RULES	80.08	26.00	0.00	12	100%	100%	0.108	35.047	3.993
DRYER MEASURES	218.40	138.40	0.00	12	100%	100%	0.108	68.405	10.890
MEASURES APPLICABLE TO ALL CLOTHESWASHERS									
1993 DOE WASHER RULES	279.83	30.75	-88.13	12	58%	100%	0.108	-22.137	8.126
WASHER MEASURES	218.40	40.80	0.00	12	58%	100%	0.108	20.166	6.342
HORIZONTAL AXIS WASHER	432.25	200.00	-167.46	12	25%	100%	0.108	8.127	5.380
MEASURES APPLICABLE TO ALL COOLING									
ORIENTATION	352.09	20.00	0.00	70	100%	100%	0.045	2.540	13.160
ROOF COLOR, LANDSCPNG	270.88	100.00	0.00	70	100%	100%	0.045	16.507	10.125

MEASURES APPLICABLE									
TO ALL AIR CONDITIONERS									
EFFICIENT AC UPGRADE	72.83	100.00	0.00	15	70%	100%	0.091	125.446	0.539
MEASURES APPLICABLE									
TO ALL FREEZERS									
1990 FREEZER>1993 STAND.	104.87	41.00	5.50	15	100%	100%	0.091	40.508	4.379
1993 FREEZER>HI TECH	234.78	1200.00	12.31	15	100%	100%	0.091	471.741	9.804
MEASURES APPLICABLE									
TO ALL WATERHEATERS									
NEW .95 TANK	201.80	83.00	10.20	12	80%	100%	0.108	49.855	6.742
LOW FLOW SHOWERHEAD	566.93	10.00	-107.58	10	70%	100%	0.125	-21.459	16.572
H.P. DHW	486.85	1000.00	100.00	3	33%	100%	0.362	817.652	6.709
SOLAR DHW	2184.00	2800.00	0.00	20	33%	100%	0.075	96.221	30.096
EXHAUST AIR HP DHW	2215.85	1250.00	100.00	15	33%	100%	0.091	55.660	30.535
MEASURES APPLICABLE									
TO ALL REFRIGERATORS									
1990 REFER>1993 STAND.	132.86	170.00	16.41	15	100%	100%	0.091	128.183	6.783
1993 REFER>HI TECH	247.15	1676.00	30.20	15	100%	100%	0.091	630.699	12.618
1993 REFER>HI TECH	244.46	2379.00	31.83	15	50%	0%	0.091	0.000	0.000
MEASURES APPLICABLE									
TO ALL WATERBEDS									
INSULATED BEDFRAME	597.87	100.00	0.00	5	33%	100%	0.226	37.809	1.706

AVERAGE LEVELIZED COST (MILLS/KWH)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED MEASURE COST (MILLS/KWH)	UNIT CUMULATIVE SAVINGS (MW/YR)
	--------	---		
-42.261	1993 DOE DISHWASHER RULES	3.063	-42.261	3.063
-27.646	1993 DOE WASHER RULES	8.126	-22.137	11.189
-23.953	LOW FLOW SHOWERHEAD	16.572	-21.459	27.761
-19.340	DISHWASHER MEASURES	7.645	-2.592	35.407
-13.411	ORIENTATION	13.160	2.540	48.567
-11.263	HORIZONTAL AXIS WASHER	5.380	8.127	53.947
-6.875	ROOF COLOR, LANDSCAPING	10.126	16.507	64.072
-4.439	WASHER MEASURES	6.342	20.166	70.414
-1.424	FIRST 3 INCAND. > PL	6.037	33.752	76.451
0.387	1993 DOE DRYER RULES	3.993	35.047	80.444
1.164	INSULATED BEDFRAME	1.706	37.809	82.150
3.155	1990 FREEZER> 1993 STAND.	4.379	40.508	86.529
6.530	NEW .95 TANK	6.742	49.855	93.270
9.467	ADD 3 INCAND. > PL	6.037	54.839	99.307
20.330	EXHAUST AIR HP DHW	30.535	55.660	129.843
24.051	DRYER MEASURES	10.890	68.405	140.733
36.765	SOLAR DHW	30.096	96.221	170.829
37.044	EFFICIENT AC UPGRADE	0.539	125.446	171.368
40.514	1990 REFER> 1993 STANDARD	6.783	128.183	178.151
63.008	1993 FREEZER> HI TECH	9.804	471.741	187.955
98.721	1993 REFER> HI TECH	12.618	630.699	200.573
121.990	H.P. DHW	6.709	817.652	207.282

FOR THE YEAR: CONSERVATION SUPPLY PLANNING SPREADSHEET-APPLIANCES

2012

718,419	Total lighting customers
718,296	Total number of ranges
481,872	Total number of dishwashers
687,901	Total number of clothesdryers
96,620	Total number of air conditioners, window
234,243	Total number of air conditioners, cemtral
506,193	Total number of air conditioners, evaporative
467,271	Total number of freezers
120,009	Total number of hot waterheaters
718,419	Total number of refrigerators
16,042	Total number of hot tubs
0	Total number of well pumps
145,706	Total number of waterbeds
704,150	Total number of clotheswashers

DATE OF RUN:

30-Jan-92

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
ZONE	2
VINTAGE OF HOUSING	NEW
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL FINANCIAL RATE	9.54%

MEASURES APPLICABLE TO ALL LIGHTING:	SAVINGS (KWH/YR)	FIRST INCRMT. COST($)	O & M COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	LEVELIZED COST (MILLS/KWH)	VARIABLE MEASURE SAVING (MW/YR)
	---	---	---	---	---	---	---	0.000	0.000
FIRST 3 INCAND.> PL	150.64	45.00	-9.02	10	100%	100%	0.125	29.775	12.346
ADD 3 INCAND. > PL	150.64	65.00	-9.02	10	100%	100%	0.125	46.328	12.346
MEASURES APPLICABLE TO ALL DISHWASHERS									
1993 DOE DSHWSHR RULES	113.75	15.75	-60.28	12	83%	100%	0.108	-42.261	5.190
DISHWASHER MEASURES	283.92	65.10	-71.92	12	83%	100%	0.108	-2.592	12.954
MEASURES APPLICABLE TO ALL CLOTHESDRYERS									
1993 DOE DRYER RULES	80.08	26.00	0.00	12	100%	100%	0.108	35.047	6.284
DRYER MEASURES	218.40	138.40	0.00	12	100%	100%	0.108	68.405	17.139
MEASURES APPLICABLE TO ALL CLOTHESWASHERS									
1993 DOE WASHER RULES	279.83	30.75	-88.13	12	58%	100%	0.108	-22.137	13.059
WASHER MEASURES	218.40	40.80	0.00	12	58%	100%	0.108	20.166	10.193
HORIZONTAL AXIS WASHER	432.25	200.00	-167.46	12	25%	100%	0.108	8.127	8.646
MEASURES APPLICABLE TO ALL COOLING									
ORIENTATION	581.00	20.00	0.00	70	100%	100%	0.045	1.539	55.479
ROOF COLOR, LANDSCAPING	447.00	100.00	0.00	70	100%	100%	0.045	10.003	42.684

MEASURES APPLICABLE									
TO ALL AIR CONDITIONERS									
EFFICIENT AC UPGRADE	85.44	100.00	0.00	15	70%	100%	0.091	106.923	1.598
MEASURES APPLICABLE									
TO ALL FREEZERS									
1990 FREEZER>1993 STAND.	104.87	41.00	7.48	15	100%	100%	0.091	42.239	1.436
1993 FREEZER>HI TECH	234.78	1200.00	16.76	15	100%	100%	0.091	473.471	3.214
MEASURES APPLICABLE									
TO ALL WATERHEATERS									
NEW .95 TANK	248.98	83.00	13.82	12	80%	100%	0.108	41.979	2.727
LOW FLOW SHOWERHEAD	566.93	10.00	-112.29	10	70%	100%	0.125	-22.495	5.433
H.P. DHW	486.85	1000.00	100.00	3	33%	100%	0.362	817.652	2.199
SOLAR DHW	3276.00	2800.00	0.00	20	33%	100%	0.075	64.147	14.800
EXHAUST AIR HP DHW	2215.85	1250.00	100.00	15	33%	100%	0.091	55.660	10.011
MEASURES APPLICABLE									
TO ALL REFRIGERATORS									
1990 REFER>1993 STANDARD	169.26	170.00	22.29	15	100%	100%	0.091	103.789	13.872
1993 REFER>HI TECH	314.86	1676.00	41.01	15	100%	100%	0.091	498.203	25.804
1993 REFER>HI TECH	311.44	2379.00	41.01	15	50%	0%	0.091	0.000	0.000
MEASURES APPLICABLE									
TO ALL WATERBEDS									
INSULATED BEDFRAME	761.67	100.00	0.00	5	33%	100%	0.226	29.678	4.220

AVERAGE LEVELIZED COST (MILLS/KWH)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED MEASURE COST (MILLS/KWH)	CUMULATIVE SAVINGS (MW/YR)
	--------	---		
-42.261	1993 DOE DISHWASHER RULES	5.190	-42.261	5.190
-32.152	LOW FLOW SHOWERHEAD	5.433	-22.495	10.623
-26.629	1993 DOE WASHER RULES	13.059	-22.137	23.682
-18.130	DISHWASHER MEASURES	12.954	-2.592	36.636
-6.284	ORIENTATION	55.479	1.539	92.115
-5.047	HORIZONTAL AXIS WASHER	8.646	8.127	100.761
-0.569	ROOF COLOR, LANDSCAPING	42.684	10.003	143.445
0.807	WASHER MEASURES	10.193	20.166	153.637
1.579	INSULATED BEDFRAME	4.220	29.678	157.858
3.624	FIRST 3 INCAND. > PL	12.346	29.775	170.203
4.743	1993 DOE DRYER RULES	6.284	35.047	176.488
5.309	NEW .95 TANK	2.727	41.979	179.214
5.603	1990 FREEZER> 1993 STAND.	1.436	42.239	180.650
8.208	ADD 3 INCAND. > PL	12.346	46.328	192.996
10.548	EXHAUST AIR HP DHW	10.011	55.660	203.007
14.190	SOLAR DHW	14.800	64.147	217.807
18.145	DRYER MEASURES	17.139	68.405	234.946
22.920	1990 REFER> 1993 STANDARD	13.872	103.789	248.817
23.456	EFFICIENT AC UPGRADE	1.598	106.923	250.416
29.159	1993 FREEZER> HI TECH	3.214	473.471	253.630
72.473	1993 REFER> HI TECH	25.804	498.203	279.434
78.292	H.P. DHW	2.199	817.652	281.634

4. COMMERCIAL SECTOR

The methodology for commercial sector is based on a series of prototype buildings modeled for Bonneville using the DOE-2 program by United Industries Corporation (UIC). This work was updated by the consultants under the name SBW Consulting, Inc. in 1990, however we continued to refer to the analysis under the name UIC. The building model developed for the Lodging segment was a 12-story hotel. This prototype is not appropriate to the Company's service territory. A new prototype based on a 35-unit motel, originally modeled by Ecotope, was used for modeling this segment.

There was fairly extensive effort in identifying the end-use splits in these buildings. For the most part, the end-use splits agree with our own marketing study (The Commercial Evaluation Project: Market Structure and Segmentation, conducted 1988 for PP&L by Western Economic Services). Both these studies rely heavily on ELCAP commercial data. An additional set of end-use splits was supplied by Charlie Grist, Oregon Department of Energy, based on their independent study. All these end-use splits are compared against the enduse assumptions in the data sheets. We found it helpful to have a reality check when reviewing the ECMs. Pacific's enduse splits are similar to Regional ones based on ELCAP monitoring. The ODOE splits are somewhat different, due to a different source of data, but not inconsistent.

New buildings include two end-use splits for reference. The current practice column is that reported by UIC as current code in 1990. The MCS column is that reported by UIC to represent the same buildings under current versions of the MCS commercial code. Even though Oregon and Washington codes are considered to be MCS equivalent, they appear to be less energy efficient than the MCS level. This is demonstrated by the differences between the current practice and MCS columns. New code hearings will be underway shortly to refine and improve the MCS. Any new changes are not yet included in the end-use model.

The resulting ECM costs and savings from the UIC analysis are suitable for initial study. A few additional measures were added because they seemed too important to overlook. Those included retrofit refrigeration upgrades and changeout of incandescent beyond halogen bulbs to compact fluorescent lights.

The proper level of baseline use for new buildings is fuzzy. New buildings are supposed to be at the MCS level. However, as previously discussed, it does not appear that current practice is in compliance. Therefore, a measure of "current>MCS" was included for enduses where an upgrade was implied. Acceptance of the commercial MCS can be modeled by choosing appropriate penetration rates for this measure.

The building stock in the Company's territory differs from that of most other utilities. The Company serves many small, rural towns. As a result, the building stock is older and very small by traditional standards. It also appears to be poorly insulated. Space heat is much higher than one would expect for commercial structures, even though electric space heat has low saturation. There is little space cooling. This rules out an energy bonus for measures that reduce internal gains. Downsizing credits are also unlikely since they result primarily from savings for cooling equipment.

The sheets below list enduse split assumptions for commercial buildings. For reference, the UIC and ODOE splits are also listed, although not utilized in the calculations. Notice that cost, savings and acceptance factor are all based on square footage. Measures are classified into structure, lighting and equipment categories. At the bottom of each category is shown the total energy, fraction of appropriate enduse and average cost for measures within a 55 mill/KWh ceiling.

The forecast assumes that 85% of new buildings will comply with new commercial code. 15% will be equivalent to current practice.

4.1. Climate Zones

Commercial buildings are only slightly sensitive to climate. This is because there is a low saturation of electric space heat and low cooling usage. Lighting and receptacle loads are not affected by climate. The climate adjustments from the UIC study are listed below for existing buildings. End uses for other climate zones are based on Zone 1 usage multiplied times the appropriate factor. There are other climatic considerations which are not addressed. The basecase building varies between climate zone. The variation is not always in line with rationality since it is dominated by what the local building community considers "accepted practice". Due to lack of resolution in the survey data, we did not attempt to adjust the basecase buildings to different localities. A generic building is assumed based on the company's total commercial usage. For new buildings, an updated analysis by SBW Consulting served to define the baseline and measures.

4.2. Commercial Building Spreadsheets

Examples of the commercial spreadsheets are shown for Oregon, Washington, Montana and Utah as representative states. Figure 9 summarizes potential savings for existing commercial stock. Figure 10 summarizes potential for new commercial buildings.

Table 9 UIC Climate Adjustments

Climatic Adjustment Factors for Existing Buildings

Zone 2

Segment	Heating	Cooling	Ventilation
Office	1.38	1.85	1.45
Retail	1.28	2.72	1.15
Grocery	1.10	2.64	2.84
Restaurant	1.15	1.62	1.01
School	1.03	--	1.13
Hospital	1.15	1.40	1.01
Warehouse	1.39	1.56	1.22
Hotel	1.04	1.32	1.04

Zone 3

Segment	Heating	Cooling	Ventilation
Office	1.89	1.33	1.44
Retail	1.94	1.72	1.08
Grocery	1.48	1.64	2.84
Restaurant	1.56	1.19	1.00
School	1.26	--	1.09
Hospital	1.23	0.92	0.99
Warehouse	2.02	1.15	1.46
Hotel	1.21	0.98	0.98

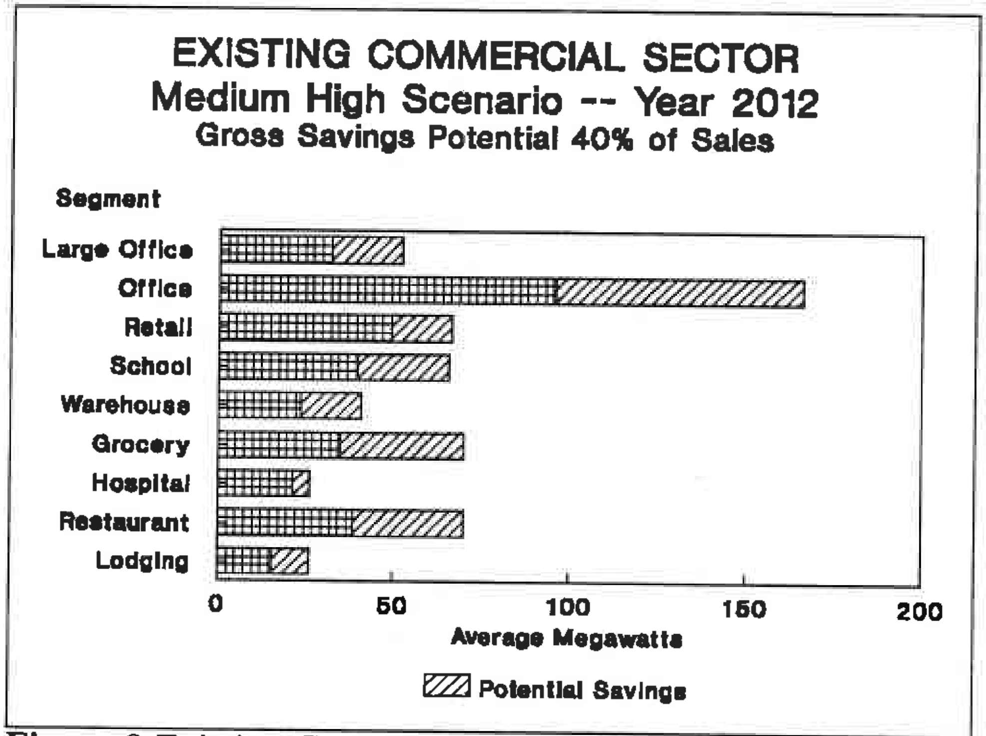


Figure 9 Existing Commercial Savings Potential

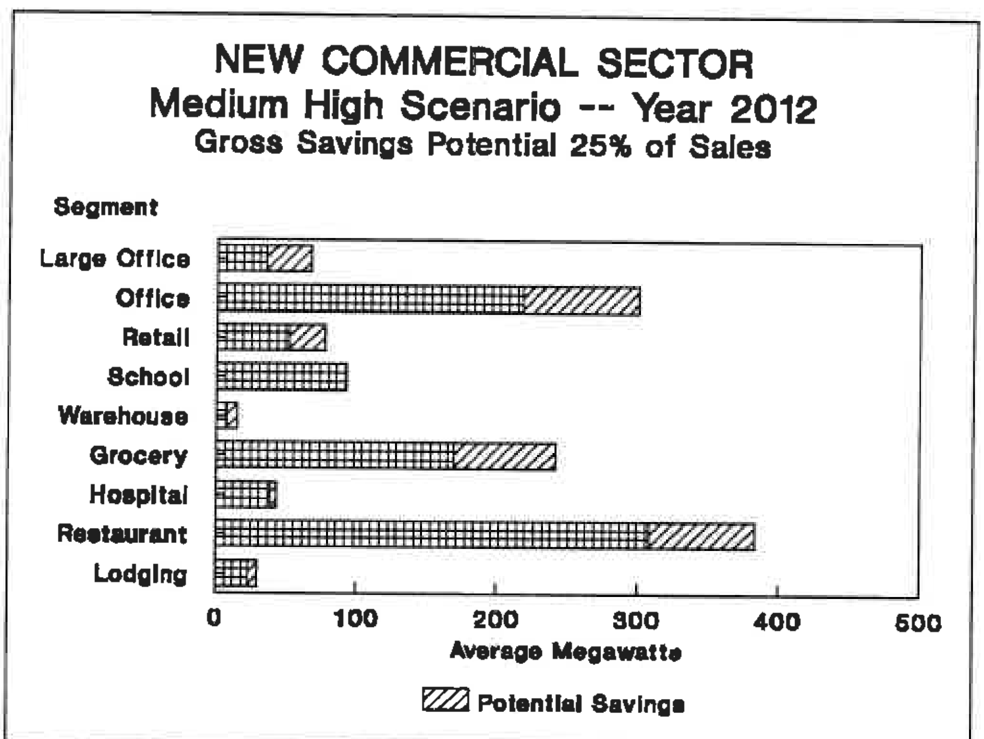


Figure 10 New Commercial Savings Potential

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	2,624	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		FAST FOOD
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% SAT.	ALL FUELS (KWH/SF)	UIC PROTOTYPE (KWH/SF)
HEATING	11.36	37.0%	30.71	29.40
COOLING	0.96	73.0%	1.32	5.05
VENTILATION	8.60	100.0%	8.60	6.29
WATER HEAT	1.65	48.0%	3.43	8.76
REFRIGERATION	3.00	100.0%	3.00	
LIGHTING	8.79	100.0%	8.79	7.60
MISC.	1.05	30.0%	3.49	55.82
TOTAL	35.41	61.9%	59.34	112.92

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R6>R26	0.6450	0.0000	3.3880	30	37%	0.0113	1.2535	0.2386	0.0000
INSULATE WALL R7>R19	6.8359	0.0000	4.1761	30	37%	0.0972			
EFF. WINDOWS SG>LOW E	2.6969	0.0000	2.0991	30	37%	0.0763			
SOLAR FILM	0.3514	0.0000	0.8899	7	73%	0.0663			
					TOTAL	0.0113	1.2535	0.2386	0.0000
					% OF ENDUSE		10.2%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	1.1378	0.2995	2.3834	15	100%	0.0551	2.3834	1.1378	0.2995
INCANDESCENT>PL	0.7954	-0.2381	2.5962	15	100%	0.0196	2.5962	0.7954	-0.2381
					TOTAL	0.0196	4.9797	1.9332	0.0614
					% OF ENDUSE		56.7%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
AAHX (DINING RM)	0.5506	0.0000	1.1490	15	37%	0.0438	0.4251	0.2037	0.0000
EFFICIENT EXHAUST HOOD	7.7081	0.0000	16.3491	15	37%	0.0431	6.0492	2.8520	0.0000
HEAT PUMP (DINING RM)	6.4234	0.0000	3.6631	15	37%	0.1602			
HW HEAT RECOVERY	1.8856	0.0000	8.7652	15	19%	0.0196	1.6474	0.3544	0.0000
HW BLANKET	0.0243	0.0000	0.0469	10	19%	0.0645			
HW TIME CLOCK	0.0265	0.0000	0.0202	20	19%	0.0983			
FREEZER STRIP CURTAIN	0.1293	0.0000	1.5812	3	100%	0.0296	1.5812	0.1293	0.0000
ECONOMIZER	2.2950	0.0000	0.7241	15	73%	0.2895			
					TOTAL	0.0383	9.7029	3.5393	0.0000
					% OF ENDUSE		36.4%		
					GRAND TOTAL	0.0315	15.936071923	5.71119	0.06144
							45.0%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	2,624	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		FAST FOOD
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAV	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	3.66	37.0%	9.87	10.00
COOLING	1.83	52.0%	3.49	3.70
VENTILATION	10.90	100.0%	10.90	10.90
WATER HEAT	4.22	48.0%	8.80	8.80
REFRIGERATION	15.10	100.0%	15.10	15.10
LIGHTING	13.85	100.0%	13.27	17.10
MISC.	13.12	92.9%	6.50	57.30
TOTAL	62.68	92.3%	67.93	122.90

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0236	0.0000	0.1330	70	20%	0.0079			
INSUL. ROOF R19>R30	0.2890	0.0000	0.3136	30	20%	0.0547			
SOLAR FILM	0.3701	0.0000	0.6753	7	75%	0.0921			
WINDOWS LOW E	0.3176	0.0000	0.4992	20	20%	0.0477			
							0.0627	0.0578	0.0000
							0.0998	0.0635	0.0000
					TOTAL		0.1626	0.1213	0.0000
					% OF ENDUSE		2.9%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.9234	-0.5832	3.8271	30	100%	0.0053			
FLUORESCENT>T8	0.4375	0.5169	1.6159	30	100%	0.0351			
EXIT SIGNS	0.0728	-0.0472	0.1601	30	100%	0.0095			
							1.6159	0.4375	0.5169
							0.1601	0.0728	-0.0472
					TOTAL	0.0328	1.7759	0.5103	0.4697
					% OF ENDUSE		10.4%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.2214	0	0.2100	15	37%	0.0963			
FREEZER STRIP CURTAIN	0.1293	0	1.5354	3	100%	0.0305			
HW HEAT RECOVERY	0.4756	0	8.7652	15	48%	0.0050			
EXHAUST HEAT RECOVERY	0.4756	0	13.2443	15	37%	0.0033			
EFFICIENT EXHAUST HOOD	3.3293	0	10.8717	15	37%	0.0280			
ECONOMIZER	1.1890	0	1.0416	15	52%	0.1043			
							1.5354	0.1293	0.0000
							4.2073	0.2283	0.0000
							4.9004	0.1760	0.0000
							4.0225	1.2318	0.0000
					TOTAL	0.0114	14.6657	1.7654	0.0000
					% OF ENDUSE		15.2%		
					GRAND TOTAL	0.0139	16.6041959	2.39697	0.4697
							14.6%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	26,052	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		GROCERY
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	ALL FUELS % SAT.	(KWH/SF)	UIC EXIST. PROTOTYPE (KWH/SF)
HEATING	7.45	55.0%	13.54	7.99
COOLING	0.04	63.0%	0.07	0.86
VENTILATION	2.30	100.0%	2.30	0.83
WATER HEAT	0.30	74.0%	0.40	1.42
REFRIGERATION	15.00	100.0%	15.00	
LIGHTING	12.75	100.0%	12.75	16.39
MISC.	10.20	99.0%	10.30	30.16
TOTAL	48.04	88.4%	54.36	57.65

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R3>R22	0.6621	0.0000	2.0888	30	55%	0.0188	1.1489	0.3642	0.0000
INSULATE WALL R5>R24	3.1208	0.0000	2.3311	30	55%	0.0795			
EFF. WINDOWS SG>DG	0.6364	0.0000	0.5663	30	55%	0.0667			
WEATHERSTRIP ACH	0.0129	0.0000	0.1381	10	55%	0.0117	0.0760	0.0071	0.0000
					TOTAL	0.0184	1.2248	0.3713	0.0000
					% OF ENDUSE		16.4%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
PARABOLIC REFLECT (SALES)	0.9742	-0.0779	3.2251	30	100%	0.0165	3.2251	0.9742	-0.0779
2 LEVEL SWITCHING	0.3147	0.0817	1.9029	15	100%	0.0190	1.9029	0.3147	0.0817
INCANDESCENT>HALOGEN	0.0048	0.0039	1.0802	1	100%	0.0084	1.0802	0.0048	0.0039
					TOTAL	0.0159	6.2082	1.2936	0.0077
					% OF ENDUSE		48.7%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
REFER CASE COVERS	0.3623	0.0000	4.2391	15	100%	0.0078	4.2391	0.3623	0.0000
REFER CASE TIMER	0.0277	0.0000	2.4183	15	100%	0.0010	2.4183	0.0277	0.0000
HW HEAT RECOVERY	0.3050	0.0000	1.4145	15	74%	0.0197	1.0467	0.2257	0.0000
HW BLANKET	0.0141	0.0000	0.0800	10	74%	0.0220	0.0592	0.0105	0.0000
REDUCE MINIMUM AIR	0.0204	0.0000	0.5286	5	55%	0.0087	0.2907	0.0112	0.0000
REFRIGERATION PUMP	0.7807	0.0000	5.0000	15	100%	0.0143	5.0000	0.7807	0.0000
FREEZER STRIP CURTAIN	0.0266	0.0000	0.2069	15	100%	0.0117	0.2069	0.0266	0.0000
RESISTANCE>HEAT PUMP	3.4290	0.0000	1.9174	15	41%	0.1633			
EXHAUST HEAT RECOVERY	0.3489	0.0000	0.8891	15	55%	0.0358	0.4890	0.1919	0.0000
					TOTAL	0.0110	13.7499	1.6367	0.0000
					% OF ENDUSE		39.0%		
					GRAND TOTAL	0.0129	21.183	3.30159	0.00768
							44.1%		

INPUT ARRAY -- COMMERCIAL BUILDINGS		
NEW	26,052	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		GROCERY
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT.	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	0.65	31.0%	2.09	2.10
COOLING	0.08	85.0%	0.09	0.10
VENTILATION	4.10	100.0%	4.10	4.10
WATER HEAT	0.20	65.0%	0.30	0.30
REFRIGERATION	43.30	100.0%	43.30	43.30
LIGHTING	14.50	100.0%	14.50	14.50
MISC.	5.20	100.0%	5.20	5.20
TOTAL	68.02	97.8%	69.59	69.60

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0068	0	0.0080	30	31%	0.0505			
INSUL ROOF R19>R30	1.6373	0.0000	1.2051	30	31%	0.0807			
LOW E WINDOWS	0.0874	0.0000	0.1660	30	31%	0.0312	0.0515	0.0271	0.0000
					TOTAL	0.0312	0.0515	0.0271	0.0000
					% OF ENDUSE		7.0%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS									
FLUORESCENT>T8	0.5385	0.6822	1.9529	30	100%	0.0371	1.9529	0.5385	0.6822
INCANDESCENT>HALOGEN	0.0075	0.0005	0.4449	1	100%	0.0186	0.4449	0.0075	0.0005
EXIT SIGNS	0.0278	-0.0384	0.0721	30	100%	-0.0087	0.0721	0.0278	-0.0384
2 LEVEL SWITCHING	0.1594	0.0118	0.6086	30	100%	0.0167	0.6086	0.1594	0.0118
					TOTAL	0.0293	3.0785	0.7332	0.6561
					% OF ENDUSE		21.2%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0192	0	0.0070	15	85%	0.2504			
DHW HEAT RECOVER	0.2911	0.0000	0.3000	15	65%	0.0886			
REFER FLOATING HEAD	0.0768	0.0000	4.7150	10	100%	0.0020	4.7150	0.0768	0.0000
REFER CASE COVERS	0.1725	0.0000	0.9520	10	100%	0.0226	0.9520	0.1725	0.0000
REFER TIMERS	0.1376	0.0000	5.2650	10	100%	0.0033	5.2650	0.1376	0.0000
MECHANICAL SUBCOOLING	0.1725	0.0000	0.9320	10	100%	0.0231	0.9320	0.1725	0.0000
HOT GAS DEFROST	0.0998	0.0000	2.4110	10	100%	0.0052	2.4110	0.0998	0.0000
REFER PUMP AFT #3	0.9485	0.0000	0.9220	10	100%	0.1282			
EFF FAN MOTORS	0.3841	0.0000	2.5890	10	100%	0.0185	2.5890	0.3841	0.0000
					TOTAL	0.0077	16.8640	1.0433	0.0000
					% OF ENDUSE		31.5%		
					GRAND TOTAL	0.0111	19.99396323	1.80359	0.65612
							29.4%		

INPUT ARRAY -- COMMERCIAL BUILDINGS		
EXISTING	272,000	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		HOSPITAL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% SAT.	ALL FUELS (KWH/SF)	UIC EXIST. PROTOTYPE (KWH/SF)
HEATING	4.26	34.0%	12.54	36.00
COOLING	0.77	82.0%	0.94	2.29
VENTILATION	3.03	100.0%	3.03	6.82
WATER HEAT	2.33	33.0%	7.07	1.80
REFRIGERATION	0.00			
LIGHTING	7.88	100.0%	7.88	8.85
MISC.	0.64	85.2%	0.75	4.69
TOTAL	18.91	58.7%	32.21	60.45

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
ROOF INSUL. R7>R23	0.1204	0.0000	0.7885	30	12%	0.0091	0.0934	0.0143	0.0000
EFF. WINDOWS SG>DG	0.9038	0.0000	0.5999	20	12%	0.1130			
					TOTAL	0.0091	0.0934	0.0143	0.0000
					% OF ENDUSE		1.9%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	0.5859	0.4080	0.6643	30	100%	0.0889			
INCANDESCENT>PL	0.0158	-0.0826	0.5838	30	100%	-0.0068	0.5838	0.0158	-0.0826
OUTSIDE LIGHTS	0.0006	-0.0103	0.0173	30	100%	-0.0335	0.0173	0.0006	-0.0103
					TOTAL	-0.0076	0.6010	0.0163	-0.0929
					% OF ENDUSE		7.6%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
TEMP RESET	0.0465	0.0000	2.3263	10	34%	0.0025	0.7909	0.0158	0.0000
AAHX	0.4145	0.0000	3.3899	15	34%	0.0112	1.1526	0.1409	0.0000
FAN MOTORS	0.0985	0.0000	0.1231	15	100%	0.0731			
VAV	2.1601	0.0000	0.4300	15	34%	0.4588			
HEAT RECOVER DHW	0.0213	0.000	3.0000	15	25%	0.0006	0.7425	0.0053	0.0000
					TOTAL	0.0057	2.6860	0.1620	0.0000
					% OF ENDUSE		24.4%		
					GRAND TOTAL	0.0034	3.3804405	0.19256	-0.0929
							17.9%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	272,000	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		HOSPITAL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT.		MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	7.27	34.0%	21.37	21.40	
COOLING	1.23	82.0%	1.50	1.50	
VENTILATION	6.00	100.0%	6.00	6.00	
WATER HEAT	0.46	33.0%	1.40	1.40	
REFRIGERATION	0.00				
LIGHTING	7.26	100.0%	6.97	8.90	
MISC.	4.43	85.2%	5.20	5.20	
TOTAL	26.65	62.8%	42.44	44.40	

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0192	0.0000	0.0320	30	34%	0.0356			
INSULATE WALLS R5>R24	0.0985	0.0000	0.0780	30	26%	0.0750			
LOW E WINDOWS	0.2124	0.0000	0.1949	30	26%	0.0647			
TOTAL							0.0000	0.0000	0.0000
% OF ENDUSE							0.0%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.1631	0.4184	1.9207	30	100%	0.0180			
FLUORESCENT>T8	0.1956	0.3226	0.7754	30	100%	0.0397	0.7754	0.1956	0.3226
INCANDESCENT>HALOGEN	0.0031	0.0016	0.2262	1	100%	0.0217	0.2262	0.0031	0.0016
EXIT SIGNS	0.0536	-0.0594	0.1346	30	100%	-0.0026	0.1346	0.0536	-0.0594
DAYLIGHT DIM AFT #2	0.0767	0.0200	0.2414	15	75%	0.0366	0.1811	0.0575	0.0150
OCCUPANCY SENSOR AFT #2	0.1109	0.0171	0.2854	10	75%	0.0559			
AMBIENT/TASK AFT #2	0.0534	0.0227	0.2360	30	75%	0.0191	0.1770	0.0401	0.0170
TOTAL						0.0319	1.4943	0.3499	0.2968
% OF ENDUSE							16.8%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
AAHX	0.4384	0.0000	3.3969	15	26%	0.0118	0.8662	0.1118	0.0000
EFFICIENT CHILLER	0.1718	0.0000	0.4390	15	62%	0.0357	0.2700	0.1056	0.0000
VAV	2.0507	0.0000	0.4300	15	26%	0.4355			
HEAT RECOVER DHW	0.5515	0.0000	0.7000	15	25%	0.0720			
EVAP COOLER	0.5616	0.0000	0.4390	15	62%	0.1168			
TOTAL						0.0175	1.1362	0.2174	0.0000
% OF ENDUSE							6.0%		
GRAND TOTAL						0.0251	2.6305388	0.567356	0.29678
							9.4%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	11,664	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		HOTEL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% SAT.	ALL FUELS (KWH/SF)	EXISTING PROTOTYPE (KWH/SF)
HEATING	4.85	58.0%	8.37	9.17
COOLING	0.64	51.0%	1.25	0.49
VENTILATION	2.23	100.0%	2.23	0.03
WATER HEAT	1.26	45.0%	2.80	6.02
REFRIGERATION	0.00	100.0%		
LIGHTING	4.74	100.0%	4.74	3.72
MISC.	1.03	67.7%	1.52	1.94
TOTAL	14.75	70.5%	20.91	21.37

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
ROOF INSUL. R7>R27	0.2547	0.0000	0.7509	30	58%	0.0201	0.4355	0.1477	0.0000
WALL INSUL. R2>R11	0.2653	0.0000	3.5652	30	58%	0.0044	2.0678	0.1539	0.0000
WINDOW SG>DG	0.2102	0.0000	0.9382	20	58%	0.0168	0.5441	0.1219	0.0000
					TOTAL	0.0089	3.0475	0.4235	0.0000
					% OF ENDUSE		55.5%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INCANDESCENT>PL	1.7704	-1.0615	0.4177	15	100%	0.1550	0.4607	0.1204	0.0106
FLUORESCENT>T8	0.1204	0.0106	0.4607	15	100%	0.0260	0.1740	0.0793	0.0113
EXTERNAL>HPS	0.0793	0.0113	0.1740	15	100%	0.0476			
					TOTAL	0.0260	0.6347	0.1997	0.0219
					% OF ENDUSE		13.4%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
EFFICIENT THERMOSTAT	0.2915	0.0000	1.1130	15	44%	0.0239	0.4842	0.1268	0.0000
LOW FLOW SHOWER	0.0450	-0.2112	2.1652	10	38%	-0.0096	0.8282	0.0172	-0.0808
DHW & PIPE INSULATION	0.0257	0.0000	0.6331	10	38%	0.0051	0.2421	0.0098	0.0000
					TOTAL	0.0031	1.5545	0.1539	-0.0808
					% OF ENDUSE		15.5%		
					GRAND TOTAL	0.0087	5.236715081	0.77702	-0.0589
							35.5%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	11,664	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		HOTEL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT.	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	2.48	58.0%	4.23	4.55
COOLING	0.25	51.0%	0.49	0.50
VENTILATION	0.02	100.0%	0.02	0.02
WATER HEAT	2.71	45.0%	6.03	6.03
COOKING	0.00	100.0%		
LIGHTING	3.43	100.0%	3.40	3.63
MISC.	1.31	67.7%	1.94	1.94
TOTAL	10.21	70.5%	16.11	16.67

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT CODE>MCS	0.1948	0.0000	0.3091	30	58%	0.0374			
LOW E WINDOW U65>U39	0.2407	0.0000	0.6371	30	58%	0.0224	0.3695	0.1396	0.0000
INSULATE ROOF R19>R38	0.1767	0.0000	0.2826	30	58%	0.0371	0.1639	0.1025	0.0000
INSULATE WALL R19>R24	0.3543	0.0000	0.5637	20	58%	0.0471	0.3269	0.2055	0.0000
					TOTAL	0.0269	0.8604	0.4475	0.0000
					% OF ENDUSE		29.7%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT CODE>MCS	0.6541	-0.5184	0.2258	30	100%	0.0357			
INCANDESCENT>PL	0.6541	-0.5184	0.2258	30	100%	0.0357	0.2258	0.6541	-0.5184
HPS EXTERIOR LIGHTS	0.1740	-0.0148	0.1740	30	100%	0.0543	0.1740	0.1740	-0.0148
					TOTAL	0.0357	0.3998	0.8281	-0.5332
					% OF ENDUSE		11.0%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
LOW FLOW SHOWER	0.0450	-0.2112	2.1652	10	36%	-0.0096	0.7795	0.0162	-0.0760
DHW & PIPE INSULATION	0.0257	0.0000	0.6331	10	36%	0.0051	0.2279	0.0093	0.0000
					TOTAL	-0.0063	1.0074	0.0255	-0.0760
					% OF ENDUSE		12.4%		
					GRAND TOTAL	0.0091	2.267484276	1.301097394	-0.6093
							19.3%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	408,000	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		LG OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE	ELEC(kWh/SF)	ALL FUELS % SAT.	UIC EXIST. (KWH/SF)	PROTOTYPE (KWH/SF)	(KWH/SF)
HEATING	4.19	29.4%	14.25	14.16	
COOLING	1.46	100.0%	1.46	1.70	
VENTILATION	4.30	100.0%	4.30	5.34	
WATER HEAT	0.82	75.2%	1.09	0.20	
REFRIGERATION	0.00				
LIGHTING	6.56	100.0%	6.56	10.50	
MISC.	0.35	85.5%	0.41	3.12	
TOTAL	17.68	62.6%	28.07	35.02	

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSUL. ROOF R6>R24	0.0263	0.0000	0.1044	30	22%	0.0149	0.0230	0.0058	0.0000
W1 WINDOW SG>DG	0.0173	0.0000	0.0191	30	22%	0.0539	0.0042	0.0038	0.0000
W2 LOW E. WINDOWS AFT W1	0.0040	0.0000	0.0056	30	22%	0.0426	0.0012	0.0009	0.0000
					TOTAL	0.0163	0.0285	0.0105	0.0000
					% OF ENDUSE		0.5%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
40W FLUORESCENT>T8	1.4529	0.1440	2.0306	15	100%	0.0718			
INCANDESCENT>PL	0.1650	-0.4151	0.4118	3	100%	-0.2198	0.4118	0.1650	-0.4151
EXIT SIGNS	0.1097	-0.0709	0.1705	30	100%	0.0135	0.1705	0.1097	-0.0709
OCCUPANCY SENSOR AFT #1	0.2246	0.0159	0.9480	10	75%	0.0316	0.7110	0.1685	0.0120
AMBIENT/TASK AFT #4	0.4938	0.1317	0.9125	30	75%	0.0407	0.6844	0.3703	0.0988
DAYLIGHT DIM AFT #5	0.2822	0.0059	0.2539	15	75%	0.1036			
					TOTAL	-0.0191	1.9777	0.8135	-0.3752
					% OF ENDUSE		30.1%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
TEMP RESET FOR MULTIZONE	0.0148	0.0000	0.0176	15	29%	0.0764			
EFF FANS	0.1115	0.0000	0.0089	15	100%	1.1435			
TUNE & ADJUST	0.0124	0.0000	0.0177	5	29%	0.1581			
TRAV RETROFIT	1.8382	-1.2973	3.9798	30	100%	0.0081	3.9798	1.8382	-1.2973
EFF CHILLER AT CHANGEOUT	0.1416	0.0000	0.0010	15	75%	12.7793			
					TOTAL	0.0081	3.9798	1.8382	-1.2973
					% OF ENDUSE		35.8%		
					GRAND TOTAL	-0.0009	5.9859799994	2.66223	-1.6726
							33.9%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	408,000	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		LG OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELECT(kWh/SF)	% SAT.	MCS (KWH/SF)	PRACTICE (KWH/SF)
HEATING	1.48	29.4%	4.99	5.30
COOLING	0.60	100.0%	0.60	0.60
VENTILATION	1.80	100.0%	1.80	1.80
WATER HEAT	0.15	75.2%	0.20	0.20
REFRIGERATION	0.00			
LIGHTING	6.54	100.0%	6.33	7.70
MISC.	3.08	85.5%	3.60	3.60
TOTAL	13.65	62.6%	17.52	19.20

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0559	0	0.3340	25	29.4%	0.0110	0.0982	0.0164	0.0000
LOW E. WINDOWS	0.7124	0	0.5269	20	29.4%	0.1014			
					TOTAL	0.0110	0.0982	0.0164	0.0000
					% OF ENDUSE		4.5%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.2620	-0.0978	1.3673	30	100.00%	0.0071	1.3673	0.2620	-0.0978
REDUCE LIGHT LEVEL	0.0829	0.0867	0.4905	30	100.00%	0.0205	0.4905	0.0829	0.0867
EXIT SIGNS	0.0537	-0.0742	0.1725	30	100.00%	-0.0071	0.1725	0.0537	-0.0742
OCCUPANCY SENSOR AFTER #2	0.2246	0.0081	1.1045	10	100.00%	0.0263	1.1045	0.2246	0.0081
AMBIENT/TASK AFTER #4	0.4938	0.1153	1.0178	30	100.00%	0.0355	1.0178	0.4938	0.1153
DAYLIGHT DIM AFTER #5	0.2822	0.0029	0.4166	15	100.00%	0.0625			
					TOTAL	0.0202	4.1527	1.1170	0.0382
					% OF ENDUSE		53.9%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0010	0	0.0011	15	100.00%	0.0875			
VSD MOTORS	0.0459	0	0.0922	15	100%	0.0454	0.0922	0.0459	0.0000
TRAV CONTROLS	1.8382	-0.4540	1.5468	30	100%	0.0531	1.5468	1.8382	-0.4540
					TOTAL		1.6391	1.8841	-0.4540
					% OF ENDUSE		37.9%		
					GRAND TOTAL	0.0200	5.8899361473	3.01758	-0.4159
							49.0%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	4,880	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELECT(kWh/SF)	% S(KWH/SF)	MCS	PRACTICE (KWH/SF)
HEATING	2.94	42.0%	7.00	7.18
COOLING	1.10	58.0%	1.89	1.98
VENTILATION	1.14	100.0%	1.14	1.14
WATER HEAT	0.36	66.0%	0.54	0.54
REFRIGERATION	0.00			
LIGHTING	7.45	100.0%	7.45	7.00
MISC.	0.43	85.5%	0.50	0.50
TOTAL	13.42	72.5%	18.52	18.34

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R4>R24	0.3312	0	1.2518	25	42.0%	0.0173	0.5258	0.1391	0.0000
INSUL. WALL R5>R24	6.4168	0	2.1645	25	42.0%	0.1942			
WINDOWS SG>DG	1.4499	0	1.5990	25	42.0%	0.0594			
LOW E. WINDOWS	1.0529	0	0.4689	20	42.0%	0.1685			
SOLAR FILM	0.5895	0	0.5357	15	58.0%	0.1005			
					TOTAL	0.0173	0.5258	0.1391	0.0000
					% OF ENDUSE		13.0%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	1.0209	0.2350	1.6221	30	100.00%	0.0460	1.6221	1.0209	0.2350
EXIT SIGNS	0.0496	-0.0531	0.1426	30	100.00%	-0.0015	0.1426	0.0496	-0.0531
INCAND. FLOOD > HALOGEN	0.0038	0.0017	0.0854	1	100.00%	0.0678			
DAYLIGHT DIM AFT #1	0.5570	0.1362	1.1766	30	100.00%	0.0350	1.1766	0.5570	0.1362
OCCUPANCY SENSOR AFT #1	0.2809	0.0164	0.1416	30	100.00%	0.1247			
AMBIENT/TASK AFT #1	0.9910	0.1997	1.0673	30	100.00%	0.0663			
					TOTAL	0.0393	2.9412	1.6275	0.3180
					% OF ENDUSE		39.5%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
ECONOMIZER	0.4262	0	0.6629	15	58.00%	0.0587			
OPTIMUM START TIMER	0.3084	0	0.6873	15	31.50%	0.0410	0.2165	0.0971	0.0000
AAHX	1.0362	0	1.0680	15	31.50%	0.0886			
REDUCE OUTSIDE AIR	0.0130	0	1.0348	15	31.50%	0.0012	0.3260	0.0041	0.0000
RESISTANCE>HEAT PUMP	3.0502	0	4.8840	15	53.00%	0.0570			
EFF HEAT PUMP	1.0362	0	0.5154	15	17.00%	0.1836			
					TOTAL	0.0170	0.5425	0.1013	0.0000
					% OF ENDUSE		9.1%		
					GRAND TOTAL	0.0334	4.0094641115	1.867795	0.31804
							29.9%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	4,880	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELECT(kWh/SF)	% S(KWH/SF)	MCS	PRACTICE (KWH/SF)
HEATING	2.95	42.0%	7.00	7.18
COOLING	1.10	58.0%	1.89	1.98
VENTILATION	1.14	100.0%	1.14	1.14
WATER HEAT	0.36	66.0%	0.54	0.54
REFRIGERATION	0.00			
LIGHTING	7.24	100.0%	7.28	7.00
MISC.	0.43	85.5%	0.50	0.50
TOTAL	13.21	72.0%	18.35	18.34

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0322	0	0.1830	25	42.0%	0.0115			
INSUL. WALL R11>R16	0.3842	0	0.8710	25	42.0%	0.0289	0.3658	0.1614	0.0000
INSULATE ROOF R13>R30	0.1643	0	0.2757	25	42.0%	0.0391	0.1158	0.0690	0.0000
INSULATE ROOF R30>R38	0.0775	0	0.0546	25	42.0%	0.0930			
LOW E. WINDOWS	1.0529	0	1.0068	20	100.0%	0.0785			
					TOTAL	0.0313	0.4816	0.2304	0.0000
					% OF ENDUSE		11.6%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.3959	0.0204	1.2889	30	100.00%	0.0192			
REDUCE LIGHT LEVEL	0.1693	0.1167	0.4591	30	100.00%	0.0370	0.4591	0.1693	0.1167
EXIT SIGNS	0.0496	-0.0573	0.1488	30	100.00%	-0.0031	0.1488	0.0496	-0.0573
DAYLIGHT DIM AFT #1	0.5570	0.1015	1.2277	30	100.00%	0.0319	1.2277	0.5570	0.1015
OCCUPANCY SENSOR AFT #1	0.2809	0.0122	0.1478	30	100.00%	0.1178			
AMBIENT/TASK AFT #1	0.9910	0.1683	1.1136	30	100.00%	0.0618			
					TOTAL	0.0303	1.8355	0.7758	0.1608
					% OF ENDUSE		26.2%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0852	0	0.0889	15	100.00%	0.0875			
ECONOMIZER	0.4262	0	0.6629	15	58.00%	0.0587			
OPTIMUM START TIMER	0.3084	0	0.6873	15	31.50%	0.0410	0.2165	0.0971	0.0000
AAHX	1.0362	0	1.0680	15	31.50%	0.0886			
REDUCE OUTSIDE AIR	0.0130	0	1.0348	15	31.50%	0.0012	0.3260	0.0041	0.0000
EFF HEAT PUMP	1.0362	0	0.5154	15	17.00%	0.1836			
					TOTAL	0.0170	0.5425	0.1013	0.0000
					% OF ENDUSE		8.7%		
					GRAND TOTAL	0.0280	2.8596021221	1.10747	0.16082
							21.6%		

INPUT ARRAY -- COMMERCIAL BUILDINGS		
EXISTING	13,125	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		RETAIL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	EUI(kWh/SF)	% SAT. (KWH/SF)	ALL FUELS (KWH/SF)	UIC PROTOTYPE
HEATING	5.14	35.60%	14.45	4.79
COOLING	1.43	63.00%	2.27	0.90
VENTILATION	5.88	100.00%	5.88	1.00
WATER HEAT	0.09	74.00%	0.12	0.42
REFRIGERATION	0.00			
LIGHTING	6.71	100.00%	6.71	8.62
MISC.	0.61	95.20%	0.64	1.14
TOTAL	19.86	66.05%	30.07	16.87

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R7>R20	0.6621	0.0000	2.6233	30	27%	0.0150	0.7004	0.1768	0.0000
INSULATE WALL R3>R22	2.6309	0.0000	1.2182	30	27%	0.1283			
LOW E. WINDOWS	0.5731	0.0000	0.5581	30	27%	0.0610			
WEATHERSTRIP ACH	0.0123	0.0000	0.0040	10	27%	0.3811			
					TOTAL	0.0150	0.7004	0.1768	0.0000
					% OF ENDUSE		10.7%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	0.6212	0.2863	2.2735	30	100%	0.0237	2.2735	0.6212	0.2863
INCANDESCENT>HALOGEN	0.0040	0.0387	0.8825	1	100%	0.0504	0.8825	0.0040	0.0387
DAYLIGHT DIM AFT #1	0.0678	0.0546	0.8230	30	100%	0.0088	0.8230	0.0678	0.0546
EXIT SIGNS	0.0352	0.0144	0.0336	30	100%	0.0877			
					TOTAL	0.0198	3.9790	0.6930	0.3797
					% OF ENDUSE		59.3%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
AAHX	0.6604	0.0000	0.5739	14.0	27%	0.1105			
RESISTANCE > HEAT PUMP	3.5315	0.0000	2.8524	15.0	5%	0.1131			
DHW BLANKET	0.0046	0.0000	0.0315	10.0	56%	0.0181	0.0175	0.0025	0.0000
					TOTAL	0.0181	0.0175	0.0025	0.0000
					% OF ENDUSE		0.1%		
					GRAND TOTAL	0.0189	4.6969138469	0.87232	0.37968
							23.7%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	13,124	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		RETAIL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	MCS(kWh/SF)	% SAT.	MCS PROTOTYPE (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	0.27	35.60%	0.70	1.10
COOLING	0.41	63.00%	0.65	0.70
VENTILATION	1.60	100.00%	1.60	1.60
WATER HEAT	0.03	74.00%	0.04	0.04
REFRIGERATION	0.00			
LIGHTING	8.93	100.00%	8.88	9.20
MISC.	0.94	85.20%	1.10	1.10
TOTAL	12.18	68.50%	12.97	13.74

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT CODE>MCS	0.1629	0	0.3970	30	36%	0.0244			
DG > LOW E WINDOWS	0.0787	0.0000	0.1174	20	36%	0.0503	0.0418	0.0280	0.0000
					TOTAL		0.0418	0.0280	0.0000
					% OF ENDUSE		5.0%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT CODE>MCS	0.0575	-1.7760	0.3233	30	100%	-0.3157			
FLUORESCENT>T8	0.4300	0.4772	1.9613	30	100%	0.0275	1.9613	0.4300	0.4772
INCANDESCENT>HALOGEN	0.0094	-0.0194	1.0110	1	100%	-0.0103	1.0110	0.0094	-0.0194
DAYLIGHT DIM AFT #1	0.0678	0.0223	0.6903	15	100%	0.0119	0.6903	0.0678	0.0223
EXIT SIGNS	0.0245	0.0042	0.0829	30	100%	0.0206	0.0829	0.0245	0.0042
					TOTAL	0.0143	3.7454	0.5318	0.4843
					% OF ENDUSE		40.7%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0698	0.0000	0.0500	15	36%	0.1275			
AAHX	0.6605	0.0000	0.5162	15	27%	0.1169			
EFF HEAT PUMP UPGRADE	0.7568	0.0000	0.1978	15	7%	0.3494			
RADIANT HEATERS (STORAGE)	0.0358	0.0000	0.0754	15	27%	0.0434	0.0201	0.0096	0.0000
					TOTAL	0.0434	0.0201	0.0096	0.0000
					% OF ENDUSE		9.5%		
					GRAND TOTAL	0.0144	3.80739172566	0.56935	0.48426
							40.5%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	67,784	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		SCHOOL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT	ALL FUELS (KWH/SF)	UIC PROTOTYPE (KWH/SF)
HEATING	3.65	20.0%	18.24	15.45
COOLING	0.03	42.0%	0.07	0.00
VENTILATION	1.46	100.0%	1.46	1.09
WATER HEAT	0.15	59.0%	0.25	0.55
REFRIGERATION	0.00			
LIGHTING	4.72	100.0%	4.72	3.92
MISC.	0.50	88.5%	0.56	0.92
TOTAL	10.51	41.5%	25.30	21.93

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R7> R27	0.602	0.000	2.2842	30	20%	0.0157	0.4568	0.1204	0.0000
LOW E WINDOWS	1.875	0.000	2.0334	20	20%	0.0692			
INSULATE WALLS R4>R23	3.276	0.000	1.9553	30	20%	0.0995			
WEATHERSTRIP ACH	0.267	0.000	2.3545	10	20%	0.0141	0.4709	0.0534	0.0000
					TOTAL	0.0149	0.9277	0.1738	0.0000
					% OF ENDUSE		25.2%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	0.7753	0.1869	1.5359	30	100%	0.0372	1.5359	0.7753	0.1869
INCANDESCENT>PL	0.2128	-0.1546	0.3955	15	100%	0.0135	0.3955	0.2128	-0.1546
EXIT SIGNS	0.1072	-0.0824	0.1327	30	100%	0.0111	0.1327	0.1072	-0.0824
DAYLIGHT DIM AFT #1	0.0987	0.0058	0.1039	15	100%	0.0919			
OCCUPANCY SENSOR AFT #1	0.2438	0.0289	0.5213	15	100%	0.0478	0.5213	0.2438	0.0289
					TOTAL	0.0310	2.5854	1.3392	-0.0212
					% OF ENDUSE		54.8%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
ADJUST OUTSIDE AIR	0.033	0.000	1.9237	5.0	20%	0.0039	0.3847	0.0066	0.0000
DHW BLANKET	0.005	0.000	0.0680	10.0	44%	0.0100	0.0301	0.0024	0.0000
					TOTAL	0.0043	0.4148	0.0090	0.0000
					% OF ENDUSE		7.2%		
					GRAND TOTAL	0.0233	3.92798745574	1.52193	-0.0212
							37.4%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	277,200	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		SCHOOL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SA	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	1.80	20.00%	8.98	9.10
COOLING	0.00	42.00%	0.00	0.00
VENTILATION	2.21	100.00%	2.22	2.20
WATER HEAT	0.89	59.00%	1.50	1.50
REFRIGERATION	0.00			
LIGHTING	4.54	100.00%	4.43	5.20
MISC.	1.15	88.50%	1.30	1.30
TOTAL	10.59	57.50%	18.42	19.30

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0026	0.0000	0.0298	30	20%	0.0051			
INSULATE ROOF R19> R38	0.0728	0.0000	0.1319	30	20%	0.0328	0.0264	0.0146	0.0000
INSULATE WALLS R6>R19	0.0587	0.0000	0.1185	30	20%	0.0294	0.0237	0.0117	0.0000
INSULATE WALLS>R24 AFT #3	0.0014	0	0.0013	25	20.0%	0.0705			
LOW E WINDOWS	0.0728	0.0000	0.0703	30	20%	0.0615			
					TOTAL	0.0312	0.0501	0.0263	0.0000
					% OF ENDUSE		2.8%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0341	-0.0298	0.1780	30	100%	0.0014			
FLUORESCENT>T8	0.1438	0.1160	0.2141	30	100%	0.0721			
EXIT SIGNS	0.0131	-0.0188	0.0333	30	100%	-0.0102	0.0333	0.0131	-0.0188
DAYLIGHT DIM AFT #1	0.0241	0.0000	0.0211	15	100%	0.1046			
OCCUPANCY SENSOR AFT #1	0.0596	0.0000	0.1020	10	100%	0.0729			
					TOTAL	-0.0102	0.0333	0.0131	-0.0188
					% OF ENDUSE		0.6%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0006	0.0000	0.0000	15	20%	1.2294			
VSD MOTORS	0.0225	0.0000	0.0577	15	75%	0.0356	0.0433	0.0169	0.0000
EMCS CONTROLS	0.2755	0.0321	0.2388	15	20%	0.1176			
					TOTAL	0.0356	0.0433	0.0169	0.0000
					% OF ENDUSE		0.7%		
					GRAND TOTAL	0.0218	0.12663059235	0.05626	-0.0188
							1.1%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	18,025	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		WAREHOUSE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% SAT.(KWH/	ALL FUELS (KWH/SF)	UIC EXIST. PROTOTYPE
HEATING	2.72	38.0%	7.16	6.33
COOLING	0.04	52.0%	0.07	0.22
VENTILATION	0.03	100.0%	0.03	0.19
WATER HEAT	0.01	62.0%	0.02	0.15
REFRIGERATION	5.00	100.0%	5.00	
LIGHTING	3.29	100.0%	3.29	3.50
MISC.	3.02	97.6%	3.09	1.72
TOTAL	14.11	75.6%	18.66	12.11

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATED ROOF R2>R20	0.6015	0.000	2.5987	30	38%	0.0137	0.9875	0.2286	0.0000
INSULATED WALL R2>R20	2.0340	0.000	1.8849	30	38%	0.0641			
LOW E WINDOWS SG>DG	0.4889	0.000	0.2900	20	38%	0.1265			
WEATHERSTRIP ACH	0.0433	0.000	0.1460	10	38%	0.0370	0.0555	0.0164	0.0000
					TOTAL	0.0150	1.0430	0.2450	0.0000
					% OF ENDUSE		37.8%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
OFFICE FLUORESCENT>T8	0.1369	0.032	0.2710	25	100%	0.0408	0.2710	0.1369	0.0319
STORAGE DELAMP	0.1363	-0.018	0.2710	25	100%	0.0286	0.2710	0.1363	-0.0181
INCANDESCENT>HALOGEN, HID	0.0054	-0.001	0.3331	1	100%	0.0127	0.3331	0.0054	-0.0013
					TOTAL	0.0347	0.8751	0.2786	0.0125
					% OF ENDUSE		26.6%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
REDUCE OUTSIDE AIR	0.0051	0.000	0.1283	5	38%	0.0091	0.0487	0.0020	0.0000
TEMP SETBACK	0.0902	0.000	1.4371	10	38%	0.0078	0.5461	0.0343	0.0000
RADIANT HEATERS	1.0787	0.000	2.4596	15	38%	0.0401	0.9346	0.4099	0.0000
AAHX	0.2405	0.000	0.1218	15	38%	0.1803			
RESIST> HP (OFFICE)	0.4675	0.000	0.6382	15	20%	0.0669			
EFFICIENT REFER.	0.7772	0.000	3.5000	15	38%	0.0203	1.3300	0.2953	0.0000
DESTRATIFIERS	0.1703	0.000	1.5504	15	38%	0.0100	0.5892	0.0647	0.0000
DHW BLANKET	0.0035	0.000	0.0229	10	47%	0.0192	0.0107	0.0016	0.0000
ECONOMIZER (OFFICE)	0.0835	0.000	0.0798	15	39%	0.0955			
					TOTAL	0.0217	3.4593	0.8078	0.0000
					% OF ENDUSE		32.0%		
					GRAND TOTAL	0.0217	5.37742092649	1.33144	0.01254
							38.1%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	18,025	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		WAREHOUSE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	0.37	38.0%	0.93	1.20
COOLING	0.10	52.0%	0.19	0.20
VENTILATION	0.30	100.0%	0.30	0.30
WATER HEAT	0.12	62.0%	0.20	0.20
REFRIGERATION	4.00	100.0%	4.00	4.00
LIGHTING	2.28	100.0%	2.10	3.30
MISC.	1.17	97.6%	1.20	1.20
TOTAL	8.34	93.6%	8.91	10.40

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.1197	0	0.2700	30	38%	0.0263			
INSULATED WALL R11>R16	0.2249	0.000	0.1328	30	38%	0.1006			
INSULATED WALL R11>R24	0.0445	0	0.0985	25	38%	0.0296	0.0374	0.0169	0.0000
LOW E WINDOWS	0.1351	0.000	0.0627	30	38%	0.1281			
INSULATE ROOF>R30	0.3400	0.000	0.0940	30	38%	0.2149			
					TOTAL	0.0296	0.0374	0.0169	0.0000
					% OF ENDUSE		6.7%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	-0.0156	-0.1911	1.2014	30	100%	-0.0102			
EXIT SIGNS	0.0268	0.0093	0.0775	30	100%	0.0277	0.0775	0.0268	0.0093
AMBIENT/TASK LIGHT AFT #1	0.0683	0.0109	0.2469	30	100%	0.0191	0.2469	0.0683	0.0109
DAYLIGHT DIM AFT #1	0.0692	0.0050	0.1509	15	100%	0.0449	0.1509	0.0692	0.0050
OCCUPANCY SENSOR AFT #1	0.0421	0.0136	0.5677	10	100%	0.0122	0.5677	0.0421	0.0136
					TOTAL	0.0155	1.0430	0.2063	0.0389
					% OF ENDUSE		31.6%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0139	0	0.0140	15	38%	0.0906			
EFFICIENT REFER.	0.6670	0.000	3.5000	15	75%	0.0174	2.6250	0.5003	0.0000
ECONOMIZER	0.0577	0.000	0.0920	15	39%	0.0573			
					TOTAL	0.0174	2.6250	0.5003	0.0000
					% OF ENDUSE		40.8%		
					GRAND TOTAL	0.0170	3.70543553398	0.7235	0.03885
							38.1%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	2,624	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		FAST FOOD
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% SAKWH/SF)	ALL FUELS	UIC PROTOTYPE (KWH/SF)
HEATING	8.05	26.2%	30.71	32.64
COOLING	1.12	84.7%	1.32	9.24
VENTILATION	8.60	100.0%	8.60	6.42
WATER HEAT	0.69	20.0%	3.43	8.76
REFRIGERATION	3.00	100.0%	3.00	
LIGHTING	8.79	100.0%	8.79	17.60
MISC.	1.05	30.0%	3.49	55.82
TOTAL	31.30	52.7%	59.34	130.48

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R6>R26	0.6450	0.0000	3.7606	30	26%	0.0102	0.9853	0.1690	0.0000
INSULATE WALL R7>R19	6.8359	0.0000	4.6354	30	26%	0.0876			
EFF. WINDOWS SG>LOW E	2.6969	0.0000	2.3300	30	26%	0.0687			
SOLAR FILM	0.3514	0.0000	1.6284	7	85%	0.0362	1.3793	0.2976	0.0000
					TOTAL	0.0102	2.3646	0.4666	0.0000
					% OF ENDUSE		25.8%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	1.1378	0.3401	1.6545	15	100%	0.0816			
INCANDESCENT>PL	0.7954	-0.1937	1.8022	15	100%	0.0305	1.8022	0.7954	-0.1937
					TOTAL	0.0305	1.8022	0.7954	-0.1937
					% OF ENDUSE		20.5%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
AAHX (DINING RM)	0.5506	0.0000	1.2754	15	26%	0.0394	0.3342	0.1443	0.0000
EFFICIENT EXHAUST HOOD	7.7081	0.0000	18.1475	15	26%	0.0388	4.7546	2.0195	0.0000
HEAT PUMP (DINING RM)	6.4234	0.0000	4.0661	15	26%	0.1443			
HW HEAT RECOVERY	1.8856	0.0000	8.7652	15	8%	0.0196	0.6864	0.1477	0.0000
HW BLANKET	0.0243	0.0000	0.0469	10	8%	0.0645			
HW TIME CLOCK	0.0265	0.0000	0.0202	20	8%	0.0983			
FREEZER STRIP CURTAIN	0.1293	0.0000	1.5812	3	100%	0.0296	1.5812	0.1293	0.0000
ECONOMIZER	2.2950	0.0000	1.3251	15	85%	0.1582			
					TOTAL	0.0366	7.3564	2.4407	0.0000
					% OF ENDUSE		32.7%		
					GRAND TOTAL	0.0322	11.5231134	3.7027	-0.194
							36.8%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	2,624	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		FAST FOOD
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	4.95	26.2%	18.78	18.90
COOLING	4.49	84.7%	4.97	5.30
VENTILATION	11.00	100.0%	11.00	11.00
WATER HEAT	1.76	20.0%	8.80	8.80
REFRIGERATION	15.10	100.0%	15.10	15.10
LIGHTING	17.10	100.0%	14.49	17.10
MISC.	53.23	92.9%	6.50	57.30
TOTAL	107.63	135.1%	79.64	133.50

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0213	0.0000	0.1200	70	26%	0.0079	0.0315	0.0056	0.0000
INSUL. ROOF R19>R30	0.2890	0.0000	0.3607	30	26%	0.0476	0.0945	0.0757	0.0000
SOLAR FILM	0.3701	0.0000	1.0940	7	85%	0.0568			
WINDOWS LOW E	0.3176	0.0000	0.5741	20	26%	0.0415	0.1504	0.0832	0.0000
					TOTAL	0.0357	0.2764	0.1645	0.0000
					% OF ENDUSE		2.9%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.9234	-0.2422	2.6624	30	100%	0.0152	2.6624	0.9234	-0.2422
FLUORESCENT>T8	0.4375	0.6719	1.1946	30	100%	0.0551			
EXIT SIGNS	0.0728	-0.0320	0.1646	30	100%	0.0147	0.1646	0.0728	-0.0320
					TOTAL	0.0152	2.8271	0.9962	-0.2742
					% OF ENDUSE		16.5%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.2214	0	0.3312	15	26%	0.0611			
FREEZER STRIP CURTAIN	0.1293	0	1.5354	3	100%	0.0305	1.5354	0.1293	0.0000
HW HEAT RECOVERY	0.4756	0	8.7652	15	10%	0.0050	0.8765	0.0476	0.0000
EXHAUST HEAT RECOVERY	8.5610	0	18.1098	15	10%	0.0432	1.8110	0.8561	0.0000
EFFICIENT EXAUST HOOD	3.3293	0	16.8480	15	26%	.0.0180	4.4142	0.8723	0.0000
ECONOMIZER	1.1890	0	0.6608	15	85%	0.1643			
					TOTAL	0.0228	8.6371	1.9052	0.0000
					% OF ENDUSE		5.3%		
					GRAND TOTAL	0.0209	11.74057047	3.0659	-0.274
							6.5%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	26,052	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		GROCERY
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	ELECT.	ALL FUELS (KWH/SF)	UIC EXIST. PROTOTYPE (KWH/SF)
HEATING	2.06	15.2%	13.54	8.78
COOLING	0.05	70.0%	0.07	2.30
VENTILATION	2.30	100.0%	2.30	0.83
WATER HEAT	0.25	61.3%	0.40	1.42
REFRIGERATION	15.00	100.0%	15.00	
LIGHTING	12.75	100.0%	12.75	16.39
MISC.	10.20	99.0%	10.30	30.16
TOTAL	42.61	78.4%	54.36	59.88

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R3>R22	0.6621	0.0000	2.2977	30	15%	0.0171	0.3493	0.1006	0.0000
INSULATE WALL R5>R24	3.1208	0.0000	2.5642	30	15%	0.0723			
EFF. WINDOWS SG>DG	0.6364	0.0000	0.6229	30	15%	0.0607			
WEATHERSTRIP ACH	0.0129	0.0000	0.1519	10	15%	0.0106	0.0231	0.0020	0.0000
					TOTAL	0.0167	0.3723	0.1026	0.0000
					% OF ENDUSE	17.6%			

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
PARABOLIC REFLECT (SALES)	0.9742	0.1330	3.2251	30	100%	0.0204	3.2251	0.9742	0.1330
2 LEVEL SWITCHING	0.3147	0.1589	1.9029	15	100%	0.0227	1.9029	0.3147	0.1589
INCANDESCENT>HALOGEN	0.0048	0.0076	.1.0802	1	100%	0.0120	1.0802	0.0048	0.0076
					TOTAL	0.0213	6.2082	1.2936	0.2996
					% OF ENDUSE	48.7%			

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
REFER CASE COVERS	0.3623	0.0000	4.2391	15	100%	0.0078	4.2391	0.3623	0.0000
REFER CASE TIMER	0.0277	0.0000	2.4183	15	100%	0.0010	2.4183	0.0277	0.0000
HW HEAT RECOVERY	0.3050	0.0000	1.4145	15	61%	0.0197	0.8671	0.1870	0.0000
HW BLANKET	0.0141	0.0000	0.0800	10	61%	0.0220	0.0490	0.0087	0.0000
REDUCE MINIMUM AIR	0.0204	0.0000	0.5815	5	15%	0.0079	0.0884	0.0031	0.0000
REFRIGERATION PUMP	0.7807	0.0000	5.0000	15	100%	0.0143	5.0000	0.7807	0.0000
FREEZER STRIP CURTAIN	0.0266	0.0000	0.2069	15	100%	0.0117	0.2069	0.0266	0.0000
RESISTANCE>HEAT PUMP	3.4290	0.0000	1.9174	15	11%	0.1633			
EXHAUST HEAT RECOVERY	0.3489	0.0000	0.9781	15	15%	0.0326	0.1487	0.0530	0.0000
					TOTAL	0.0102	13.0174	1.4492	0.0000
					% OF ENDUSE	43.6%			
					GRAND TOTAL	0.0134	19.598024574	2.84542	0.29955
							46.0%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	26,052	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		GROCERY
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% S	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	0.33	15.2%	2.19	2.20
COOLING	0.21	70.0%	0.28	0.30
VENTILATION	4.20	100.0%	4.20	4.20
WATER HEAT	0.18	61.3%	0.30	0.30
REFRIGERATION	42.90	100.0%	42.90	42.90
LIGHTING	14.50	100.0%	14.50	14.50
MISC.	5.20	100.0%	5.20	5.20
TOTAL	67.53	97.1%	69.57	69.60

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0068	0	0.0080	30	15%	0.0505	0.0012	0.0010	0.0000
INSUL ROOF R19>R30	1.6373	0.0000	1.3256	30	15%	0.0734			
LOW E WINDOWS	0.0874	0.0000	0.1826	30	15%	0.0284	0.0278	0.0133	0.0000
					TOTAL	0.0284	0.0290	0.0143	0.0000
					% OF ENDUSE		5.3%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.5385	0.6846	2.1208	30	100%	0.0342	2.1208	0.5385	0.6846
FLUORESCENT>T8	0.0075	0.0006	0.4832	1	100%	0.0174	0.4832	0.0075	0.0006
INCANDESCENT>HALOGEN	0.0278	-0.0380	0.0783	30	100%	-0.0078	0.0783	0.0278	-0.0380
EXIT SIGNS	0.1594	0.0152	0.6610	30	100%	0.0157	0.6610	0.1594	0.0152
2 LEVEL SWITCHING									
					TOTAL	0.0288	3.3433	0.7332	0.6624
					% OF ENDUSE		23.1%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0192	0	0.0070	15	70%	0.2504			
DHW HEAT RECOVER	0.2911	0.0000	0.3000	15	61%	0.0886			
REFER FLOATING HEAD	0.0768	0.0000	4.7150	10	100%	0.0020	4.7150	0.0768	0.0000
REFER CASE COVERS	0.1725	0.0000	0.9520	10	100%	0.0226	0.9520	0.1725	0.0000
REFER TIMERS	0.1376	0.0000	5.2650	10	100%	0.0033	5.2650	0.1376	0.0000
MECHANICAL SUBCOOLING	0.1725	0.0000	0.9320	10	100%	0.0231	0.9320	0.1725	0.0000
HOT GAS DEFROST	0.0998	0.0000	2.4110	10	100%	0.0052	2.4110	0.0998	0.0000
REFER PUMP AFT #3	0.9485	0.0000	0.9220	10	100%	0.1282			
EFF FAN MOTORS	0.3841	0.0000	2.5890	10	100%	0.0185	2.5890	0.3841	0.0000
					TOTAL	0.0077	16.8640	1.0433	0.0000
					% OF ENDUSE		31.8%		
					GRAND TOTAL	0.0108	20.236256825	1.79082	0.66236
							30.0%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	272,000	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		HOSPITAL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT	ALL FUELS (KWH/SF)	UIC EXIST. PROTOTYPE (KWH/SF)
HEATING	2.22	17.7%	12.54	43.55
COOLING	0.92	97.6%	0.94	3.20
VENTILATION	3.03	100.0%	3.03	7.02
WATER HEAT	2.19	31.0%	7.07	1.80
REFRIGERATION	0.00			
LIGHTING	7.88	100.0%	7.88	8.85
MISC.	0.64	85.2%	0.75	4.69
TOTAL	16.88	52.4%	32.21	69.11

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
ROOF INSUL. R7>R23	0.1204	0.0000	0.8910	30	5%	0.0080	0.0454	0.0061	0.0000
EFF. WINDOWS SG>DG	0.9038	0.0000	0.6779	20	5%	0.1000			
					TOTAL	0.0080	0.0454	0.0061	0.0000
					% OF ENDUSE		1.4%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	1.3338	1.5275	0.4964	30	100%	0.3423			
INCANDESCENT>PL	0.0158	-0.0552	0.3780	30	100%	-0.0062	0.3780	0.0158	-0.0552
OUTSIDE LIGHTS	0.0006	-0.0103	0.0173	30	100%	-0.0335	0.0173	0.0006	-0.0103
					TOTAL	-0.0074	0.3953	0.0163	-0.0655
					% OF ENDUSE		5.0%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
TEMP RESET	0.0465	0.0000	2.6287	10	18%	0.0022	0.4653	0.0082	0.0000
AAHX	0.4145	0.0000	3.8306	15	18%	0.0099	0.6780	0.0734	0.0000
FAN MOTORS	0.0985	0.0000	0.0797	15	100%	0.1129			
VAV	2.1601	0.0000	0.4859	15	18%	0.4060			
HEAT RECOVER DHW	0.0213	0.000	3.0000	15	23%	0.0006	0.6975	0.0049	0.0000
					TOTAL	0.0044	1.8408	0.0865	0.0000
					% OF ENDUSE		20.5%		
					GRAND TOTAL	0.0025	2.2815257691	0.109	-0.0655
							13.5%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	272,000	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		HOSPITAL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SA	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	4.64	17.7%	26.12	26.20
COOLING	1.66	97.6%	1.70	1.70
VENTILATION	6.10	100.0%	6.10	6.10
WATER HEAT	0.43	31.0%	1.40	1.40
REFRIGERATION	0.00			
LIGHTING	8.90	100.0%	7.68	8.90
MISC.	4.43	85.2%	5.20	5.20
TOTAL	26.16	54.3%	48.20	49.50

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0354	0.0000	0.0840	30	18%	0.0250	0.0149	0.0063	0.0000
INSULATE WALLS R5>R24	0.0886	0.0000	0.0526	30	13%	0.1001			
LOW E WINDOWS	0.2124	0.0000	0.1066	30	13%	0.1183			
					TOTAL	0.0250	0.0149	0.0063	0.0000
					% OF ENDUSE		0.2%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.1631	0.5106	1.2167	30	100%	0.0329	1.2167	0.1631	0.5106
FLUORESCENT>T8	0.1956	0.3609	0.4950	30	100%	0.0668			
INCANDESCENT>HALOGEN	0.0031	0.0021	0.1424	1	100%	0.0382	0.1424	0.0031	0.0021
EXIT SIGNS	0.0536	-0.0531	0.0848	30	100%	0.0003	0.0848	0.0536	-0.0531
DAYLIGHT DIM AFT #2	0.0767	0.0292	0.1644	15	75%	0.0588			
OCCUPANCY SENSOR AFT #2	0.1109	0.0238	0.1859	10	75%	0.0903			
AMBIENT/TASK AFT #2	0.0534	0.0358	0.1560	30	75%	0.0340	0.1170	0.0401	0.0269
					TOTAL	0.0310	1.5608	0.2599	0.4865
					% OF ENDUSE		17.5%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
AAHX	0.4384	0.0000	3.9065	15	13%	0.0102	0.5186	0.0582	0.0000
EFFICIENT CHILLER	0.0076	0	0.0119	15	97.60%	0.0587			
VAV	2.0507	0.0000	0.4945	15	13%	0.3787			
HEAT RECOVER DHW	0.5515	0.0000	0.7000	15	23%	0.0720			
EVAP COOLER	0.5616	0.0000	0.5040	15	73%	0.1018			
					TOTAL	0.0102	0.5186	0.0582	0.0000
					% OF ENDUSE		2.9%		
					GRAND TOTAL	0.0255	2.0942664638	0.32432	0.48652
							7.8%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	11,664	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		HOTEL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	ALL FUELS % S(KWH/SF)		EXISTING PROTOTYPE (KWH/SF)
HEATING	2.00	23.9%	8.37	11.72
COOLING	1.07	85.4%	1.25	0.64
VENTILATION	2.23	100.0%	2.23	0.04
WATER HEAT	0.56	20.0%	2.80	6.02
REFRIGERATION	0.00	100.0%		
LIGHTING	4.74	100.0%	4.74	3.72
MISC.	1.03	67.7%	1.52	1.94
TOTAL	11.63	55.6%	20.91	24.08

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
ROOF INSUL. R7>R27	0.2547	0.0000	0.9432	30	24%	0.0160	0.2254	0.0609	0.0000
WALL INSUL. R2>R11	0.2653	0.0000	4.4359	30	24%	0.0036	1.0602	0.0634	0.0000
WINDOW SG>DG	0.2102	0.0000	1.1317	20	24%	0.0139	0.2705	0.0502	0.0000
					TOTAL	0.0072	1.5561	0.1745	0.0000
					% OF ENDUSE		50.7%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INCANDESCENT>PL	1.7704	-1.0565	0.4185	15	100%	0.1558			
FLUORESCENT>T8	0.1204	0.0160	0.4616	15	100%	0.0270	0.4616	0.1204	0.0160
EXTERNAL>HPS	0.0793	0.0113	0.1740	15	100%	0.0476	0.1740	0.0793	0.0113
					TOTAL	0.0270	0.6356	0.1997	0.0273
					% OF ENDUSE		13.4%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
EFFICIENT THERMOSTAT	0.2915	0.0000	1.1130	15	25%	0.0239	0.2782	0.0729	0.0000
LOW FLOW SHOWER	0.0450	-0.2112	2.1652	10	60%	-0.0096	1.2991	0.0270	-0.1267
DHW & PIPE INSULATION	0.0257	0.0000	0.6331	10	40%	0.0051	0.2532	0.0103	0.0000
					TOTAL	-0.0025	1.8306	0.1102	-0.1267
					% OF ENDUSE		26.6%		
					GRAND TOTAL	0.0050	4.0222593754	0.48435	-0.0994
							34.6%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	11,664	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		HOTEL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	1.43	23.9%	4.23	6.00
COOLING	0.54	85.4%	0.49	0.63
VENTILATION	0.02	100.0%	0.02	0.02
WATER HEAT	1.21	20.0%	6.03	6.03
COOKING	0.00	100.0%		
LIGHTING	3.63	100.0%	3.40	3.63
MISC.	1.31	67.7%	1.94	1.94
TOTAL	8.14	55.6%	16.11	18.25

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT CODE>MCS	0.1948	0.0000	0.4311	30	23.9%	0.0268	0.1030	0.0466	0.0000
LOW E WINDOW U65>U39	0.2407	0.0000	0.7888	30	23.9%	0.0181	0.1885	0.0575	0.0000
INSULATE ROOF R19>R38	0.1767	0.0000	0.3522	30	23.9%	0.0298	0.0842	0.0422	0.0000
INSULATE WALL R19>R24	0.3543	0.0000	0.6908	20	23.9%	0.0385	0.1651	0.0847	0.0000
					TOTAL	0.0278	0.5408	0.2310	0.0000
					% OF ENDUSE		27.4%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT CODE>MCS	0.6541	-0.5180	0.2498	30	100.0%	0.0324	0.2498	0.6541	-0.5180
INCANDESCENT>PL	0.6541	-0.5180	0.2498	30	100.0%	0.0324	0.2498	0.6541	-0.5180
HPS EXTERIOR LIGHTS	0.1740	-0.0163	0.1740	30	100.0%	0.0538	0.1740	0.1740	-0.0163
					TOTAL	0.0324	0.6735	1.4823	-1.0524
					% OF ENDUSE		18.6%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
LOW FLOW SHOWER	0.0450	-0.2112	2.1652	10	16.0%	-0.0096	0.3464	0.0072	-0.0338
DHW & PIPE INSULATION	0.0257	0.0000	0.6331	10	16.0%	0.0051	0.1013	0.0041	0.0000
					TOTAL	-0.0063	0.4477	0.0113	-0.0338
					% OF ENDUSE		6.9%		
					GRAND TOTAL	0.0191	1.6620883181	1.72454	-1.0862
							16.4%		

INPUT ARRAY -- COMMERCIAL BUILDINGS		
EXISTING	408,000	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		LG OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% S(KWH/SF)	ALL FUELS	UIC EXIST. PROTOTYPE (KWH/SF)
HEATING	3.14	22.0%	14.25	12.46
COOLING	1.46	100.0%	1.46	2.57
VENTILATION	4.30	100.0%	4.30	5.55
WATER HEAT	0.41	38.0%	1.09	0.20
REFRIGERATION	0.00			
LIGHTING	6.56	100.0%	6.56	10.50
MISC.	0.35	85.5%	0.41	3.12
TOTAL	16.22	57.8%	28.07	34.40

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSUL. ROOF R6>R24	0.0263	0.0000	0.0919	30	17%	0.0170	0.0152	0.0043	0.0000
W1 WINDOW SG>DG	0.0173	0.0000	0.0168	30	17%	0.0612			
W2 LOW E. WINDOWS AFT W1	0.0040	0.0000	0.0049	30	17%	0.0484	0.0008	0.0007	0.0000
					TOTAL	0.0170	0.0160	0.0050	0.0000
					% OF ENDUSE		0.3%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
40W FLUORESCENT>T8	1.4529	0.1398	2.1112	15	100%	0.0689			
INCANDESCENT>PL	0.1650	-0.4153	0.4281	3	100%	-0.2116	0.4281	0.1650	-0.4153
EXIT SIGNS	0.1097	0.2608	0.1773	30	100%	0.1241			
AMBIENT/TASK AFT #1	0.4938	0.1358	1.1553	30	75%	0.0324	0.8665	0.3703	0.1019
DAYLIGHT DIM AFT #1	0.2822	0.0087	0.4250	15	75%	0.0625			
OCCUPANCY SENSOR AFT #1	0.2246	0.0186	1.2669	10	75%	0.0239	0.9502	0.1685	0.0140
					TOTAL	-0.0177	2.2448	0.7038	-0.2995
					% OF ENDUSE		34.2%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
TEMP RESET FOR MULTIZONE	0.0148	0.0000	0.0155	15	22%	0.0868			
EFF FANS	0.1115	0.0000	0.0089	15	100%	1.1435			
TUNE & ADJUST	0.0124	0.0000	0.0177	5	22%	0.1581			
TRAV RETROFIT	1.8382	-1.3595	3.5580	30	100%	0.0080	3.5580	1.8382	-1.3595
EFF CHILLER AT CHANGEOUT	0.1416	0.0000	0.0015	15	75%	8.4631			
					TOTAL	0.0080	3.5580	1.8382	-1.3595
					% OF ENDUSE		36.8%		
					GRAND TOTAL	-0.0019	5.8187689581	2.54705	-1.659
							35.9%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	408,000	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		LG OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELECT(kWh/SF)		MCS (KWH/SF)	PRACTICE (KWH/SF)
HEATING	1.10	22.0%	4.97	5.00
COOLING	0.70	100.0%	0.70	0.70
VENTILATION	2.10	100.0%	2.10	2.10
WATER HEAT	0.08	38.0%	0.20	0.20
REFRIGERATION	0.00			
LIGHTING	7.70	100.0%	6.14	7.70
MISC.	3.08	85.5%	3.60	3.60
TOTAL	14.75	83.3%	17.71	19.30

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	EFFECTIVE SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0303	0	0.0320	25	22.0%	0.0620			
LOW E. WINDOWS	0.7124	0	0.2785	20	22.0%	0.1919			
						TOTAL	0.0000	0.0000	0.0000
						% OF ENDUSE	0.0%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	EFFECTIVE SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.2620	-0.0976	1.5556	30	100.00%	0.0063	1.5556	0.2620	-0.0976
REDUCE LIGHT LEVEL	0.0829	0.0913	0.8522	30	100.00%	0.0121	0.8522	0.0829	0.0913
EXIT SIGNS	0.0537	-0.0745	0.1792	30	100.00%	-0.0069	0.1792	0.0537	-0.0745
OCCUPANCY SENSOR AFTER #2	0.2246	0.0119	1.7542	10	100.00%	0.0168	1.7542	0.2246	0.0119
AMBIENT/TASK AFTER #4	0.4938	0.1237	1.6964	30	100.00%	0.0216	1.6964	0.4938	0.1237
					TOTAL	0.0141	6.0377	1.1170	0.0548
					% OF ENDUSE		78.4%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	EFFECTIVE SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0010	0	0.0011	15	100.00%	0.0875			
VSD MOTORS	0.0459	0	0.1894	15	100%	0.0221	0.1894	0.0459	0.0000
TRAV CONTROLS	1.8382	-0.4740	1.5572	30	100%	0.0520			
EVAP COOLING	0.5616	0	0.1882	15	75%	0.2725			
					TOTAL	0.0221	0.1894	0.0459	0.0000
					% OF ENDUSE		2.3%		
					GRAND TOTAL	0.0143	6.2270624454	1.16292	0.0548
							38.7%		

INPUT ARRAY -- COMMERCIAL BUILDINGS		
EXISTING	4,880	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELECT(kWh/SF)	% SAT.	MCS (KWH/SF)	PRACTICE (KWH/SF)
HEATING	1.48	16.0%	9.22	9.41
COOLING	2.69	67.5%	3.99	4.08
VENTILATION	1.77	100.0%	1.77	1.77
WATER HEAT	0.21	38.0%	0.54	0.54
REFRIGERATION	0.00			
LIGHTING	7.11	100.0%	7.11	7.00
MISC.	0.43	85.5%	0.50	0.50
TOTAL	13.69	59.2%	23.13	23.29

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R4>R24	0.3312	0	1.6399	25	16.0%	0.0132	0.2624	0.0530	0.0000
INSUL. WALL R5>R24	6.4168	0	2.8356	25	16.0%	0.1482			
WINDOWS SG>DG	1.4499	0	2.0947	25	16.0%	0.0453	0.3351	0.2320	0.0000
LOW E. WINDOWS	1.0529	0	0.6142	20	16.0%	0.1286			
SOLAR FILM	0.5895	0	1.1035	15	67.5%	0.0488	0.7448	0.3979	0.0000
					TOTAL	0.0132	1.3424	0.6829	0.0000
					% OF ENDUSE		32.2%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	1.0209	0.1749	1.7786	30	100.00%	0.0399	1.7786	1.0209	0.1749
EXIT SIGNS	0.0496	-0.0622	0.1564	30	100.00%	-0.0048	0.1564	0.0496	-0.0622
INCAND. FLOOD > HALOGEN	0.0038	0.0014	0.0937	1	100.00%	0.0585			
DAYLIGHT DIM AFT #1	0.5570	0.0612	1.2901	30	100.00%	0.0285	1.2901	0.5570	0.0612
OCCUPANCY SENSOR AFT #1	0.2809	0.0074	0.1553	30	100.00%	0.1102			
AMBIENT/TASK AFT #1	0.9910	0.1318	1.1703	30	100.00%	0.0570			
					TOTAL	0.0332	3.2250	1.6275	0.1739
					% OF ENDUSE		45.4%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
ECONOMIZER	0.4262	0	1.3656	15	67.50%	0.0285	0.9218	0.2877	0.0000
OPTIMUM START TIMER	0.3084	0	0.9004	15	12.00%	0.0313	0.1080	0.0370	0.0000
AAHX	1.0362	0	1.3991	15	12.00%	0.0676			
REDUCE OUTSIDE AIR	0.0130	0	1.3556	15	12.00%	0.0009	0.1627	0.0016	0.0000
RESISTANCE>HEAT PUMP	3.0502	0	4.8840	15	49.00%	0.0570			
EFF HEAT PUMP	1.0362	0	0.5154	15	20.00%	0.1836			
					TOTAL	0.0250	1.1925	0.3263	0.0000
					% OF ENDUSE		18.1%		
					GRAND TOTAL	0.0300	5.7599035064	2.63665	0.17393
							42.1%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	4,880	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELECT(kWh/SF)	% SAT.	MCS (KWH/SF)	PRACTICE (KWH/SF)
HEATING	0.74	16.0%	4.53	4.60
COOLING	1.49	67.5%	2.06	2.20
VENTILATION	2.20	100.0%	1.10	2.20
WATER HEAT	0.21	38.0%	0.50	0.54
REFRIGERATION	0.00			
LIGHTING	6.00	100.0%	6.17	6.00
MISC.	2.91	85.5%	0.50	3.40
TOTAL	13.53	91.1%	14.85	18.94

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0322	0	0.0900	25	16.0%	0.0234	0.0144	0.0051	0.0000
INSUL. WALL R11>R16	0.3459	0	0.1143	25	16.0%	0.1983			
INSULATE ROOF R13>R30	0.0957	0	0.1248	25	16.0%	0.0502	0.0200	0.0153	0.0000
INSULATE ROOF R30>R38	0.0697	0	0.0315	25	16.0%	0.1449			
LOW E. WINDOWS	1.0529	0	0.5292	20	100.0%	0.1493			
					TOTAL	0.0234	0.0344	0.0205	0.0000
					% OF ENDUSE		1.5%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.3959	0.0602	1.3646	30	100.00%	0.0198	1.3646	0.3959	0.0602
REDUCE LIGHT LEVEL	0.1693	0.1308	0.4861	30	100.00%	0.0367	0.4861	0.1693	0.1308
EXIT SIGNS	0.0496	-0.0527	0.1575	30	100.00%	-0.0012	0.1575	0.0496	-0.0527
DAYLIGHT DIM AFT #1	0.5570	0.1394	1.1807	30	100.00%	0.0350	1.1807	0.5570	0.1394
OCCUPANCY SENSOR AFT #1	0.2809	0.0168	0.1565	30	100.00%	0.1130			
AMBIENT/TASK AFT #1	0.9910	0.2027	1.1807	30	100.00%	0.0600			
					TOTAL	0.0270	3.1889	1.1717	0.2778
					% OF ENDUSE		53.1%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0852	0	0.1410	15	100.00%	0.0552			
ECONOMIZER	0.4262	0	0.7160	15	67.50%	0.0544	0.4833	0.2877	0.0000
OPTIMUM START TIMER	0.3084	0	0.3557	15	12.00%	0.0792			
AAHX	1.0362	0	0.5527	15	12.00%	0.1712			
REDUCE OUTSIDE AIR	0.0130	0	0.5355	15	12.00%	0.0022	0.0643	0.0016	0.0000
HEAT PUMP UPGRADE	1.0362	0	0.7731	15	20.00%	0.1224			
					TOTAL	0.0022	0.5476	0.2893	0.0000
					% OF ENDUSE		4.9%		
					GRAND TOTAL	0.0265	3.7708406857	1.48145	0.27775
							21.9%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	13,125	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		RETAIL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	EUI(kWh/SF)	% SAT.	ALL FUELS (KWH/SF)	UIC PROTOTYPE (KWH/SF)
HEATING	2.01	13.90%	14.45	5.70
COOLING	1.67	73.50%	2.27	2.48
VENTILATION	5.88	100.00%	5.88	1.15
WATER HEAT	0.04	31.60%	0.12	0.42
REFRIGERATION	0.00			
LIGHTING	6.71	100.00%	6.71	8.62
MISC.	0.61	95.20%	0.64	1.14
TOTAL	16.92	56.27%	30.07	19.51

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R7>R20	0.6621	0.0000	3.1217	30	10%	0.0126	0.3254	0.0690	0.0000
INSULATE WALL R3>R22	2.6309	0.0000	1.4497	30	10%	0.1078			
LOW E. WINDOWS	0.5731	0.0000	0.6641	30	10%	0.0512	0.0692	0.0597	0.0000
WEATHERSTRIP ACH	0.0123	0.0000	0.0048	10	10%	0.3203			
					TOTAL	0.0126	0.3947	0.1288	0.0000
					% OF ENDUSE		10.7%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	0.8347	0.5550	2.4110	30	100%	0.0342	2.4110	0.8347	0.5550
INCANDESCENT>HALOGEN	0.0040	0.0685	0.9359	1	100%	0.0807			
DAYLIGHT DIM AFT #1	0.0678	0.0824	0.8727	30	100%	0.0102	0.8727	0.0678	0.0824
EXIT SIGNS	0.0352	0.0156	0.0356	30	100%	0.0846			
					TOTAL	0.0278	3.2838	0.9026	0.6374
					% OF ENDUSE		48.9%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
AAHX	0.6604	0.0000	0.6830	14.0	10%	0.0929			
RESISTANCE > HEAT PUMP	3.5315	0.0000	2.8524	15.0	8%	0.1131			
DHW BLANKET	0.0046	0.0000	0.0315	10.0	24%	0.0181	0.0075	0.0011	0.0000
					TOTAL	0.0181	0.0075	0.0011	0.0000
					% OF ENDUSE		0.1%		
					GRAND TOTAL	0.0265	3.6858982306	1.03241	0.63744
							21.8%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	13,124	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		RETAIL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	MCS(kWh/SF)	MCS PROTOTYPE % SAT.	MCS PROTOTYPE (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	0.14	13.90%	0.98	1.00
COOLING	1.03	73.50%	1.29	1.40
VENTILATION	1.70	100.00%	1.70	1.70
WATER HEAT	0.01	31.60%	0.04	0.04
REFRIGERATION				
LIGHTING	9.20	100.00%	8.96	9.20
MISC.	0.94	85.20%	1.10	1.10
TOTAL	13.02	92.54%	14.07	14.44

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT CODE>MCS	0.0062	0	0.0230	30	14%	0.0159	0.0032	0.0009	0.0000
DG > LOW E WINDOWS	0.0787	0.0000	0.1503	20	14%	0.0393	0.0209	0.0109	0.0000
					TOTAL	0.0362	0.0241	0.0118	0.0000
					% OF ENDUSE		2.1%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT CODE>MCS	0.0575	-1.7658	0.3441	30	100%	-0.2948	0.3441	0.0575	-1.7658
FLUORESCENT>T8	0.4300	0.5394	2.0597	30	100%	0.0279	2.0597	0.4300	0.5394
INCANDESCENT>HALOGEN	0.0094	-0.0178	1.0445	1	100%	-0.0084	1.0445	0.0094	-0.0178
DAYLIGHT DIM AFT #1	0.0678	0.0358	0.7317	15	100%	0.0129	0.7317	0.0678	0.0358
EXIT SIGNS	0.0245	0.0068	0.0856	30	100%	0.0218	0.0856	0.0245	0.0068
					TOTAL	-0.0097	4.2656	0.5892	-1.2016
					% OF ENDUSE		46.4%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0254	0.0000	0.0140	15	14%	0.1653			
AAHX	0.6605	0.0000	0.6607	15	10%	0.0913			
EFF HEAT PUMP UPGRADE	0.7568	0.0000	0.1978	15	20%	0.3494			
RADIANT HEATERS (STORAGE)	0.0358	0.0000	0.0966	15	10%	0.0339	0.0101	0.0037	0.0000
					TOTAL	0.0339	0.0101	0.0037	0.0000
					% OF ENDUSE		0.2%		
					GRAND TOTAL	-0.0093	4.29977	0.604753708	-1.2016
							32.2%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	67,784	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		SCHOOL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% SAT.	ALL FUELS (KWH/SF)	UIC PROTOTYPE (KWH/SF)
HEATING	1.79	9.8%	18.24	16.07
COOLING	0.03	42.9%	0.07	0.00
VENTILATION	1.46	100.0%	1.46	1.18
WATER HEAT	0.10	38.3%	0.25	0.55
REFRIGERATION	0.00			
LIGHTING	4.72	100.0%	4.72	3.92
MISC.	0.50	88.5%	0.56	0.92
TOTAL	8.60	34.0%	25.30	22.64

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATE ROOF R7> R27	0.602	0.000	2.3756	30	10%	0.0150	0.2328	0.0590	0.0000
LOW E WINDOWS	1.875	0.000	2.1147	20	10%	0.0665			
INSULATE WALLS R4>R23	3.276	0.000	2.0335	30	10%	0.0957			
WEATHERSTRIP ACH	0.267	0.000	2.4487	10	10%	0.0136	0.2400	0.0261	0.0000
					TOTAL	0.0143	0.4728	0.0851	0.0000
					% OF ENDUSE		26.0%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
FLUORESCENT>T8	0.7753	0.2020	1.3780	30	100%	0.0421	1.3780	0.7753	0.2020
INCANDESCENT>PL	0.2128	-0.1524	0.3548	15	100%	0.0156	0.3548	0.2128	-0.1524
EXIT SIGNS	0.1072	-0.0811	0.1190	30	100%	0.0130	0.1190	0.1072	-0.0811
DAYLIGHT DIM AFT #1	0.0987	0.0063	0.0932	15	75%	0.1030			
OCCUPANCY SENSOR AFT #1	0.2438	0.0318	0.4677	15	75%	0.0538	0.3508	0.1829	0.0239
					TOTAL	0.0352	2.2026	1.2783	-0.0077
					% OF ENDUSE		46.7%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
ADJUST OUTSIDE AIR	0.033	0.000	2.0006	5.0	10%	0.0037	0.1961	0.0032	0.0000
DHW BLANKET	0.005	0.000	0.0680	10.0	29%	0.0100	0.0195	0.0016	0.0000
					TOTAL	0.0043	0.2156	0.0048	0.0000
					% OF ENDUSE		5.6%		
					GRAND TOTAL	0.0287	2.8909621592	1.36817	-0.0077
							33.6%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	277,200	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		SCHOOL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:

	ELEC(kWh/SF)	% SAT.	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	1.14	9.90%	11.40	11.50
COOLING	0.13	42.90%	0.30	0.30
VENTILATION	2.20	100.00%	2.22	2.20
WATER HEAT	0.57	38.30%	1.50	1.50
REFRIGERATION				
LIGHTING	5.20	100.00%	4.41	5.20
MISC.	1.15	88.50%	1.30	1.30
TOTAL	10.39	49.18%	21.13	22.00

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0023	0.0000	0.0237	30	10%	0.0058	0.0023	0.0002	0.0000
INSULATE ROOF R19> R38	0.0728	0.0000	0.1579	30	10%	0.0274	0.0156	0.0072	0.0000
INSULATE WALLS R6>R19	0.0587	0.0000	0.1334	30	10%	0.0261	0.0132	0.0058	0.0000
INSULATE WALLS>R24 AFT #3	0.0503	0.0000	0.0907	30	10%	0.0329	0.0090	0.0050	0.0000
LOW E WINDOWS	0.0728	0.0000	0.0750	30	10%	0.0576			
					TOTAL	0.0270	0.0402	0.0182	0.0000
					% OF ENDUSE		3.2%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0341	-0.0166	0.0564	30	100%	0.0185	0.0564	0.0341	-0.0166
FLUORESCENT>T8	0.1438	0.1188	0.2300	30	100%	0.0678			
EXIT SIGNS	0.0131	-0.0188	0.0341	30	100%	-0.0099	0.0341	0.0131	-0.0188
DAYLIGHT DIM AFT #1	0.0241	0.0000	0.0283	15	100%	0.0779			
OCCUPANCY SENSOR AFT #1	0.0596	0.0000	0.1105	10	100%	0.0672			
					TOTAL	0.0078	0.0905	0.0472	-0.0353
					% OF ENDUSE		1.7%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0006	0.0000	0.0000	15	10%	1.2294			
VSD MOTORS	0.0450	0.0000	0.0595	15	75%	0.0691			
EMCS CONTROLS	0.2755	0.0321	0.2444	15	10%	0.1150			
					TOTAL		0.0000	0.0000	0.0000
					% OF ENDUSE		0.0%		
					GRAND TOTAL	0.0137	0.1306650778	0.06539	-0.0353
							1.2%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

EXISTING	18,025	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		WAREHOUSE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% S(KWH/SF)	ALL FUELS	UIC EXIST. PROTOTYPE (KWH/SF)
HEATING	0.48	6.7%	7.16	8.30
COOLING	0.05	73.8%	0.07	0.38
VENTILATION	0.03	100.0%	0.03	0.23
WATER HEAT	0.01	52.2%	0.02	0.15
REFRIGERATION	5.00	100.0%	5.00	
LIGHTING	3.29	100.0%	3.29	3.50
MISC.	3.02	97.6%	3.09	1.72
TOTAL	11.88	63.7%	18.66	14.28

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
INSULATED ROOF R2>R20	0.6015	0.000	3.4043	30	7%	0.0105	0.2281	0.0403	0.0000
INSULATED WALL R2>R20	2.0340	0.000	2.4693	30	7%	0.0489	0.1654	0.1363	0.0000
LOW E WINDOWS SG>DG	0.4889	0.000	0.3799	20	7%	0.0965			
WEATHERSTRIP ACH	0.0433	0.000	0.1912	10	7%	0.0282	0.0128	0.0029	0.0000
					TOTAL	0.0114	0.4063	0.1795	0.0000
					% OF ENDUSE		76.7%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
OFFICE FLUORESCENT>T8	0.1369	0.044	0.1663	25	100%	0.0715			
STORAGE DELAMP	0.1363	0.000	0.2342	25	100%	0.0380	0.2342	0.1363	-0.0004
INCANDESCENT>HALOGEN, HID	0.0054	0.000	0.2879	1	100%	0.0193	0.2879	0.0054	-0.0001
					TOTAL	0.0380	0.5220	0.1417	-0.0005
					% OF ENDUSE		15.9%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
REDUCE OUTSIDE AIR	0.0051	0.000	0.1680	5	7%	0.0069	0.0113	0.0003	0.0000
TEMP SETBACK	0.0902	0.000	1.8826	10	7%	0.0060	0.1261	0.0060	0.0000
RADIANT HEATERS	1.0787	0.000	3.2221	15	7%	0.0306	0.2159	0.0723	0.0000
AAHX	0.2405	0.000	0.1595	15	7%	0.1377			
RESIST> HP (OFFICE)	0.4675	0.000	0.6382	15	1%	0.0669			
EFFICIENT REFER.	0.7772	0.000	3.5000	15	7%	0.0203	0.2345	0.0521	0.0000
DESTRATIFIERS	0.1703	0.000	2.0310	15	7%	0.0077	0.1361	0.0114	0.0000
DHW BLANKET	0.0035	0.000	0.0229	10	39%	0.0192	0.0090	0.0014	0.0000
ECONOMIZER (OFFICE)	0.0835	0.000	0.1381	15	55%	0.0552			
					TOTAL	0.0183	0.7328	0.1435	0.0000
					% OF ENDUSE		8.5%		
					GRAND TOTAL	0.0207	1.6612115035	0.46467	-0.0005
							14.0%		

INPUT ARRAY -- COMMERCIAL BUILDINGS

NEW	18,025	SQFT
STATE:		UTAH
ZONE:		0
BUILDING TYPE:		WAREHOUSE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1989

ABSOLUTE ENERGY USE BY ENDUSE:	ELEC(kWh/SF)	% SAT.	MCS (KWH/SF)	CURRENT PRACTICE (KWH/SF)
HEATING	0.18	6.7%	2.68	2.70
COOLING	0.15	73.8%	0.19	0.20
VENTILATION	0.40	100.0%	0.40	0.40
WATER HEAT	0.10	52.2%	0.20	0.20
REFRIGERATION	0.50	100.0%	4.00	0.50
LIGHTING	3.30	100.0%	2.41	3.30
MISC.	1.17	97.6%	1.20	1.20
TOTAL	5.80	52.4%	11.08	8.50

BUILDING ENVELOPE MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0079	0	0.0190	30	7%	0.0247	0.0013	0.0005	0.0000
INSULATED WALL R11>R16	0.1040	0	0.3130	25	6.7%	0.0218	0.0210	0.0070	0.0000
INSULATED WALL R11>R24	0.3865	0.000	0.0429	30	7%	0.5352			
LOW E WINDOWS	0.1351	0.000	0.0139	30	7%	0.5783			
INSULATE ROOF>R30	0.1772	0.000	0.0290	30	7%	0.3624			
					TOTAL	0.0219	0.0222	0.0075	0.0000
					% OF ENDUSE		6.8%		

BUILDING LIGHTING MEASURES:

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	-0.0156	-0.0931	0.8911	30	100%	-0.0072	0.8911	-0.0156	-0.0931
EXIT SIGNS	0.0268	0.0159	0.0589	30	100%	0.0430	0.0589	0.0268	0.0159
AMBIENT/TASK LIGHT AFT #1	0.0683	0.0299	0.1764	30	100%	0.0330	0.1764	0.0683	0.0299
DAYLIGHT DIM AFT #1	0.0692	0.0120	0.1065	15	100%	0.0697			
OCCUPANCY SENSOR AFT #1	0.0421	0.0346	0.4228	10	100%	0.0226	0.4228	0.0421	0.0346
					TOTAL	0.0074	1.5492	0.1215	-0.0127
					% OF ENDUSE		46.9%		

BUILDING EQUIPMENT MEASURES

MEASURES	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (KWH/SF)	LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/KWH)	SOCIETAL TEST SAVINGS KWH/SQFT	COST $/SQFT	O&M $/SQFT
CURRENT PRACTICE>MCS	0.0185	0	0.0140	15	7%	0.1207			
EFFICIENT REFER.	0.6670	0.000	3.5000	15	75%	0.0174	2.6250	0.5003	0.0000
ECONOMIZER	0.0577	0.000	0.1435	15	55%	0.0367	0.0794	0.0319	0.0000
					TOTAL	0.0180	2.7044	0.5322	0.0000
					% OF ENDUSE		79.7%		
					GRAND TOTAL	0.0142	4.2758793076	0.66119	-0.0127
							73.7%		

4.3. Commercial Sector Capacity Savings

The appropriate conservation load factor for commercial buildings was computed by independent computer modeling. Copies of the DOE-2 models were obtained from BPA and their consultant. Since the BPA analysis lists only energy savings, these models were run again to estimate demand savings. The process is complicated because there are a variety of fuel choices, building types and measures. To simplify the analysis, runs were completed for the current practice and fully cost-effective cases only. Fuel choices included electric, gas and heat pump as appropriate for the building type.

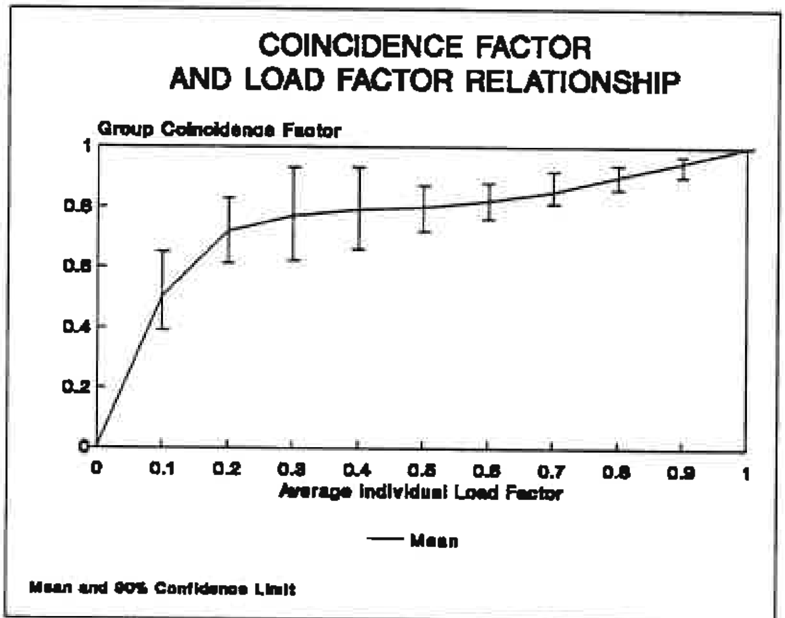


Figure 11 Aggregate Coincidence Factor

The computer modeling provides some idea of demand impact but will be based on average within the hour rather than 15 minute demand. This may not be a problem since the result sought is actually the interactive impact of a group of similar buildings. A key assumption is an estimate of the likelihood that such buildings will be impacting system peak at the same time. One would expect that a likelihood factor will be some function of the duty cycle or load factor of the modeled building. A reference was located which described a function for this likelihood factor (Association of Edison Illuminating Companies, "Report of Special Committee on Load Studies", 1939, p. 82). Obviously this is a dated reference, however, there is no reason that the likelihood factor would be different today. We would be interested in locating other references. The likelihood function used in shown in Figure 11. The aggregate conservation load factor that results is in the range 0.6 to 0.8 or fairly close to the 0.6 assumed previously in RAMPP-1. There is some variation by season and space heat fuel saturation. Results by state and market segment are shown below for major building types. For purposes of estimating program impact, a weighted average of the major segments listed in Table 10 through Table 14 was applied as representative to the entire commercial sector.

Table 10 Grocery Demand Factor

Grocery, Existing baseline

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
29.0%	55.0%	15.2%	31.0%

WEIGHTED AVERAGE SEASONALITY FACTOR

CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.0929	0.0959	0.0867	0.0928
Feb	0.0803	0.0824	0.0757	0.0787
Mar	0.0866	0.0874	0.0818	0.0847
Apr	0.0798	0.0798	0.0774	0.0776
May	0.0783	0.0802	0.0819	0.0806
Jun	0.0779	0.0765	0.0842	0.0796
Jul	0.0843	0.0811	0.0944	0.0868
Aug	0.0831	0.0795	0.0900	0.0853
Sep	0.0773	0.0756	0.0814	0.0788
Oct	0.0829	0.0813	0.0804	0.0810
Nov	0.0848	0.0855	0.0801	0.0829
Dec	0.0918	0.0948	0.0859	0.0912
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR

ENERGY SAVINGS/730/PEAK SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	1.2324	1.3213	1.1294	1.1741
Feb	1.0516	1.0205	1.1036	1.0840
Mar	1.0371	0.9780	1.1359	1.1242
Apr	0.9981	0.9636	1.0926	1.0448
May	1.1054	1.2312	1.1598	1.1286
Jun	1.1030	0.9547	0.9207	1.0312
Jul	0.9901	0.9786	1.0683	1.0570
Aug	0.9448	1.1974	1.1604	0.9844
Sep	1.0585	1.1135	1.1877	1.0792
Oct	1.0085	0.9711	1.1232	1.0875
Nov	1.0282	1.0259	1.1167	1.0919
Dec	1.1036	1.0428	1.1318	1.0513
Annual	1.0518	1.0561	1.1060	1.0767

Grocery, new baseline

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
0.409	0.402	0.147	0.485

WEIGHTED AVERAGE SEASONALITY FACTOR

CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.0772	0.0754	0.0806	0.0797
Feb	0.0708	0.0713	0.0703	0.0698
Mar	0.0775	0.0803	0.0798	0.0789
Apr	0.0806	0.0790	0.0821	0.0797
May	0.0887	0.0861	0.0869	0.0867
Jun	0.0903	0.0866	0.0896	0.0866
Jul	0.0954	0.0933	0.0906	0.0946
Aug	0.0922	0.0948	0.0869	0.0946
Sep	0.0891	0.0875	0.0869	0.0868
Oct	0.0841	0.0882	0.0858	0.0871
Nov	0.0745	0.0801	0.0796	0.0799
Dec	0.0797	0.0773	0.0791	0.0757
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR

ENERGY SAVINGS/730/PEAK SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	1.1288	1.1490	1.6783	1.1617
Feb	1.2506	1.5096	1.5334	1.3878
Mar	1.1910	1.4866	1.3557	1.4822
Apr	1.6403	1.3330	1.5041	1.2629
May	1.3212	1.2773	1.0407	1.3280
Jun	1.1993	1.2185	0.9236	1.2382
Jul	1.1291	1.0149	1.2641	0.9592
Aug	1.1900	1.2990	1.0358	1.0567
Sep	1.2272	1.0971	1.1147	1.3290
Oct	1.3061	1.3126	1.4007	1.4800
Nov	1.0518	1.2946	1.6813	1.1806
Dec	1.1325	1.1606	1.0178	1.0971
Annual	1.2180	1.2442	1.2375	1.2226

Table 11 Large Office Demand Factors

Large Office, Existing baseline

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
29.4%	29.4%	29.4%	22.0%

HEAT PUMP SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima

WEIGHTED AVERAGE SEASONALITY FACTOR

CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.1005	0.1031	0.1136	0.1046
Feb	0.0891	0.0889	0.0941	0.0893
Mar	0.0973	0.0935	0.1006	0.0932
Apr	0.0813	0.0794	0.0804	0.0813
May	0.0810	0.0802	0.0813	0.0816
Jun	0.0737	0.0746	0.0663	0.0732
Jul	0.0574	0.0594	0.0464	0.0584
Aug	0.0699	0.0744	0.0581	0.0676
Sep	0.0694	0.0698	0.0622	0.0716
Oct	0.0894	0.0898	0.0876	0.0878
Nov	0.0931	0.0890	0.0984	0.0925
Dec	0.0981	0.0980	0.1110	0.0989
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR

ENERGY SAVINGS/730/PEAK SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.9311	0.6201	0.4469	1.1120
Feb	0.6807	0.5470	0.3985	0.5973
Mar	0.7037	0.5275	0.4101	0.5222
Apr	0.5947	0.4690	0.4254	0.4667
May	0.6074	0.5121	0.4941	0.5563
Jun	0.7489	0.8799	0.5864	1.3091
Jul	0.9480	1.8537	0.4959	1.2283
Aug	1.8418	3.4829	2.1468	3.9082
Sep	0.5477	0.5218	0.6641	0.5156
Oct	0.5755	0.4922	0.4861	0.6083
Nov	0.6024	0.5145	0.4903	0.5224
Dec	0.6753	0.5578	0.4957	0.6299
Annual	0.6995	0.6100	0.4932	0.6727

Large Office, new baseline

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
33.6%	35.1%	25.2%	42.5%

HEAT PUMP SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
23.2%	24.2%	22.9%	38.6%

WEIGHTED AVERAGE SEASONALITY FACTOR

CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.0730	0.0783	0.0729	0.0681
Feb	0.0673	0.0725	0.0671	0.0647
Mar	0.0783	0.0818	0.0807	0.0784
Apr	0.0812	0.0813	0.0797	0.0846
May	0.0911	0.0872	0.0894	0.0940
Jun	0.0918	0.0872	0.0913	0.0939
Jul	0.1004	0.0932	0.0996	0.0999
Aug	0.1001	0.0924	0.0991	0.1008
Sep	0.0869	0.0851	0.0882	0.0893
Oct	0.0847	0.0858	0.0864	0.0879
Nov	0.0733	0.0778	0.0743	0.0726
Dec	0.0719	0.0775	0.0714	0.0658
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR

ENERGY SAVINGS/730/PEAK SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.7399	0.9239	0.8986	0.8667
Feb	0.7374	0.9903	0.9964	1.4960
Mar	0.7734	1.1233	1.0725	1.5065
Apr	0.7857	0.9728	1.2144	1.0471
May	0.9058	1.6604	0.5737	0.7770
Jun	0.8616	2.8266	0.6420	0.6376
Jul	0.8119	2.6013	0.6391	0.6184
Aug	0.7793	4.7637	0.7479	0.6476
Sep	0.8610	1.9979	0.5980	0.7559
Oct	0.8780	1.7795	0.7556	0.6236
Nov	0.7814	1.1199	0.9950	0.8647
Dec	0.6738	0.8444	0.8028	1.0214
Annual	0.7994	1.4150	0.7706	0.8047

Table 12 Small Office Demand Factors

Small Office, existing baseline

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
26.0%	42.0%	16.0%	36.0%

HEAT PUMP SATURATION BY CITY

WEIGHTED AVERAGE SEASONALITY FACTOR
CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.1150	0.1489	0.1047	0.1263
Feb	0.0911	0.1158	0.0815	0.0913
Mar	0.0938	0.1263	0.0810	0.0902
Apr	0.0780	0.0870	0.0753	0.0728
May	0.0702	0.0629	0.0616	0.0688
Jun	0.0678	0.0449	0.0806	0.0676
Jul	0.0703	0.0262	0.0779	0.0646
Aug	0.0734	0.0453	0.0854	0.0716
Sep	0.0638	0.0371	0.0745	0.0646
Oct	0.0765	0.0817	0.0804	0.0745
Nov	0.0910	0.0920	0.0790	0.0865
Dec	0.1090	0.1317	0.0962	0.1212
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR
ENERGY SAVINGS/730/PEAK SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	1.0116	0.9639	0.7479	0.8223
Feb	0.6931	0.9405	0.5713	0.6248
Mar	0.6618	0.5164	0.5696	0.6101
Apr	0.6256	0.4705	0.5545	0.5502
May	0.4021	0.2049	0.3362	0.5078
Jun	0.4328	0.4984	0.4646	0.4792
Jul	0.4718	0.3087	0.4094	0.4140
Aug	0.5806	0.5746	0.5606	0.5350
Sep	0.3520	1.3620	0.3459	0.4026
Oct	0.5624	0.5100	0.4372	0.3507
Nov	0.6811	1.5606	0.5041	0.4953
Dec	0.9046	0.8104	0.6679	0.8483
Annual	0.5913	0.5987	0.4947	0.5442

Small Office, new baseline

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
33.6%	35.1%	25.2%	42.5%

HEAT PUMP SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
6.5%	14.2%	15.8%	11.8%

WEIGHTED AVERAGE SEASONALITY FACTOR
CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.0784	0.0907	0.0906	0.0999
Feb	0.0716	0.0744	0.0708	0.0734
Mar	0.0816	0.0809	0.0774	0.0772
Apr	0.0807	0.0776	0.0755	0.0780
May	0.0981	0.0830	0.0886	0.0868
Jun	0.0938	0.0891	0.0888	0.0892
Jul	0.0936	0.0926	0.0906	0.0866
Aug	0.0995	0.0942	0.0954	0.0902
Sep	0.0818	0.0797	0.0831	0.0780
Oct	0.0783	0.0780	0.0838	0.0790
Nov	0.0699	0.0727	0.0704	0.0714
Dec	0.0729	0.0870	0.0850	0.0904
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR
ENERGY SAVINGS/730/PEAK SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.6224	1.1367	1.4451	1.4550
Feb	0.4745	0.9054	1.0137	1.0573
Mar	0.5710	0.8540	0.7860	0.7291
Apr	0.5588	0.8096	1.2204	0.6509
May	0.4064	0.5540	0.5518	0.6278
Jun	0.5709	0.7280	0.2826	0.7802
Jul	0.5589	0.7301	1.2117	0.6974
Aug	0.4710	0.7386	1.0205	0.7064
Sep	0.5264	0.7902	0.5494	0.6009
Oct	0.5688	0.7451	0.5891	0.6696
Nov	0.5517	0.8610	0.9269	0.8071
Dec	0.6697	0.9068	1.2167	1.0595
Annual	0.5328	0.7916	0.7266	0.7767

Table 13 Restaurant Demand Factors

Fast Food - Existing Buildings

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
30.0%	37.0%	26.2%	29.0%

HEAT PUMP SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima

WEIGHTED AVERAGE SEASONALITY FACTOR

CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.1396	0.1307	0.1393	0.1428
Feb	0.1034	0.1048	0.1003	0.1012
Mar	0.1037	0.1020	0.0921	0.1005
Apr	0.0791	0.0825	0.0762	0.0731
May	0.0582	0.0629	0.0602	0.0573
Jun	0.0483	0.0524	0.0570	0.0536
Jul	0.0501	0.0564	0.0638	0.0596
Aug	0.0494	0.0540	0.0598	0.0582
Sep	0.0536	0.0535	0.0556	0.0534
Oct	0.0831	0.0729	0.0670	0.0705
Nov	0.1039	0.1013	0.0982	0.1007
Dec	0.1278	0.1268	0.1306	0.1293
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR

ENERGY SAVINGS/730/PEAK SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.8664	0.7391	1.0224	0.8972
Feb	0.7737	0.7916	0.7836	0.8335
Mar	0.6978	0.7527	0.8022	1.0322
Apr	0.6894	0.8030	0.7367	0.6957
May	0.6248	1.4056	0.6335	0.8367
Jun	0.7595	1.4280	1.1292	1.3917
Jul	1.2027	1.2098	1.3394	1.4727
Aug	1.2363	1.1348	1.4456	1.5940
Sep	0.6120	1.4958	1.5996	0.8963
Oct	0.6751	0.5949	0.8447	0.9246
Nov	0.7497	0.6925	0.7568	0.9241
Dec	0.8669	0.6761	1.0792	0.7789
Annual	0.7717	0.8219	0.9215	0.9257

Fast Food - New, Baseline

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
37.1%	41.2%	40.0%	33.0%

HEAT PUMP SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
4.6%	10.0%	7.7%	11.4%

WEIGHTED AVERAGE SEASONALITY FACTOR

CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.1722	0.1566	0.1831	0.1882
Feb	0.1220	0.1167	0.1237	0.1131
Mar	0.1155	0.1055	0.0966	0.1070
Apr	0.0745	0.0765	0.0716	0.0636
May	0.0386	0.0521	0.0394	0.0361
Jun	0.0274	0.0411	0.0340	0.0360
Jul	0.0299	0.0481	0.0401	0.0470
Aug	0.0293	0.0446	0.0374	0.0447
Sep	0.0358	0.0397	0.0334	0.0357
Oct	0.0780	0.0653	0.0529	0.0562
Nov	0.1159	0.1049	0.1126	0.1088
Dec	0.1609	0.1488	0.1752	0.1635
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR

ENERGY SAVINGS/730/PEAK SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.5210	0.5499	0.5209	0.7387
Feb	0.6027	0.5513	0.6271	0.6163
Mar	0.4921	0.5541	0.5741	0.8868
Apr	0.4628	0.5713	0.5095	0.5560
May	0.3427	1.3789	0.2514	0.6345
Jun	0.3094	0.7109	1.0736	0.6015
Jul	0.7016	0.7178	0.8455	0.6835
Aug	0.7233	0.6480	0.7922	0.6890
Sep	0.3093	0.6408	0.6835	0.5892
Oct	0.4190	0.3762	0.4438	0.5237
Nov	0.5844	0.4423	0.4734	0.6366
Dec	0.6229	0.4412	0.9254	0.6796
Annual	0.5066	0.5360	0.5750	0.6633

Table 14 Small Retail Demand Factors

Small Retail, existing baseline

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
19.0%	35.6%	13.9%	21.0%

HEAT PUMP SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima

WEIGHTED AVERAGE SEASONALITY FACTOR
CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.1025	0.1019	0.0894	0.1040
Feb	0.0833	0.0816	0.0719	0.0761
Mar	0.0840	0.0824	0.0720	0.0738
Apr	0.0728	0.0729	0.0668	0.0598
May	0.0674	0.0744	0.0744	0.0719
Jun	0.0747	0.0791	0.0932	0.0846
Jul	0.0946	0.0959	0.1171	0.1098
Aug	0.0891	0.0845	0.1043	0.1047
Sep	0.0687	0.0723	0.0811	0.0714
Oct	0.0759	0.0742	0.0685	0.0660
Nov	0.0862	0.0819	0.0737	0.0771
Dec	0.1009	0.0988	0.0876	0.1007
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR
ENERGY SAVINGS/730/PEAK SAVINGS
WEIGHTED AVERAGE SEASONALITY FACTOR

	Missoula	Portland	Salt Lake	Yakima
Jan	1.1393	0.6394	0.7679	1.0530
Feb	0.6741	0.5348	0.7259	0.5582
Mar	0.5930	0.5430	0.6683	0.5477
Apr	0.5865	0.5640	0.6174	0.5679
May	0.5862	0.5596	0.7240	0.3856
Jun	0.3645	0.4488	0.4247	0.3477
Jul	0.4131	0.4462	0.6604	0.4771
Aug	0.3892	0.3695	0.5033	0.4163
Sep	0.7211	0.5549	0.4857	0.4851
Oct	0.6000	0.5277	0.6370	0.5036
Nov	0.6313	0.4946	0.6201	0.6613
Dec	0.7306	0.6553	0.7965	0.6994
Annual	0.5709	0.5174	0.6093	0.5198

Small Retail, new

ELECTRIC SPACE HEAT SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
32.0%	38.1%	29.5%	23.0%

HEAT PUMP SATURATION BY CITY

Missoula	Portland	Salt Lake	Yakima
0.0%	12.3%	21.1%	3.3%

WEIGHTED AVERAGE SEASONALITY FACTOR
CONSERVATION ENERGY SAVINGS

	Missoula	Portland	Salt Lake	Yakima
Jan	0.0662	0.0639	0.0609	0.0641
Feb	0.0597	0.0589	0.0559	0.0577
Mar	0.0680	0.0712	0.0715	0.0687
Apr	0.0770	0.0800	0.0801	0.0815
May	0.0942	0.0965	0.0987	0.0996
Jun	0.1053	0.1021	0.1032	0.1035
Jul	0.1169	0.1108	0.1108	0.1078
Aug	0.1156	0.1069	0.1113	0.1101
Sep	0.0963	0.0969	0.0983	0.0991
Oct	0.0746	0.0847	0.0885	0.0841
Nov	0.0622	0.0645	0.0628	0.0624
Dec	0.0641	0.0637	0.0580	0.0613
TOTAL	1.0000	1.0000	1.0000	1.0000

WEIGHTED AVERAGE CONSERVATION LOAD FACTOR
ENERGY SAVINGS/730/PEAK SAVINGS
WEIGHTED AVERAGE SEASONALITY FACTOR

	Missoula	Portland	Salt Lake	Yakima
Jan	1.0714	0.6556	1.3183	0.9082
Feb	1.0389	0.7632	1.0279	0.9786
Mar	0.8306	1.6997	1.2329	0.9679
Apr	1.0886	1.5991	1.2133	1.3594
May	1.5377	0.5732	1.0160	0.5803
Jun	0.5946	0.5999	0.6636	0.6434
Jul	0.6566	0.6036	0.6294	0.6796
Aug	0.6892	0.5673	0.6743	0.6116
Sep	1.3342	0.5684	0.6941	0.6516
Oct	1.4045	1.9071	1.4952	1.1665
Nov	1.1060	0.7114	0.8885	0.7995
Dec	0.9533	0.6155	0.6896	0.8772
Annual	0.9073	0.7226	0.8533	0.7691

5. INDUSTRIAL SECTOR

5.1. Industrial ECMs

Industrial end-use analysis was conducted initially by Gail Katz, Momentum Engineering for RAMPP-1. Results were updated, specifically for UP&L territory, using various consultant's reports. End-uses in this sector were assigned on the basis on processes. Thus, energy usage was noted for a process, such as air compressors or pumping, not as motors, which are used in both cases. Energy usage is expressed differently for this sector. The econometric forecast supplies gross megawatthour sales without distinction between new and old facilities. Instead of computing the cost of each ECM, we estimated how much savings were possible for a specific average cost. Thus, the industrial supply curve shows only three large step increases. Given the lack of resolution for this sector, we did not see value in trying to be more specific.

The industrial cost supply estimate is based on the following:

1. The 1990 industrial energy consumption by two digit Standard Industrial Classification (SIC) for the service territories of the Company in a six state region.

2. An energy use breakdown by end use from data from the Bonneville Power Administration (BPA), Industrial Test Program (ITP), a series of reports on energy use and conservation in different industries prepared by the Oregon Department of Energy (ODOE) Planning Division, the energy use breakdown in the Dun and Bradstreet database, and energy audit from contractor's reports.

These data were modified to reflect industries in the territories served by the Company. For example, primary metals (SIC 33) appears as a significant industry in the Oregon service territory. Regional energy use data for this SIC is heavily weighted towards the aluminum industry while national energy use data is heavily weighted towards the milling and forming processes found in rolling mills and cable manufacturers. The industries served by Pacific Power in Oregon include several foundries and Teledyne Wah Chang, producing an overall energy profile that looks like a hybrid between a metals fabrication plant and a refining plant.

Other adjustments were made such as increasing the energy use for pumping to allow for plant owned well pumps in light of the predominantly rural nature of the Company Power's service territory. The energy use breakdown focused on the systems where there is known conservation potential.

3. The energy conservation measures were taken from the ITP reports, the ODOE reports, a list of projects submitted through a customized rebate program from an East Coast Utility, and contractor's files.

4. The energy conservation measures were divided into three groups based on the estimated levelized cost (0 to less than 20 mills/kwh, 20 to less than 40 mills/kwh, and 40 to 55 mills/kwh). Several measures were split among different brackets based on the available data. For example, the savings due to

installing a variable speed drive on a pump or fan depends on the operation of the equipment. As a result, this measure will be in the low cost bracket on some equipment and the medium cost bracket on other equipment.

The conservation measures are as follows:

I. Lighting:

A. Incandescent to HPS or metal halide.
B. Mercury to HPS or metal halide.
C. Fluorescent in offices to electronic ballasts.
D. VHO fluorescent to HPS or metal halide.

II. Heating Ventilation and Air Conditioning

A. Install improved controls on office HVAC.
B. Install night shut off on shop plant HVAC.
C. Replace electric unit heaters with radiant heaters.

III. Compressed Air Systems

A. Install multiple compressors for different pressure applications.
B. Install low load unloader mechanisms.
C. Install high efficiency blow-off nozzles.
D. Install multiple compressors with a control system to stage operation.
E. Install high speed electric grinders instead of pneumatic grinders.
F. Install lead-lag control systems for multi-compressor operation to increase part-load compressor for the application.
G. Install humidity controls on air dryers.
H. Rework piping to decrease pressure drop.
I. Install low pressure blowers to replace low pressure application for compressed air.

IV. Pumping Systems

A. Install VSDs on pumping systems.
B. Install multiple staged pumps for applications with varying flow rates.
C. Install controls to stage existing pumps.
D. Use pony motors when loads are relatively constant with occasional peaks.
E. Trim impellers on pumps to match load.
F. Use special nozzles to reduce water use.
G. Increase water recirculation and reuse.

V. Pneumatic Conveying

A. Replace pneumatic conveyors with mechanical conveyors.

VI. Refrigeration

A. Install additional evaporative condensers to minimize condensing pressure.
B. Replace Screw Oil Cooling with thermosyphon.
C. Install staged controls.
D. Install controls for variable suction pressure.
E. Use incoming water for subcooling or precooling.

5.2. Industrial Spreadsheets

Example spreadsheets for each specific industry follow. Figure 12 summarizes potential savings for industrial sector.

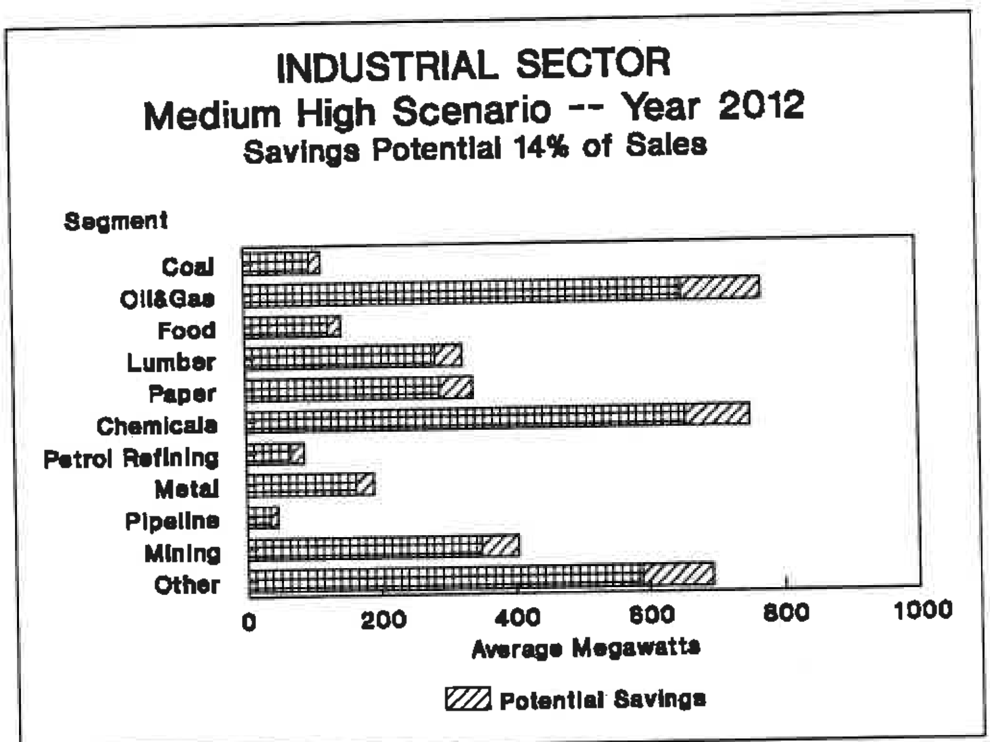


Figure 12 Industrial Savings Potential

FOR THE YEAR: CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

2012

434,473 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN:

03-Feb-92

SOURCE OF DATA FOR SPREADSHEET.

STATE OREGON

SECTOR FOOD

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
AIR COMPRESSORS 1	$0.4038	4.00%	6.00%	1,043	15	100%	100%	0.091	15.370	0.119
AIR COMPRESSORS 2	$0.8075	4.00%	6.00%	1,043	15	100%	100%	0.091	30.740	0.119
AIR COMPRESSORS 3	$0.6056	4.00%	3.00%	521	15	100%	100%	0.091	46.109	0.060
DRYING (ELECTRIC) 1	$0.0000	1.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
DRYING (ELECTRIC) 2	$0.1009	1.00%	3.00%	130	15	100%	100%	0.091	30.740	0.015
DRYING (ELECTRIC) 3	$0.0000	1.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
DRYING (FANS) 1	$0.1009	3.00%	2.00%	261	15	100%	100%	0.091	15.370	0.030
DRYING (FANS) 2	$0.5047	3.00%	5.00%	652	15	100%	100%	0.091	30.740	0.074
DRYING (FANS) 3	$0.4542	3.00%	3.00%	391	15	100%	100%	0.091	46.109	0.045
HVAC 1	$0.1346	2.00%	4.00%	348	15	100%	100%	0.091	15.370	0.040
HVAC 2	$0.1346	2.00%	2.00%	174	15	100%	100%	0.091	30.740	0.020
HVAC 3	$0.4038	2.00%	4.00%	348	15	100%	100%	0.091	46.109	0.040
LIGHTING 1	$0.8412	10.00%	5.00%	2,172	15	100%	100%	0.091	15.370	0.248
LIGHTING 2	$2.6918	10.00%	8.00%	3,476	15	100%	100%	0.091	30.740	0.397
LIGHTING 3	$2.0188	10.00%	4.00%	1,738	15	100%	100%	0.091	46.109	0.198
LOW TEMP REFRIG 1	$2.1198	42.00%	3.00%	5,474	15	100%	100%	0.091	15.370	0.625
LOW TEMP REFRIG 2	$8.4790	42.00%	6.00%	10,949	15	100%	100%	0.091	30.740	1.250
LOW TEMP REFRIG 3	$6.3593	42.00%	3.00%	5,474	15	100%	100%	0.091	46.109	0.625
MED TEMP REFRIG 1	$0.6056	12.00%	3.00%	1,564	15	100%	100%	0.091	15.370	0.179
MED TEMP REFRIG 2	$1.6151	12.00%	4.00%	2,085	15	100%	100%	0.091	30.740	0.238
MED TEMP REFRIG 3	$2.4226	12.00%	4.00%	2,085	15	100%	100%	0.091	46.109	0.238
OTHER PROCESS 1	$1.0599	21.00%	3.00%	2,737	15	100%	100%	0.091	15.370	0.312
OTHER PROCESS 2	$4.9461	21.00%	7.00%	6,387	15	100%	100%	0.091	30.740	0.729
OTHER PROCESS 3	$3.1796	21.00%	3.00%	2,737	15	100%	100%	0.091	46.109	0.312
PUMPS 1	$0.8412	5.00%	10.00%	2,172	15	100%	100%	0.091	15.370	0.248
PUMPS 2	$3.3647	5.00%	20.00%	4,345	15	100%	100%	0.091	30.740	0.496
PUMPS 3	$1.2618	5.00%	5.00%	1,086	15	100%	100%	0.091	46.109	0.124
	$0.0000	0.00%	0.00%	0	0	0%	100%	0.000	0.000	0.000

FOR THE YEAR: CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

2012

2,047,420 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN:

03-Feb-92

SOURCE OF DATA FOR SPREADSHEET.

STATE OREGON

SECTOR LUMBER

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
AIR COMPRESSORS 1	$1.2113	12.00%	6.00%	14,741	15	100%	100%	0.091	15.370	1.683
AIR COMPRESSORS 2	$2.4226	12.00%	6.00%	14,741	15	100%	100%	0.091	30.740	1.683
AIR COMPRESSORS 3	$1.8169	12.00%	3.00%	7,371	15	100%	100%	0.091	46.109	0.841
BOILER AUXILIARIES 1	$0.5047	6.00%	5.00%	6,142	15	100%	100%	0.091	15.370	0.701
BOILER AUXILIARIES 2	$1.6151	6.00%	8.00%	9,828	15	100%	100%	0.091	30.740	1.122
BOILER AUXILIARIES 3	$0.6056	6.00%	2.00%	2,457	15	100%	100%	0.091	45.109	0.280
CHIPPERS 1	$0.0000	8.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
CHIPPERS 2	$0.0000	8.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
CHIPPERS 3	$0.0000	8.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
CONVEYORS 1	$0.0000	8.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
CONVEYORS 2	$0.5384	8.00%	2.00%	3,276	15	100%	100%	0.091	30.740	0.374
CONVEYORS 3	$0.0000	8.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
DRYING (FANS) 1	$0.3365	10.00%	2.00%	4,095	15	100%	100%	0.091	15.370	0.467
DRYING (FANS) 2	$1.3459	10.00%	4.00%	8,190	15	100%	100%	0.091	30.740	0.935
DRYING (FANS) 3	$1.0094	10.00%	2.00%	4,095	15	100%	100%	0.091	46.109	0.467
HVAC 1	$0.0673	1.00%	4.00%	819	15	100%	100%	0.091	15.370	0.093
HVAC 2	$0.0673	1.00%	2.00%	409	15	100%	100%	0.091	30.740	0.047
HVAC 3	$0.2019	1.00%	4.00%	819	15	100%	100%	0.091	46.109	0.093
LIGHTING 1	$0.9253	11.00%	5.00%	11,261	15	100%	100%	0.091	15.370	1.285
LIGHTING 2	$2.9609	11.00%	8.00%	18,017	15	100%	100%	0.091	30.740	2.057
LIGHTING 3	$2.2207	11.00%	4.00%	9,009	15	100%	100%	0.091	46.109	1.028
OTHER PROCESS 1	$1.5141	30.00%	3.00%	18,427	15	100%	100%	0.091	15.370	2.104
OTHER PROCESS 2	$7.0659	30.00%	7.00%	42,996	15	100%	100%	0.091	30.740	4.908
OTHER PROCESS 3	$0.0000	30.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
PNEUMATIC CONVEYING 1	$2.0188	8.00%	15.00%	24,569	15	100%	100%	0.091	15.370	2.805
PNEUMATIC CONVEYING 2	$4.0376	8.00%	15.00%	24,569	15	100%	100%	0.091	30.740	2.805
PNEUMATIC CONVEYING 3	$0.8075	8.00%	2.00%	3,276	15	100%	100%	0.091	46.109	0.374
POLLUTION CONTROL 1	$0.0505	3.00%	1.00%	614	15	100%	100%	0.091	15.370	0.070
POLLUTION CONTROL 2	$0.1009	3.00%	1.00%	614	15	100%	100%	0.091	30.740	0.070
PUMPS 1	$0.5047	3.00%	10.00%	6,142	15	100%	100%	0.091	15.370	0.701

FOR THE YEAR: CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

2012

2,257,979 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN:

03-Feb-92

SOURCE OF DATA FOR SPREADSHEET:

STATE OREGON

SECTOR PAPER

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
AIR COMPRESSORS 1	$0.3028	3.00%	6.00%	4,064	15	100%	100%	0.091	15.370	0.464
AIR COMPRESSORS 2	$0.8075	3.00%	8.00%	5,419	15	100%	100%	0.091	30.740	0.619
AIR COMPRESSORS 3	$0.4542	3.00%	3.00%	2,032	15	100%	100%	0.091	46.109	0.232
BOILER AUXILIARIES 1	$0.1346	2.00%	4.00%	1,806	15	100%	100%	0.091	15.370	0.206
BOILER AUXILIARIES 2	$0.2692	2.00%	4.00%	1,806	15	100%	100%	0.091	30.740	0.206
BOILER AUXILIARIES 3	$0.2019	2.00%	2.00%	903	15	100%	100%	0.091	46.109	0.103
DRYING (FANS) 1	$0.0000	8.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
DRYING (FANS) 2	$1.3459	8.00%	5.00%	9,032	15	100%	100%	0.091	30.740	1.031
HVAC 1	$0.0673	1.00%	4.00%	903	15	100%	100%	0.091	15.370	0.103
HVAC 2	$0.0673	1.00%	2.00%	452	15	100%	100%	0.091	30.740	0.052
HVAC 3	$0.2019	1.00%	4.00%	903	15	100%	100%	0.091	46.109	0.103
LIGHTING 1	$0.1682	2.00%	5.00%	2,258	15	100%	100%	0.091	15.370	0.258
LIGHTING 2	$0.5384	2.00%	8.00%	3,613	15	100%	100%	0.091	30.740	0.412
LIGHTING 3	$0.4038	2.00%	4.00%	1,806	15	100%	100%	0.091	46.109	0.206
OTHER FANS 1	$0.3365	5.00%	4.00%	4,516	15	100%	100%	0.091	15.370	0.516
OTHER FANS 2	$1.3459	5.00%	8.00%	9,032	15	100%	100%	0.091	30.740	1.031
OTHER FANS 3	$2.0188	5.00%	8.00%	9,032	15	100%	100%	0.091	46.109	1.031
OTHER PROCESS	$5.2994	45.00%	7.00%	71,126	15	100%	100%	0.091	15.370	8.119
OTHER PROCESS 1	$4.5423	45.00%	3.00%	30,483	15	100%	100%	0.091	30.740	3.480
OTHER PROCESS 3	$6.8135	45.00%	3.00%	30,483	15	100%	100%	0.091	46.109	3.480
PNEUMATIC CONVEYING 1	$0.5047	2.00%	15.00%	6,774	15	100%	100%	0.091	15.370	0.773
PNEUMATIC CONVEYING 2	$1.0094	2.00%	15.00%	6,774	15	100%	100%	0.091	30.740	0.773
PNEUMATIC CONVEYING 3	$0.2019	2.00%	2.00%	903	15	100%	100%	0.091	46.109	0.103
POLLUTION CONTROL 1	$0.0505	3.00%	1.00%	677	15	100%	100%	0.091	15.370	0.077
POLLUTION CONTROL 2	$0.0000	3.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
PUMPS 1	$2.6918	16.00%	10.00%	36,128	15	100%	100%	0.091	15.370	4.124
PUMPS 2	$10.7670	16.00%	20.00%	72,255	15	100%	100%	0.091	30.740	8.248
PUMPS 3	$4.0376	16.00%	5.00%	18,064	15	100%	100%	0.091	46.109	2.062
REFINING 1	$0.0000	13.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
REFINING 2	$4.3741	13.00%	10.00%	29,354	15	100%		0.091	30.740	0.000

FOR THE YEAR: CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

2012

533,846 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN:

03-Feb-92

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON	
SECTOR	METAL	
REAL DISCOUNT RATE		4.22%
INFLATION RATE		5.10%
FUEL INFLATION RATE		0.00%
EFFECTIVE DISCOUNT RATE		4.22%
NOMINAL INFLATION RATE		9.54%

CONSERVATION MEASURE	FIRST COST (K$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
AIR COMPRESSORS 1	$1.0094	10.00%	6.00%	3,203	15	100%	100%	0.091	15.370	0.366
AIR COMPRESSORS 2	$2.0188	10.00%	6.00%	3,203	15	100%	100%	0.091	30.740	0.366
AIR COMPRESSORS 3	$1.5141	10.00%	3.00%	1,602	15	100%	100%	0.091	46.110	0.183
ARC FURNACES 1	$0.2692	8.00%	2.00%	854	15	100%	100%	0.091	15.370	0.098
ARC FURNACES 2	$4.0376	8.00%	15.00%	6,406	15	100%	100%	0.091	30.740	0.731
ARC FURNACES 3	$0.0000	8.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
HEAT TREAT 1	$0.2692	4.00%	4.00%	854	15	100%	100%	0.091	15.370	0.098
HEAT TREAT 2	$0.2692	4.00%	2.00%	427	15	100%	100%	0.091	30.740	0.049
HEAT TREAT 3	$0.0000	4.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
HVAC 1	$0.1346	2.00%	4.00%	427	15	100%	100%	0.091	15.370	0.049
HVAC 2	$0.1346	2.00%	2.00%	214	15	100%	100%	0.091	30.740	0.024
HVAC 3	$0.4038	2.00%	4.00%	427	15	100%	100%	0.091	46.110	0.049
INDUCTION FURNACES 1	$0.6561	13.00%	3.00%	2,082	15	100%	100%	0.091	15.370	0.238
INDUCTION FURNACES 2	$7.8734	13.00%	18.00%	12,492	15	100%	100%	0.091	30.740	1.426
INDUCTION FURNACES 3	$0.0000	13.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
LIGHTING 1	$0.4206	5.00%	5.00%	1,335	15	100%	100%	0.091	15.370	0.152
LIGHTING 2	$1.3459	5.00%	8.00%	2,135	15	100%	100%	0.091	30.740	0.244
LIGHTING 3	$1.0094	5.00%	4.00%	1,068	15	100%	100%	0.091	46.110	0.122
OTHER PROCESS 1	$2.2712	45.00%	3.00%	7,207	15	100%	100%	0.091	15.370	0.823
OTHER PROCESS 2	$10.5988	45.00%	7.00%	16,816	15	100%	100%	0.091	30.740	1.920
OTHER PROCESS 3	$6.8137	45.00%	3.00%	7,207	15	100%	100%	0.091	46.110	0.823
POLLUTION CONTROL 1	$0.3533	7.00%	3.00%	1,121	15	100%	100%	0.091	15.370	0.128
POLLUTION CONTROL 2	$0.0000	7.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
POLLUTION CONTROL 3	$5.2995	7.00%	15.00%	5,605	15	100%	100%	0.091	46.110	0.640
PUMPS 1	$1.0094	6.00%	10.00%	3,203	15	100%	100%	0.091	15.370	0.366
PUMPS 2	$4.0376	6.00%	20.00%	6,406	15	100%	100%	0.091	30.740	0.731
PUMPS 3	$1.5141	6.00%	5.00%	1,602	15	100%	100%	0.091	46.110	0.183

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

1,005,504 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN: 03-Feb-92

SOURCE OF DATA FOR SPREADSHEET:

STATE	OREGON
SECTOR	OTHER
REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
AIR COMPRESSORS 1	$0.7325	8.00%	6.00%	4,826	15	100%	100%	0.091	13.941	0.551
AIR COMPRESSORS 2	$1.4649	8.00%	6.00%	4,826	15	100%	100%	0.091	27.882	0.551
AIR COMPRESSORS 3	$1.0987	8.00%	3.00%	2,413	15	100%	100%	0.091	41.823	0.275
HVAC 1	$0.1221	2.00%	4.00%	804	15	100%	100%	0.091	13.941	0.092
HVAC 2	$0.1221	2.00%	2.00%	402	15	100%	100%	0.091	27.882	0.046
HVAC 3	$0.3662	2.00%	4.00%	804	15	100%	100%	0.091	41.823	0.092
LIGHTING 1	$0.7630	10.00%	5.00%	5,028	15	100%	100%	0.091	13.941	0.574
LIGHTING 2	$2.4415	10.00%	8.00%	8,044	15	100%	100%	0.091	27.882	0.918
LIGHTING 3	$1.8311	10.00%	4.00%	4,022	15	100%	100%	0.091	41.823	0.459
OTHER PROCESS 1	$3.2960	72.00%	3.00%	21,719	15	100%	100%	0.091	13.941	2.479
OTHER PROCESS 2	$15.3815	72.00%	7.00%	50,677	15	100%	100%	0.091	27.882	5.785
OTHER PROCESS 3	$9.8881	72.00%	3.00%	21,719	15	100%	100%	0.091	41.823	2.479
PUMPS 1	$1.2208	8.00%	10.00%	8,044	15	100%	100%	0.091	13.941	0.918
PUMPS 2	$4.8830	8.00%	20.00%	16,088	15	100%	100%	0.091	27.882	1.837
PUMPS 3	$1.8311	8.00%	5.00%	4,022	15	100%	100%	0.091	41.823	0.459

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

504,111 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN: 03-Feb-92

SOURCE OF DATA FOR SPREADSHEET:

STATE UTAH

SECTOR COAL

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	—	---	---	---	---	---	---	---	0.000	0.000
LIGHTING1	$0.2524	3.00%	5.00%	756	15	100%	100%	0.091	15.370	0.086
LIGHTING2	$0.5047	3.00%	5.00%	756	15	100%	100%	0.091	30.740	0.086
LIGHTING3	$0.6056	3.00%	4.00%	605	15	100%	100%	0.091	46.109	0.069
HVAC1	$1.3459	10.00%	8.00%	4,033	15	100%	100%	0.091	15.370	0.460
HVAC2	$1.3459	10.00%	4.00%	2,016	15	100%	100%	0.091	30.740	0.230
HVAC3	$4.0376	10.00%	8.00%	4,033	15	100%	100%	0.091	46.109	0.460
AIR COMPRESSOR1	$2.3216	23.00%	6.00%	6,957	15	100%	100%	0.091	15.370	0.794
AIR COMPRESSOR2	$4.6433	23.00%	6.00%	6,957	15	100%	100%	0.091	30.740	0.794
AIR COMPRESSOR3	$3.4825	23.00%	3.00%	3,478	15	100%	100%	0.091	46.109	0.397
PUMPS1	$1.0767	8.00%	8.00%	3,226	15	100%	100%	0.091	15.370	0.368
PUMPS2	$2.6918	8.00%	10.00%	4,033	15	100%	100%	0.091	30.740	0.460
PUMPS3	$2.0188	8.00%	5.00%	2,016	15	100%	100%	0.091	46.109	0.230
CONVEYORS1	$3.1292	31.00%	6.00%	9,376	15	100%	100%	0.091	15.370	1.070
CONVEYORS2	$5.2153	31.00%	5.00%	7,814	15	100%	100%	0.091	30.740	0.892
CONVEYORS3	$4.6938	31.00%	3.00%	4,688	15	100%	100%	0.091	46.109	0.535
DRIVEPOWER1	$0.6056	9.00%	4.00%	1,815	15	100%	100%	0.091	15.370	0.207
DRIVEPOWER2	$0.9085	9.00%	3.00%	1,361	15	100%	100%	0.091	30.740	0.155
DRIVEPOWER3	$1.3627	9.00%	3.00%	1,361	15	100%	100%	0.091	46.109	0.155
OTHER PROCESS1	$1.0767	16.00%	4.00%	3,226	15	100%	100%	0.091	15.370	0.368
OTHER PROCESS2	$1.6151	16.00%	3.00%	2,420	15	100%	100%	0.091	30.740	0.276
OTHER PROCESS3	$2.4226	16.00%	3.00%	2,420	15	100%	100%	0.091	46.109	0.276

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

174,331 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN: 03-Feb-92

SOURCE OF DATA FOR SPREADSHEET

STATE UTAH

SECTOR OIL&GAS

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
WELL PUMPS1	$2.0188	30.00%	4.00%	2,092	15	100%	100%	0.091	15.370	0.239
WELL PUMPS2	$6.0565	30.00%	6.00%	3,138	15	100%	100%	0.091	30.740	0.358
WELL PUMPS3	$4.5424	30.00%	3.00%	1,569	15	100%	100%	0.091	46.110	0.179
REINJECTION PUMPS1	$3.5329	30.00%	7.00%	3,661	15	100%	100%	0.091	15.370	0.418
REINJECTION PUMPS2	$12.1129	30.00%	12.00%	6,276	15	100%	100%	0.091	30.740	0.716
REINJECTION PUMPS3	$7.5707	30.00%	5.00%	2,615	15	100%	100%	0.091	46.110	0.299
GAS COMPRESSORS1	$0.2524	5.00%	3.00%	261	15	100%	100%	0.091	15.370	0.030
GAS COMPRESSORS2	$1.0094	5.00%	6.00%	523	15	100%	100%	0.091	30.740	0.060
GAS COMPRESSORS3	$0.7571	5.00%	3.00%	261	15	100%	100%	0.091	46.110	0.030
OTHER PROCESS1	$1.7665	35.00%	3.00%	1,830	15	100%	100%	0.091	15.370	0.209
OTHER PROCESS2	$5.8882	35.00%	5.00%	3,051	15	100%	100%	0.091	30.740	0.348
OTHER PROCESS3	$5.2995	35.00%	3.00%	1,830	15	100%	100%	0.091	46.110	0.209

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

2,011,857 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN: 03-Feb-92

SOURCE OF DATA FOR SPREADSHEET.

STATE UTAH

SECTOR CHEMICALS

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
AIR COMPRESSORS 1	$3.5121	35.90%	6.00%	43,335	15	100%	100%	0.091	14.896	4.947
AIR COMPRESSORS 2	$7.0241	35.90%	6.00%	43,335	15	100%	100%	0.091	29.792	4.947
AIR COMPRESSORS 3	$5.2681	35.90%	3.00%	21,668	15	100%	100%	0.091	44.688	2.473
DRYING (FANS) 1	$0.1826	5.60%	2.00%	2,253	15	100%	100%	0.091	14.896	0.257
DRYING (FANS) 2	$0.9131	5.60%	5.00%	5,633	15	100%	100%	0.091	29.792	0.643
DRYING (FANS) 3	$2.4653	5.60%	9.00%	10,140	15	100%	100%	0.091	44.688	1.158
ELECTROCHEMICAL 1	$0.0000	52.20%	0.00%	0	15	100%	100%	0.091	0.000	0.000
ELECTROCHEMICAL 2	$8.5111	52.20%	5.00%	52,509	15	100%	100%	0.091	29.792	5.994
ELECTROCHEMICAL 3	$0.0000	52.20%	0.00%	0	15	100%	100%	0.091	0.000	0.000
HVAC 1	$0.0261	0.40%	4.00%	322	15	100%	100%	0.091	14.896	0.037
HVAC 2	$0.0261	0.40%	2.00%	161	15	100%	100%	0.091	29.792	0.018
HVAC 3	$0.0783	0.40%	4.00%	322	15	100%	100%	0.091	44.688	0.037
LIGHTING 1	$0.1223	1.50%	5.00%	1,509	15	100%	100%	0.091	14.896	0.172
LIGHTING 2	$0.3913	1.50%	8.00%	2,414	15	100%	100%	0.091	29.792	0.276
LIGHTING 3	$0.3669	1.50%	5.00%	1,509	15	100%	100%	0.091	44.688	0.172
DRIVEPOWER1	$0.4500	9.20%	3.00%	5,553	15	100%	100%	0.091	14.896	0.634
DRIVEPOWER2	$2.1001	9.20%	7.00%	12,956	15	100%	100%	0.091	29.792	1.479
DRIVEPOWER3	$1.3500	9.20%	3.00%	5,553	15	100%	100%	0.091	44.688	0.634
POLLUTION CONTROL 1	$0.0098	0.60%	1.00%	121	15	100%	100%	0.091	14.896	0.014
POLLUTION CONTROL 2	$0.0000	0.60%	0.00%	0	15	100%	100%	0.091	0.000	0.000
POLLUTION CONTROL 3	$0.0000	0.60%	0.00%	0	15	100%	100%	0.091	0.000	0.000
PUMPS 1	$0.1794	1.10%	10.00%	2,213	15	100%	100%	0.091	14.896	0.253
PUMPS 2	$0.7174	1.10%	20.00%	4,426	15	100%	100%	0.091	29.792	0.505
PUMPS 3	$0.2690	1.10%	5.00%	1,107	15	100%	100%	0.091	44.688	0.126
AGITATION 1	$0.0000	0.20%	0.00%	0	15	100%	100%	0.091	0.000	0.000
AGITATION 2	$0.0261	0.20%	4.00%	161	15	100%	100%	0.091	29.792	0.018
AGITATION 3	$0.1467	0.20%	15.00%	604	15	100%	100%	0.091	44.688	0.069

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

372,422 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN: 03-Feb-92

SOURCE OF DATA FOR SPREADSHEET:

STATE UTAH

SECTOR PETROL

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
AIR COMPRESSORS 1	$0.3028	3.00%	6.00%	670	15	100%	100%	0.091	15.370	0.077
AIR COMPRESSORS 2	$0.6056	3.00%	6.00%	670	15	100%	100%	0.091	30.740	0.077
AIR COMPRESSORS 3	$0.4542	3.00%	3.00%	335	15	100%	100%	0.091	46.110	0.038
DRYING (FANS) 1	$0.3028	9.00%	2.00%	670	15	100%	100%	0.091	15.370	0.077
DRYING (FANS) 2	$1.5141	9.00%	5.00%	1,676	15	100%	100%	0.091	30.740	0.191
DRYING (FANS) 3	$4.0882	9.00%	9.00%	3,017	15	100%	100%	0.091	46.110	0.344
HVAC 1	$0.2019	3.00%	4.00%	447	15	100%	100%	0.091	15.370	0.051
HVAC 2	$0.2019	3.00%	2.00%	223	15	100%	100%	0.091	30.740	0.026
HVAC 3	$0.6057	3.00%	4.00%	447	15	100%	100%	0.091	46.110	0.051
LIGHTING 1	$0.5888	7.00%	5.00%	1,303	15	100%	100%	0.091	15.370	0.149
LIGHTING 2	$1.8842	7.00%	8.00%	2,086	15	100%	100%	0.091	30.740	0.238
LIGHTING 3	$1.4132	7.00%	4.00%	1,043	15	100%	100%	0.091	46.110	0.119
OTHER PROCESS 1	$1.0094	20.00%	3.00%	2,235	15	100%	100%	0.091	15.370	0.255
OTHER PROCESS 2	$4.7106	20.00%	7.00%	5,214	15	100%	100%	0.091	30.740	0.595
OTHER PROCESS 3	$3.0283	20.00%	3.00%	2,235	15	100%	100%	0.091	46.110	0.255
POLLUTION CONTROL 1	$0.0841	5.00%	1.00%	186	15	100%	100%	0.091	15.370	0.021
POLLUTION CONTROL 2	$0.0000	5.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
POLLUTION CONTROL 3	$0.0000	5.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
PUMPS 1	$7.5706	45.00%	10.00%	16,759	15	100%	100%	0.091	15.370	1.913
PUMPS 2	$30.2823	45.00%	20.00%	33,518	15	100%	100%	0.091	30.740	3.826
PUMPS 3	$11.3561	45.00%	5.00%	8,379	15	100%	100%	0.091	46.110	0.957
AGITATION 1	$0.0000	8.00%	0.00%	0	15	100%	100%	0.091	0.000	0.000
AGITATION 2	$1.0767	8.00%	4.00%	1,192	15	100%	100%	0.091	30.740	0.136
AGITATION 3	$6.0566	8.00%	15.00%	4,469	15	100%	100%	0.091	46.110	0.510

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

396,836 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN: 03-Feb-92

SOURCE OF DATA FOR SPREADSHEET:

STATE UTAH

SECTOR PIPELINE

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
PUMPS1	$23.9723	95.00%	15.00%	56,549	15	100%	100%	0.091	15.369	6.455
PUMPS2	$15.9825	95.00%	5.00%	18,850	15	100%	100%	0.091	30.740	2.152
PUMPS3	$23.9735	95.00%	5.00%	18,850	15	100%	100%	0.091	46.109	2.152
OTHER1	$0.2523	5.00%	3.00%	595	15	100%	100%	0.091	15.367	0.068
OTHER2	$1.1777	5.00%	7.00%	1,389	15	100%	100%	0.091	30.741	0.159
OTHER3	$0.7571	5.00%	3.00%	595	15	100%	100%	0.091	46.112	0.068

FOR THE YEAR: 2012

CONSERVATION SUPPLY PLANNING SPREADSHEET- INDUSTRIAL

2,108,438 TOTAL NUMBER OF MEGAWATTS USED IN SECTOR

DATE OF RUN: 03-Feb-92

SOURCE OF DATA FOR SPREADSHEET:

STATE	UTAH
SECTOR	MINING

REAL DISCOUNT RATE	4.22%
INFLATION RATE	5.10%
FUEL INFLATION RATE	0.00%
EFFECTIVE DISCOUNT RATE	4.22%
NOMINAL INFLATION RATE	9.54%

CONSERVATION MEASURE	FIRST COST (k$/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (MILLS/KWH)	MEASURE SAVING (MWa/YR)
	---	---	---	---	---	---	---	---	0.000	0.000
LIGHTING1	$0.2446	3.00%	5.00%	3,163	15	100%	100%	0.091	14.896	0.361
LIGHTING2	$0.4891	3.00%	5.00%	3,163	15	100%	100%	0.091	29.792	0.361
LIGHTING3	$0.5870	3.00%	4.00%	2,530	15	100%	100%	0.091	44.688	0.289
HVAC1	$0.2609	2.00%	8.00%	3,374	15	100%	100%	0.091	14.896	0.385
HVAC2	$0.2609	2.00%	4.00%	1,687	15	100%	100%	0.091	29.792	0.193
HVAC3	$0.7826	2.00%	8.00%	3,374	15	100%	100%	0.091	44.688	0.385
AIR COMPRESSOR1	$0.1957	2.00%	6.00%	2,530	15	100%	100%	0.091	14.896	0.289
AIR COMPRESSOR2	$0.3913	2.00%	6.00%	2,530	15	100%	100%	0.091	29.792	0.289
AIR COMPRESSOR3	$0.2935	2.00%	3.00%	1,265	15	100%	100%	0.091	44.688	0.144
PUMPS1	$2.4783	19.00%	8.00%	32,048	15	100%	100%	0.091	14.896	3.658
PUMPS2	$6.1958	19.00%	10.00%	40,060	15	100%	100%	0.091	29.792	4.573
PUMPS3	$4.6469	19.00%	5.00%	20,030	15	100%	100%	0.091	44.688	2.287
CONVEYORS1	$0.9783	10.00%	6.00%	12,651	15	100%	100%	0.091	14.896	1.444
CONVEYORS2	$1.6305	10.00%	5.00%	10,542	15	100%	100%	0.091	29.792	1.203
CONVEYORS3	$1.4674	10.00%	3.00%	6,325	15	100%	100%	0.091	44.688	0.722
DRIVEPOWER1	$3.8479	59.00%	4.00%	49,759	15	100%	100%	0.091	14.896	5.680
DRIVEPOWER2	$5.7719	59.00%	3.00%	37,319	15	100%	100%	0.091	29.792	4.260
DRIVEPOWER3	$8.6579	59.00%	3.00%	37,319	15	100%	100%	0.091	44.688	4.260
PROCESS HEAT1	$0.2609	4.00%	4.00%	3,374	15	100%	100%	0.091	14.896	0.385
PROCESS HEAT2	$0.1304	4.00%	1.00%	843	15	100%	100%	0.091	29.792	0.096
PROCESS HEAT3	$0.1957	4.00%	1.00%	843	15	100%	100%	0.091	44.688	0.096
ELECTROCHEMICAL1	$0.2446	3.00%	5.00%	3,163	15	100%	100%	0.091	14.896	0.361
ELECTROCHEMICAL2	$0.3913	3.00%	4.00%	2,530	15	100%	100%	0.091	29.792	0.289
ELECTROCHEMICAL3	$0.5870	3.00%	4.00%	2,530	15	100%	100%	0.091	44.688	0.289

6. OTHER RESOURCES

6.1. Fuel Switching

Fuel switching is defined as replacing the electrical space or water heating equipment in an existing customer's building with fossil fuel fired equipment. Because this reduces the electrical utility load, it can be considered a potential resource. However, because another fuel rather than electricity is still being consumed, it is properly a "load shedding" option rather than energy conservation.

It is important to point out where fuel switching fits in a Least Cost Planning framework. Planning principles require that one look first at low-cost conservation as the first option. Fuel switching can then be considered for the remaining energy consumption. Note that, when examining the cost-effectiveness of the switch, the 10% cost advantage given conservation does not apply to load shedding.

Fuel switching could occur in any customer facility (residential, commercial or industrial) which currently uses electricity to provide heat but could use a fossil fuel instead. In connection with proceedings conducted by Oregon's Department of Energy and the Oregon PUC staff, the Company looked at fuel switching for existing residential customers. The results are typical. The Oregon Department of Energy (ODOE) used a computer model to analyze the energy use of existing homes with electric and fossil fueled forced air furnaces.

An economic calculation sheet computed the comparative economics for the two fuel choices. In this case, the objective was to minimize the Net Present Value (NPV) of the Lifecycle cost. Lifecycle cost includes the initial cost of changing out the equipment, the NPV of operation and maintenance costs, as well as the NPV of fuel cost over a long time period. Results were examined for both a societal and a customer perspective. However, in keeping with Least Cost Planning, the societal perspective was emphasized. This perspective uses the marginal cost (utility avoided cost) of the two fuels in computing lifecycle cost. The NPV of lifecycle cost can also be expressed as a levelized cost for the saved electricity.

The energy consumption model, which is referred to as the "Bin Model," has a manual entitled "A Simplified Energy Analysis Model Incorporating Duct Loss Impacts on Heating System Efficiency." This model is a Lotus 1-2-3 spreadsheet which uses bin weather data to estimate residential heating energy required. It then estimates how much primary energy, fuel or electricity, is required to meet both the heating energy requirement and the heating system duct and system losses. The "Bin Model" allows for explicit analysis of several load factors, envelope area and insulation, floor losses, air infiltration, distribution efficiency and internal heat gains including solar heat through the windows. The equations calculate the flow of heat into and out of a single heated space. Due to assumptions made for these variables, different modelers predict wide variations in energy usage.

Like other engineering models for heating energy estimating, the "Bin Model" does not allow for occupant behavior such as closing off and not heating rooms and turning down the heating thermostat in response to high heating bills. Partly for this reason, engineering models typically over-estimate energy consumption when compared to actual billing data. It is important that the engineering model be "calibrated" or tuned to match typical consumption. To do so, it is necessary to adjust some of the engineering input assumptions to reflect empirical reality.

In spite of these problems, an engineering model is the only available tool for comparing the impact of conservation followed by different heating systems, one electric and the other fossil fuel, in the a prototype home. Using the "Bin Model" it was determined how much electrical energy is avoided and how much gas energy must be purchased.

To determine the cost effectiveness of removing a perfectly good electrical furnace and replacing it with a natural gas furnace, one would need to consider the fixed costs of demolition, the new furnace including flue venting and gas piping, and the variable cost of the purchased natural gas. The avoided cost to the Company for not producing electricity includes avoided generation and a credit for avoided T&D cost but it does not include the 10% allowance for conservation.

The Company has a strong commitment to energy conservation and no customer should be converted to another fuel until all cost effective energy conservation has been installed. Conservation such as added insulation and better windows can reduce the space heating energy usage of electric forced air customers by 2,000 to 3,000 kilowatt-hours.

Considering the costs and benefits itemized by ODOE, a single family prototype home with an existing electric furnace would need to use over 12,000 kilowatt-hours for space heating before it would be cost effective to convert to natural gas.

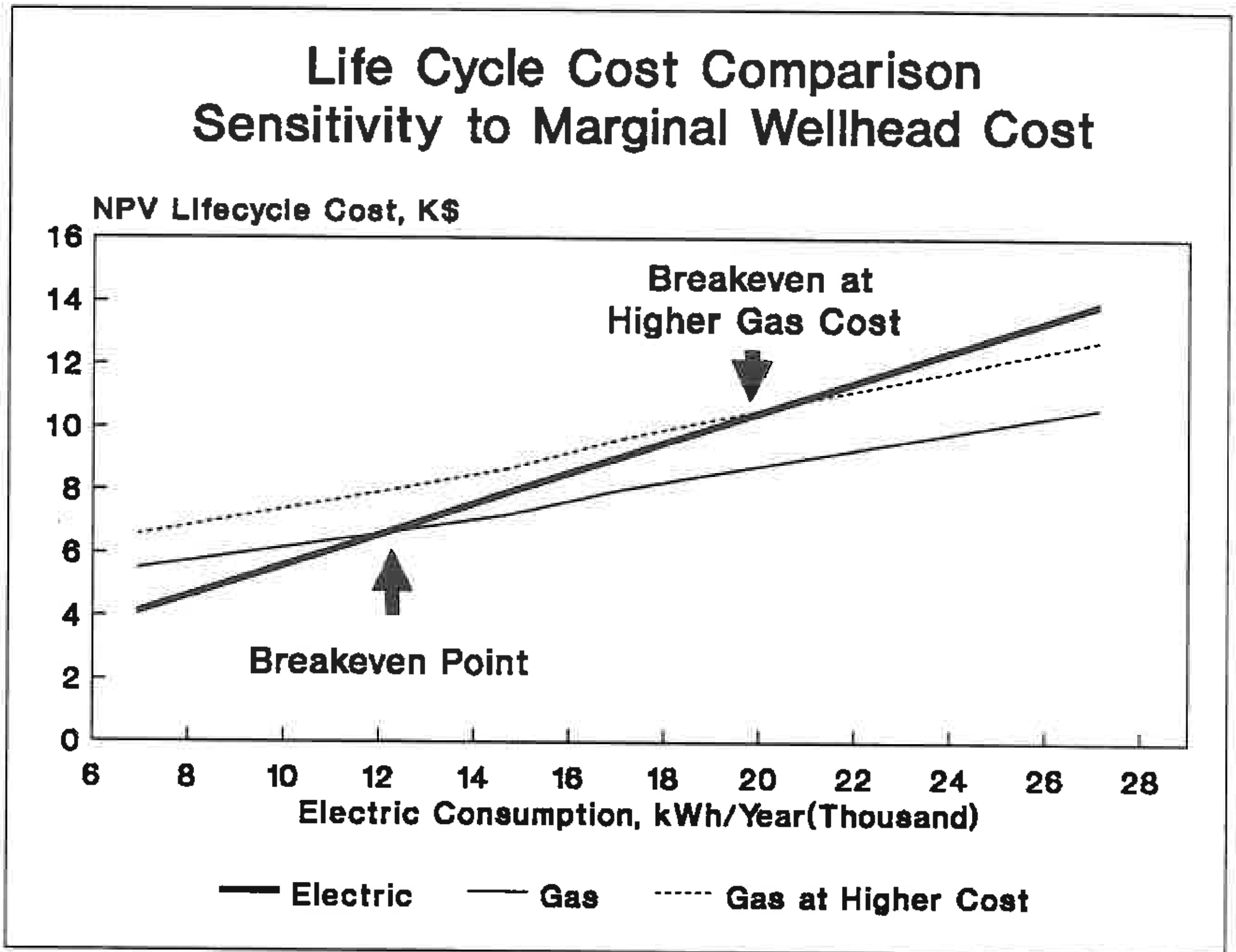


Figure 13 Fuel Switching Breakeven

The economic breakeven point can be determined graphically as shown in Figure 13. This figure shows the NPV of lifecycle cost for the two fuel choices at different levels of energy consumption. The point where the two lines cross over is the economic breakeven point for fuel switching. Note that the lifecycle cost lines for electric and gas are close to being parallel. This implies a high sensitivity to initial assumptions -- a small change in one line can shift the cross-over point dramatically. The figure also shows that the cross-over point would be close to 19,000 kWh if, as the Company has suggested, the marginal cost of gas should be 30% higher at the wellhead.

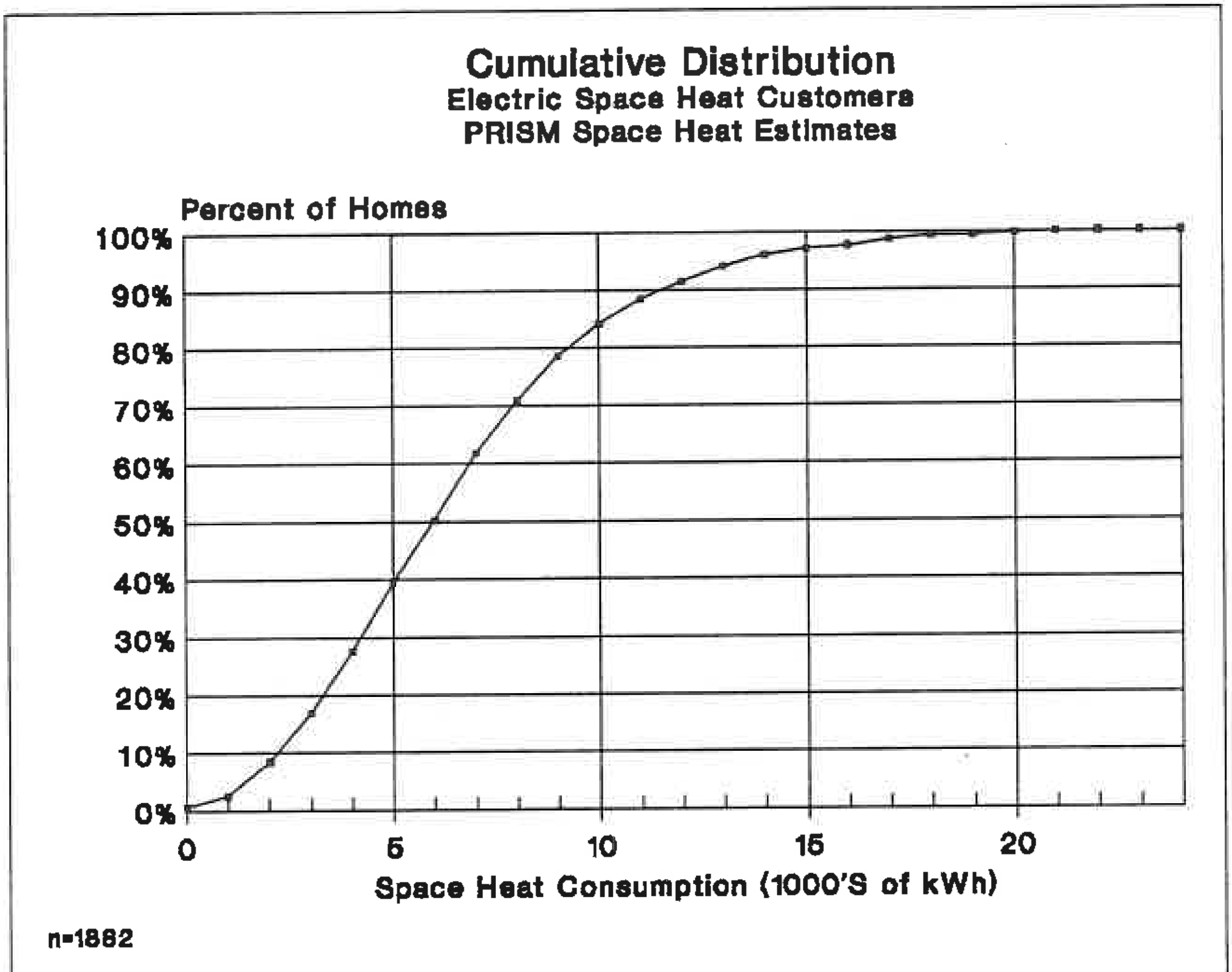


Figure 14 Distribution of Space Heating

Figure 14 shows the distribution of electric space heating energy usage for customers who might be candidates. This distribution is based on 1,882 customers that have electric forced air furnaces, no evidence of wood heat and live where natural gas might be available. As derived from the historical billing data, 92% of these customers use less than 12,000 kilowatt-hours. That means only 8% of the customers would be cost effective for conversion. Assuming that 2,000 to 3,000 kilowatt-hours can be trimmed from the energy usage of these customers by installing energy conservation first, about 5% of customers would still be cost effective candidates for space heat fuel switching. This small number of potential beneficiaries does not justify the development cost of creating a fuel switching program.

Levelized costs for a variety of prototype homes are shown in ?. These prototypes are intended to approximate quintile points of the distribution of the Company's electric space heating customers. The same homes are first weatherized as indicated with "Wx". Note that the Least Cost approach of weatherizing the home first reduces the cost-effectiveness of subsequent fuel switching. Fuel switching as a resource would cost 60 to 100 mills/kWh. For comparison, the Company's levelized avoided cost would be only about 40 mills/kWh.

A similar case can be demonstrated for electric resistance water heating in residential customer homes. The economic cross-over point for water heating is about 4,300 kilowatt-hours per year at a cost of 40 mills/kilowatt-hour, based on recent computations by a Fuel Switching Technical Group. Again energy conservation is the Company's first priority -- water heating savings of 700 to 1,000 kilowatt-hours are possible. This implies that only customers with water heating energy usage over 5,000 kilowatt-hours (homes with large families) would benefit from a fuel switching program. Again the development, marketing, and administrative costs of a full scale fuel switching program for water heating could not be justified.

These results are expected to be similar for other areas of the Company's service territory. Marginal costs for gas are expected to be similar since gas companies are purchasing new supply from the same market. The Company's marginal costs and equipment costs are the same.

Table 15. Fuel Switching Levelized Cost

Usage Level	Electric FAF Annual kWH	Gas FAF Annual MMBTU	Fuel Switch Levelized Cost Mills/kWh
High	17,035	93.53	41
Medium High	11,137	64.44	49
Medium	8,096	53.23	68
Medium Low	6,004	43.54	83
Low	3,490	28.41	124
Wx--High	7,712	46.59	60
Wx--MedHigh	7,091	43.09	63
Wx--Medium	5,441	38.63	89
Wx--MedLow	3,621	28.98	120
Wx--Low	3,490	28.41	124

6.2. Street Lighting

The Company operates a street lighting service in most of its territory. About 98% of street lights in PP&L and 75% in UP&L are owned by the Company. This amounts to about 47,00 lamps in PP&L and 313,000 lamps in UP&L. Older mercury vapor lamps can be replaced by more efficient high pressure sodium (HPS) lamps, saving about 40%. However, the Company has already changed out the majority of its lamps. About 50% of lamps in PP&L and 20% in UP&L remain as mercury vapor lamps. The Company has a policy of retrofiting mercury vapor with HPS during normal maintenance and replacement. Complete changeout of the lamps would result in estimated savings of about 4,500 MWH or about half an average megawatt. Given that the Company already has a policy of replacing the lamps, accelerating the replacement is not a sufficiently large resource to consider as a program opportunity.

6.3. Irrigation

Irrigation savings have been studied in the Northwest for some time. A rough estimate is that 15% from pump efficiency and another 15% from improved scheduling represent the upper end of technical potential. Farm pumps are often worn and mismatched to their applications. Scheduling irrigation to the exact point that crops need it can save water as well as pumping power.

However, there are very serious constraints on the amount of that potential which is achievable. Farmers are highly risk-adverse when it comes to their crops. Although improved scheduling may save water without affecting yields, they are unlikely to be interested in experimenting with their livelihood. Thus, it is difficult to identify opportunities and persuade farmers to participate. In effect these barriers are legitimate transaction costs which need to be considered in developing irrigation conservation supply curves.

For this reason, the reasonable potential for irrigation has not been seriously addressed in this round of planning. The Company will conduct a pilot test of irrigation efficiency in California and use the results to develop a potential estimate for future plans.

7. SUPPLY CURVES

Technical savings potentials from all the sectors are summarized for the supply curves. Examples of the individual and combined curves are shown below. Figure 15 shows the combined supply curves for the medium high forecast. Figure 16 shows the same information for individual sectors on the same chart. Figure 17 shows the combined supply curves for all four forecasts. Figure 18 shows a comparison between the supply curves resulting from new growth and those based on existing building stock. The new growth curves are much larger because they include industrial and appliances.

The next series shows PP&L and UP&L combined under the medium high scenario. Figure 19 shows the supply curve for residential appliances. This curve is very large but represents a lot of savings which remains theoretical, not achievable. Figure 20 shows the industrial supply curve. Figure 21 shows the existing commercial supply curve. Figure 22 shows the new commercial supply curve. Figure 23 shows the potential for space heating in existing residences. Figure 24 shows the same for new residences.

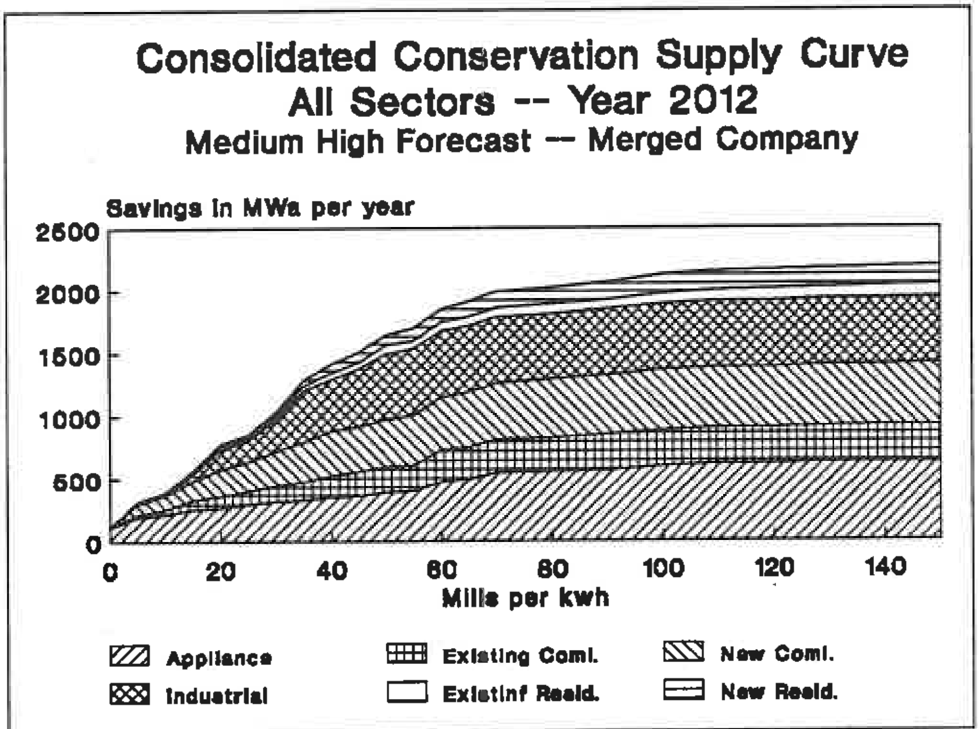


Figure 15 Consolidated Supply Curve

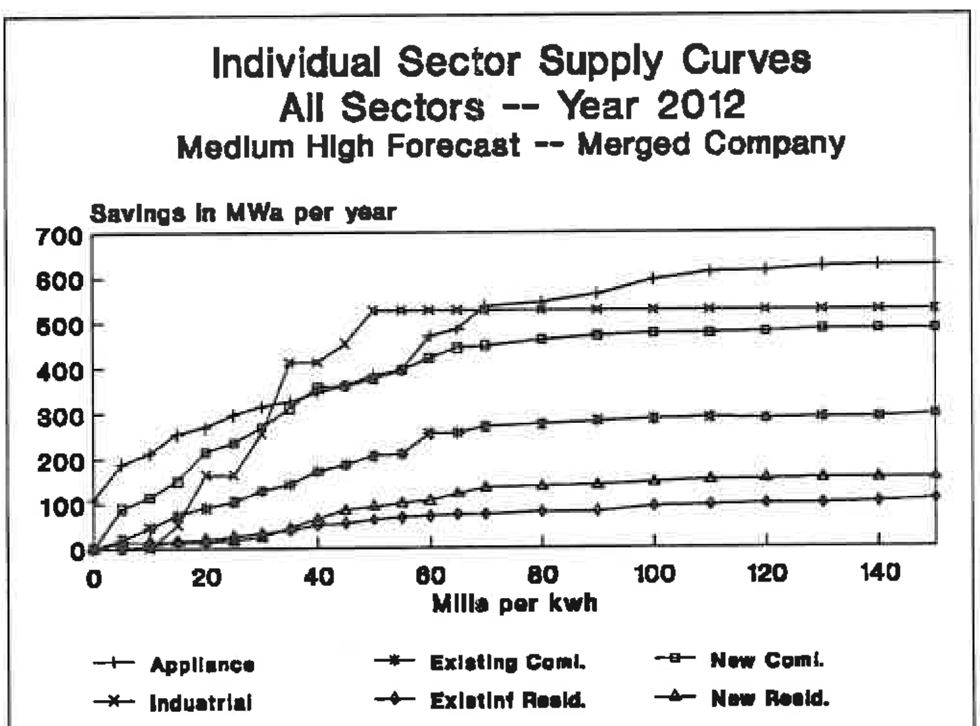


Figure 16 Individual Sector Supply Curves

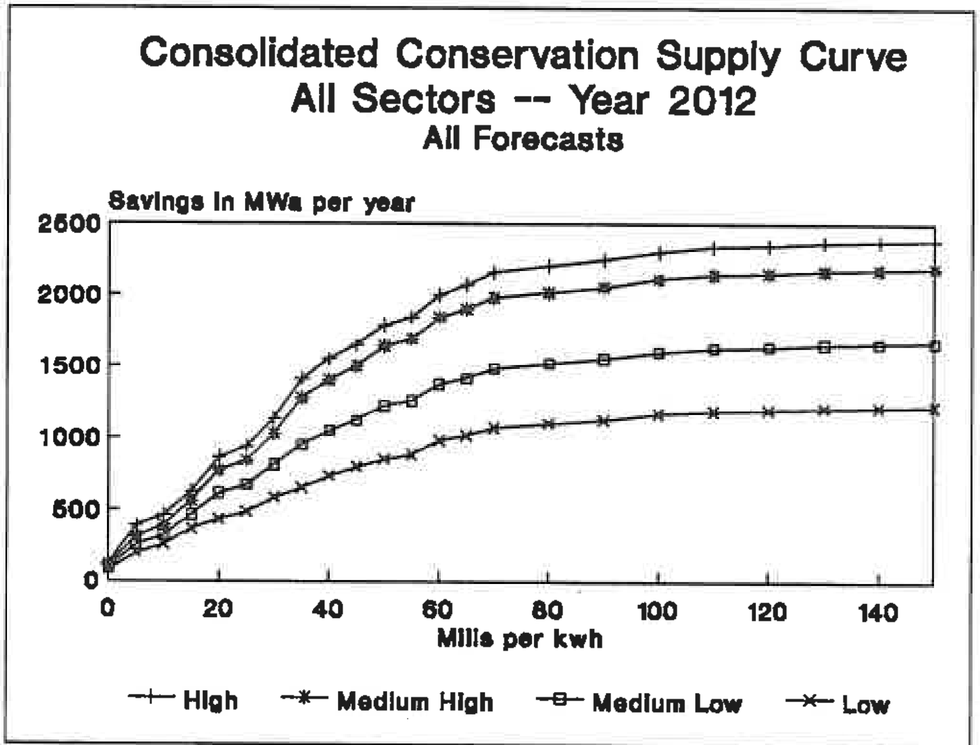


Figure 17 Four Forecast Supply Curve

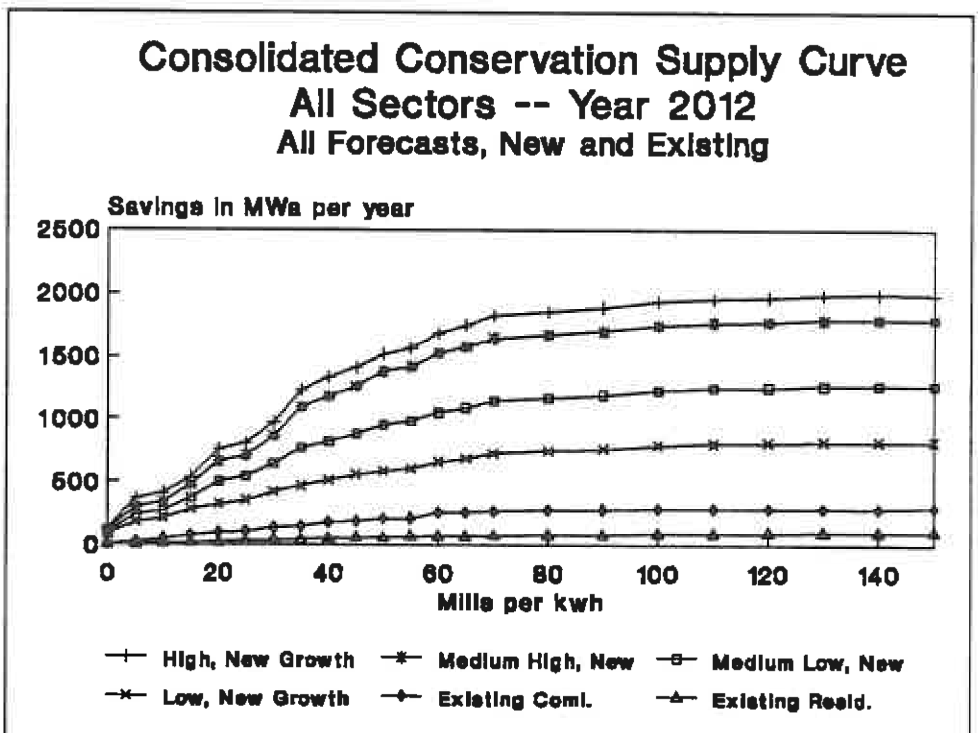


Figure 18 New and Existing Supply Curves

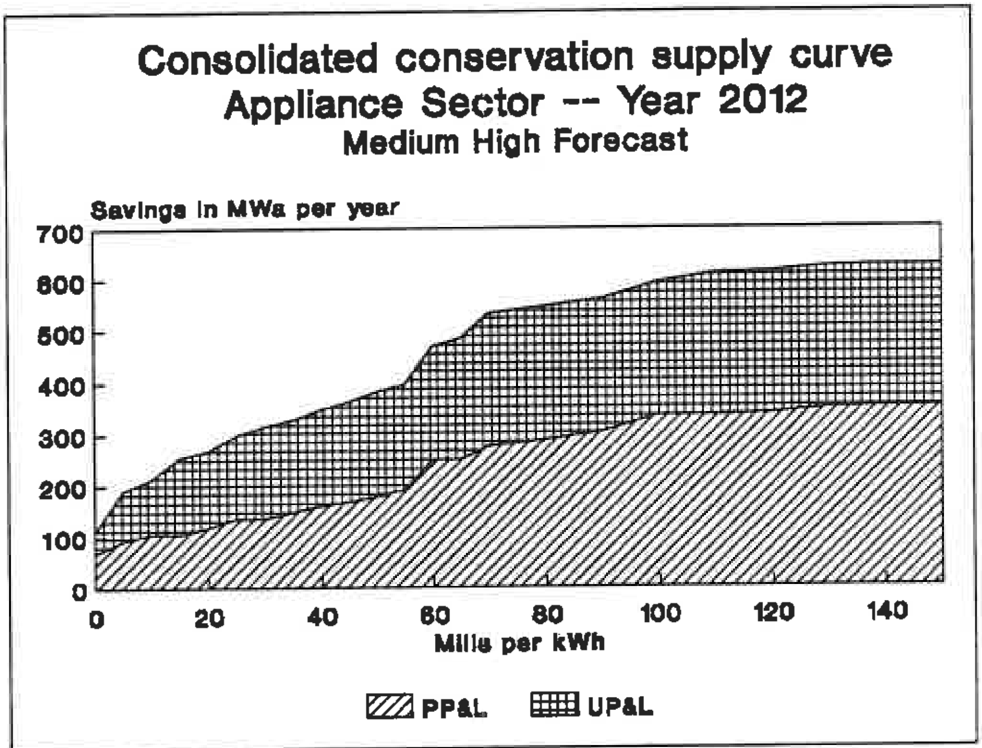


Figure 19 Appliance Supply Curve

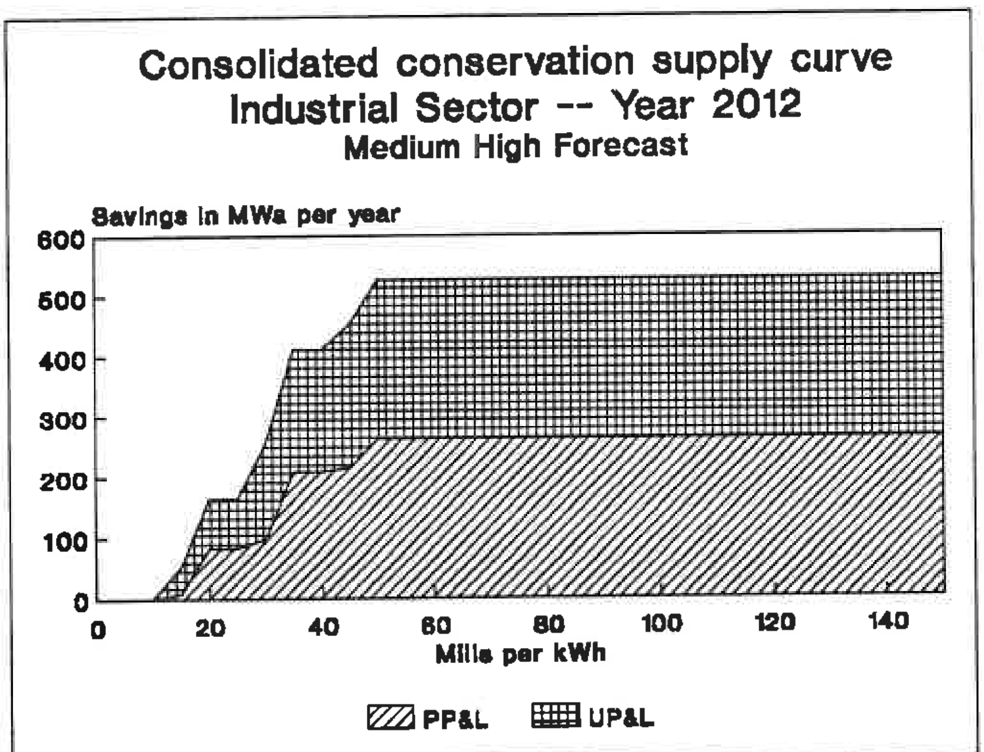


Figure 20 Industrial Supply Curve

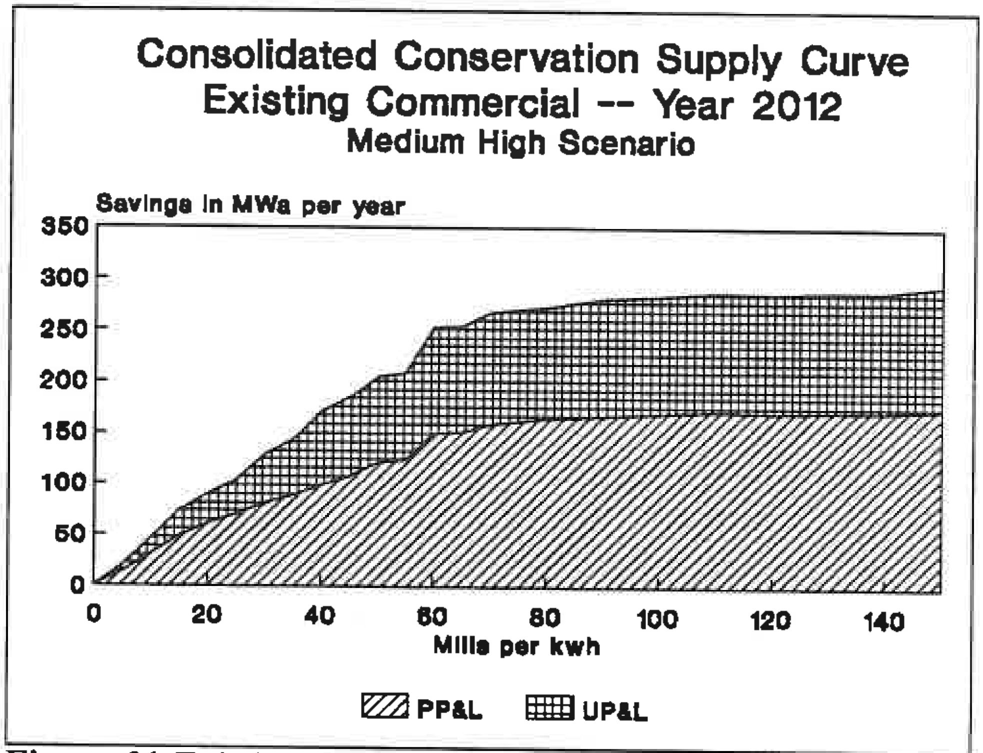


Figure 21 Existing Commercial Supply Curve

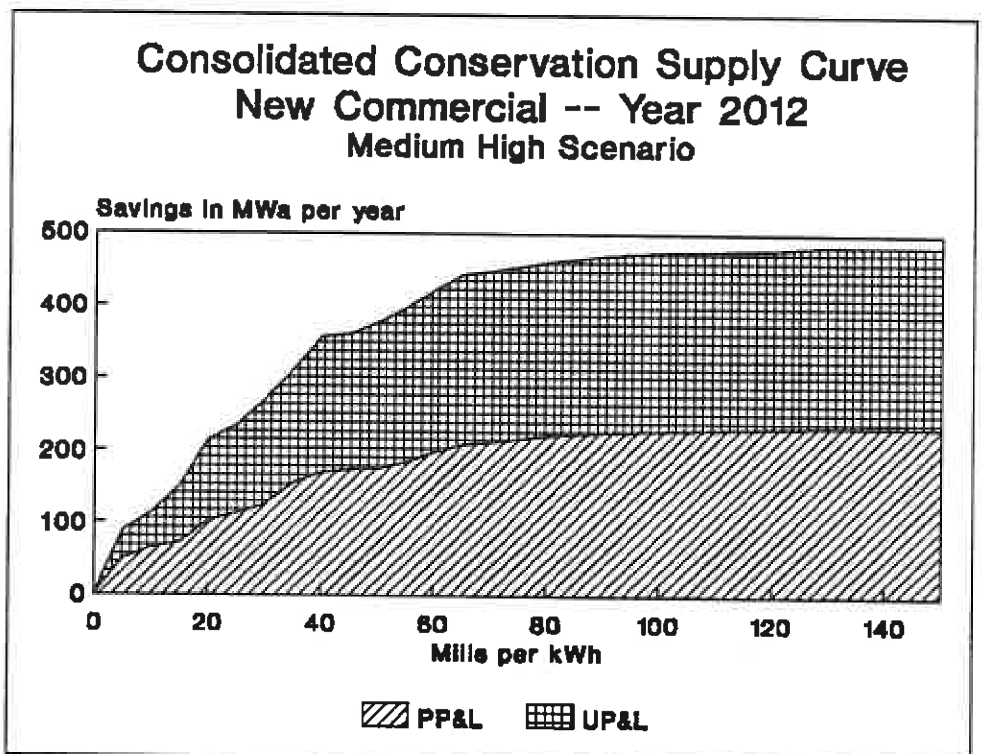


Figure 22 New Commercial Supply Curve

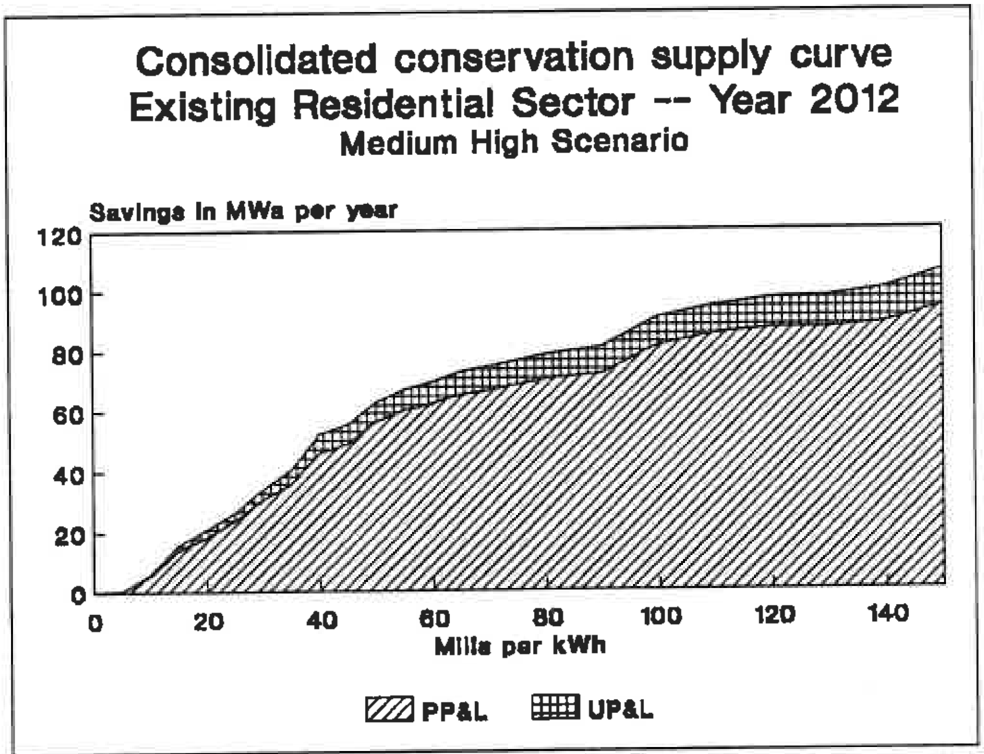


Figure 23 Existing Residential Supply Curve

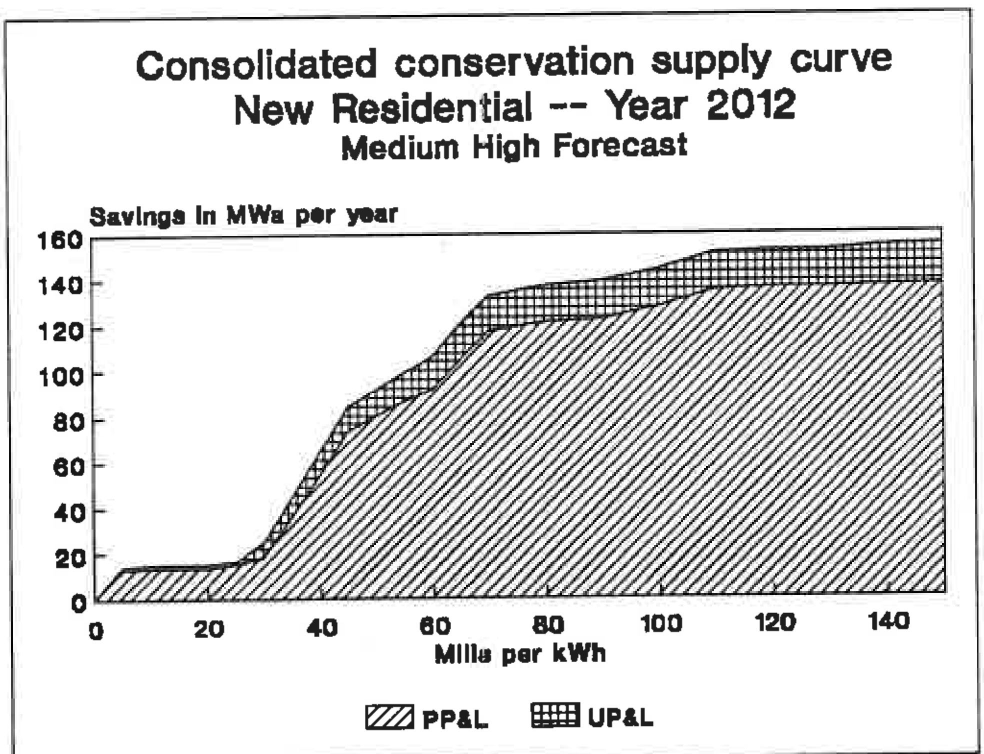


Figure 24 New Residential Supply Curve

Table 16 Technical Potential Compared with NPPC

COMPARISON OF TECHNICAL POTENTIAL
Northwest Power Planning Council vs. Supply Curve Model

	Savings from NPPC High		Savings from RAMPP-2 Supply Curves Med High	
	Savings Fraction	PP&L Share MWa	Savings Fraction	NW States MWa
Commercial Sector				
Existing	.29	120	.40	117
New	.23	92	.25	136
Subtotal	.27	212	.32	253
Residential Sector				
Existing SF	--	18	.31	30
Existing MF	--	8	.13	2
Existing MH	--	--	.21	5
Subtotal Existing	.23	26	.27	37
New SF	--	18	.32	30
New MF	--	3	.00	0
New MH	--	26	.36	30
Subtotal New	.46	47	.32	60
Water Heaters	.35	22	.20	48
Lights	.16	15	.08	21
Subtotal Residential Sector	.01	110	.07	166
Industrial Sector	.07	70	.15	262
GRAND TOTAL ALL SECTORS		392		681

7.1. Comparison with NPPC

The Northwest Power Planning Council (NPPC) has produced the broadest planning document in the Northwest Region. It is difficult to compare technical potential estimates because of the problems isolating the Company from the rest of the Northwest Region. An attempt is made in Table 16. Here the two planning methodologies are compared based on the percentage of savings predicted and the amount of resource estimated for Pacific Power's share of the

Northwest Region. The Company's conservation estimate is larger primarily in estimates of industrial potential. NPPC has a smaller estimate of industrial sales and a smaller estimate of the savings potential for that sector.

8. BACKGROUND CONSERVATION

The forecasts are produced based on "frozen efficiency", that is, without consideration of the amount of conservation customers will do on their own. This amount is removed from the forecast to estimate the load that the company would otherwise have to supply. Thus, the background conservation must also be removed from utility programs to calculate the net cost-effectiveness of the programs. In most cases, the background is small so this is not a serious issue.

Background conservation was assessed by estimating the amount of conservation that customers would perceive as cost-effective based on their retail rates and high implicit discount rate. An implicit discount rate of 60% nominal was used to represent the various customers barriers (it is understood that not all these barriers are financial). Under these conditions only very cheap measures (levelized cost of 8-10 mills/kWh) appear cost-effective. These measures are assumed to be deployed over the twenty year planning horizon.

For residential sector, only ACH improvements on the largest prototype meets the cost-effective criterion. Thus, very little weatherization is expected to occur though the customer's efforts alone. For new construction, MCS absorbs the conservation that people would do on their own. It should be noted that solar access estimates were defined relative to the amount that people would do on their own, so the background has already been accounted for.

For commercial sector, there are many cost-effective measures. Because the existing commercial building stock is in poor shape, there are many appropriate measures. There are also efficiency measures beyond the current code for new

Table 17 Cost Induced Conservation in Forecast

Average Megawatts in year 2012 at 8 mills/KWh or less
Based on Medium High Forecast, Merged Company

Sector	Existing Stock	New Construction	All Stock
Residential	1.1 MWa	0	1.1 MWa
Commercial	64.0	142.3	206.3
Industrial	---	---	---
Total	65.1	142.3	207.4 (10% of potential)

construction which would be cost effective. Thus, there is a certain amount of gravity associated with new commercial construction. The measures applied to background are listed in Table 18. For industrial sector, background efficiency is assumed to be included in the econometric trends embedded in the forecast model.

Although it is only an approximation, consumer barriers can be treated as if they were purely financial. This is done by assuming a high implicit consumer discount rate of about 60% consistent with expected payback observed in consumer market studies. The high discount rate allows the cost-effectiveness calculations to predict the "gravity" amount -- the amount of conservation that people would have done anyway even without a utility program. That amount is low. Generally a measure must have a levelized cost of about 8 mills/KWh to be attractive to consumers. Only a few options, such as efficient lighting, meet this requirement.

The models have been run with the high discount rate to see how much conservation consumers would do on their own. That amount would have happened even without any conservation program. It can also be considered an estimate of the maximum potential of "free riders", persons who received a utility incentive for something they would have done anyway. Thus, an estimate of expected free ridership needs to be subtracted from the program outcome to give the net effect. In most cases, however, the free ridership is small. Consumers are not interested in programs unless the savings are extremely cheap.

Table 17 lists an estimate of the conservation that consumers would do on their own. Outside of solar access, there are no low-cost opportunities in new residential construction not incorporated in building codes. (The amount of solar access in existing practice was included in the basecase.) The largest amount of such conservation occurs in commercial sector. That is because there are many low-cost options. At least some of the customers should recognize those opportunities. Industrial sector is not included in this table because industrial "background" trends are already included in the econometric forecasting model.

The amount of background conservation, including MCS, is shown below. The amounts are compared for the four economic growth scenarios in Figure 25. Figure 26 shows the sector contributions for the medium high scenario. The amount of background in existing residential is almost too small to notice.

Table 18 Background Conservation Measures

	ECM's Included in Background Conservation	
	Existing	New Construction
Residential Lg SF	Tighten ACH	--
Commercial Office	Lights, incand>PL HVAC, tune & adjust	Lights, incand>PL HVAC, upgrade HP
Retail	Lights, 34W fluor. Lights, ballast>elect.	HVAC, storage rad. heater
Warehouse	HVAC, temp. setback HVAC, tune & adjust	Lights, incand>PL HVAC, storage rad. heater
Grocery	Envel., tighten ACH Lights, incand>PL HVAC, refer case timer HVAC, tune & adjust	Lights, Parab. reflector Lights, incand>PL
School	Envel., tighten ACH Lights, 2 level switch	--
Hospital	Lights, T8 fluor. Lights, incand>PL HVAC, temp. reset	Envel., insul. walls Lights, incand>PL
Restaurant	Envel., insul. roof	--
Lodging	Lights, effic. incand. Lights, incand>PL HVAC, temp. reset HVAC, low flow shower	HVAC, low flow shower

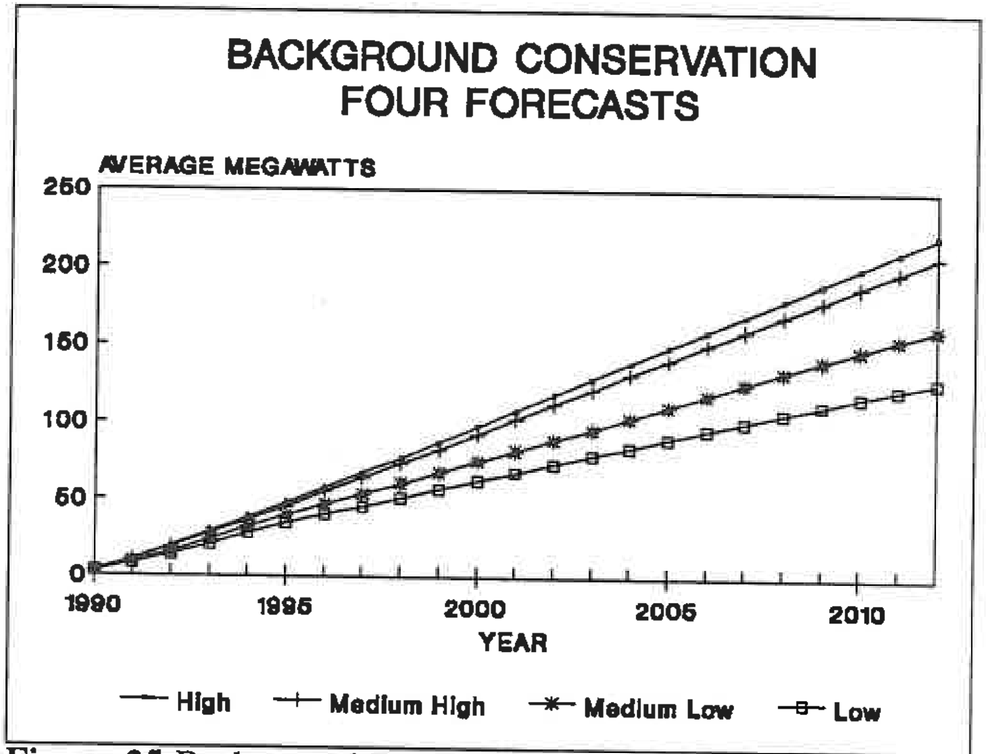


Figure 25 Background By Forecast

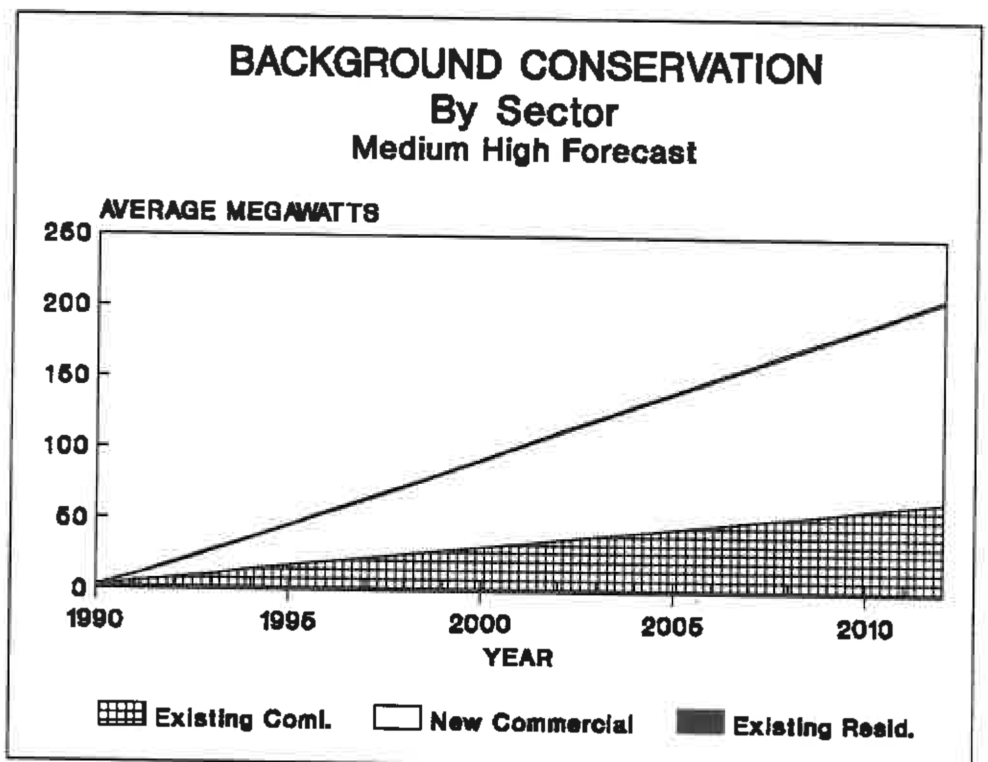


Figure 26 Background By Sector

9. LOST OPPORTUNITIES

9.1. Definition

Lost opportunities are those conservation resources which will be cost-effective during their lifetime if installed now, but not if installed later as part of a more expensive retrofit. Thus, lost opportunities are measures which should be installed even during a generation surplus.

Lost opportunities occur in several ways. First, the long-lived structural components of new buildings should be constructed to long-run cost-effectiveness standards. This is currently the rationale behind the Super Good Cents program for residential MCS. No similar program exists for new commercial construction, even though the potential for savings is much greater. the Company will participate to a limited extent in Bonneville's Energy Smart commercial program for new commercial. The program design of Energy Smart may be inadequate to capture lost opportunities without incentive payments.

Additional lost opportunities occur during remodel and replacement of the commercial building stock. There is a constant turn-over of commercial sales spaces through remodeling. Installation of some measures will be much cheaper if included during remodel.

In addition, there is an on-going repair and replacement of equipment in existing buildings due to component breakdown. It is often more cost-effective to replace with efficient equipment during the repair than to attempt upgrading retroactively. Both repair and remodel opportunities need to be evaluated against the likelihood of event windows. If there is a possibility of another window of opportunity occurring before the conservation is needed, the opportunity is not actually lost. Thus, if commercial sales spaces are remodeled every five years and conservation is not needed for five years, the measure can be postponed to the next window of opportunity.

For this analysis, we included lost opportunities based on the following criteria:

- o Current installation costs less than 55 mills/kWh.
- o Measure has a lifetime over 10 years.
- o Retrofit costs will exceed 55 mills/kWh or the levelized cost will increase be at least 50% as a retrofit.
- o The window of opportunity occurs on the average of 10 years or more.

The supply curve spreadsheets were used to calculate most of the sectors. An exception is commercial repair and remodel. For these estimates, spreadsheets developed for Bonneville by Gail Katz, SJO, were applied. These spreadsheets allowed updating for the square footage and fuel saturations appropriate for the Company territory. Only the small office and small retail sheets were utilized.

Table 19 Potential Lost Opportunity

Based on Medium High Forecast and 55 Mills/KWh Cost Ceiling
Technical Potential, MWa per Year

Sector	Technical Potential
New Residential Construction	1.3 MWa
New Mfg Homes	1.4
Solar Access	0.6
Appliances	
Refer/Freezer, Water Heater	5.0
New Commercial Construction	11.3
Commercial Remodel	3.0
Commercial Repair/ Replacement	0.8
Total Potential	23.4 MWa

9.2. Size of Potential Lost Opportunity

The bulk of the lost opportunities occur in commercial sector where programs are not in place. A significant amount appears during remodel and repair opportunities. Industrial sector opportunities are perhaps large but are not included in the above assessment. This is because industrial opportunities are quite site-specific and our level of knowledge is incomplete.

Some of the opportunity will occur even without utility programs as customers undertake conservation on their own. The amount of that background conservation is small since only the cheapest measures are attractive.

BALANCED PLANNING FOR GROWTH

Technical Appendix: Results

Resource and Market Planning Program
RAMPP - 2

May 14, 1992

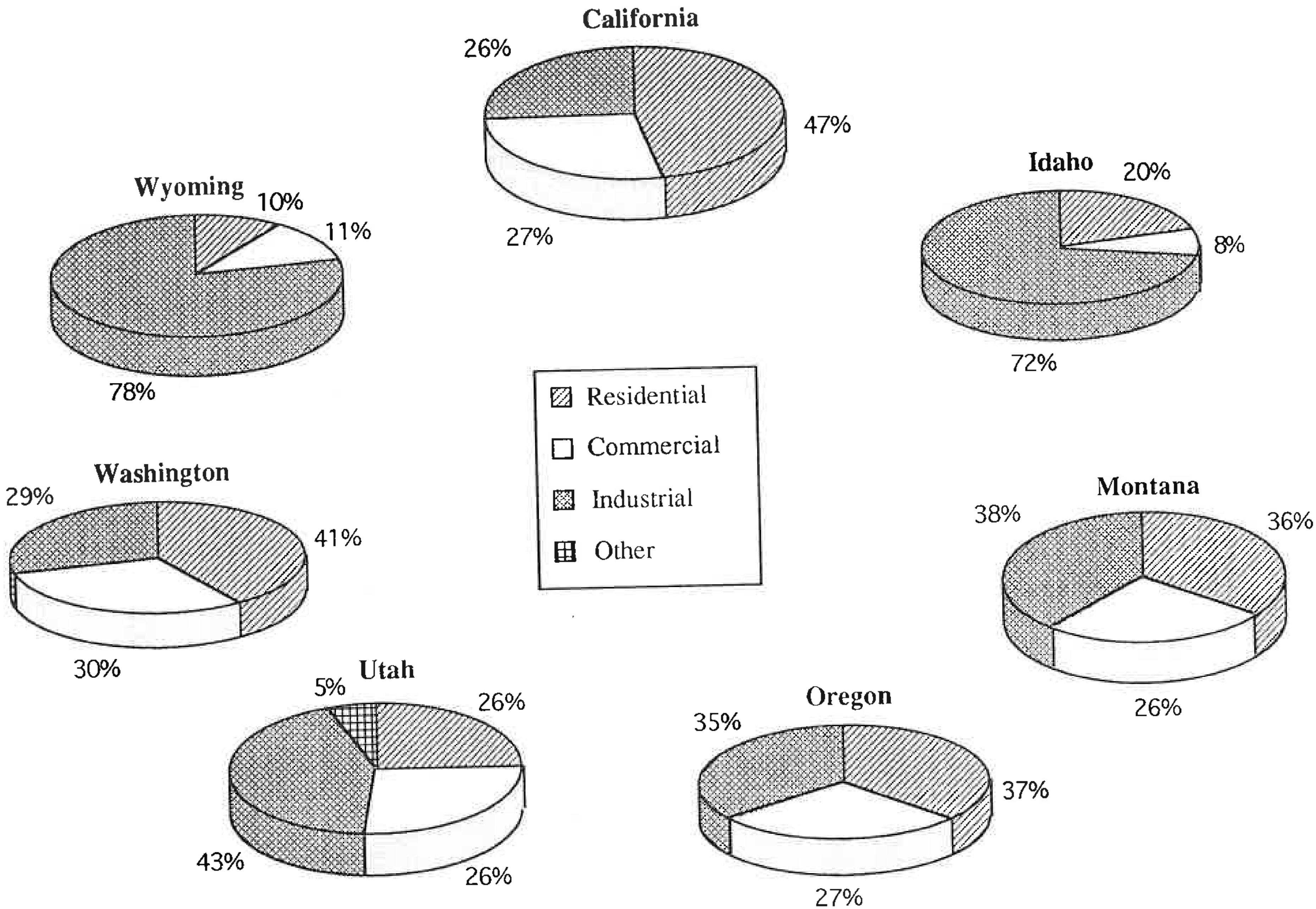
PACIFICORP

PacifiCorp RAMPP-2
Technical Appendix: Results

Table of Contents

ELECTRIC END USE BY STATE

PacifiCorp - RAMPP 2
Electrical End-Use by State



PUBLIC PROCESS

PacifiCorp RAMPP-2
Public Process

The RAMPP-2 Advisory Group (RAG) was an active participant in the development of this, the Company's second least cost plan. Representatives attended from the following agencies and groups:

Barakat & Chamberlain
Bonneville Power Administration
Drazen-Brubaker
Energy Strategies, Inc.
Industrial Customers of NW Utilitties
McKinsey & Co.
Montana Public Service Commission
National Resources Defense Council
Northwest Conservation Act Coalition
Northwest Power Planning Council
Oregon Department of Energy
Oregon Public Utilities Commission
Portland General Electric
Puget Power & Light
Ritts, Brickfield & Kaufman for Nucor Steel
Solar Energy Association of Oregon
Utah Committee of Consumer Services
Utah Division of Energy
Utah Division of Public Utilities
Utah Public Service Commission
Washington Office of the Attorney General
Washington State Energy Office
Washington Utilities and Transportation Commission
Wyoming Public Service Commission

Eleven all-day meetings were held with the RAG group. Before each meeting, a mailing was sent to all participants for them to review the materials that would be presented at the meetings. The meetings then were an opportunity for the participants to provide the Company with comments and concerns about the work in progress. Through this process, issues were raised and discussed throughout the progression of the plan, and the input of the group could be considered by the Company and incorporated into the plan.

In addition, subgroups met to more fully discuss specific topics. Those groups are identified below:

Demand Side Resources (3 meetings)
Forecasting (2 meetings)
Resource Cost Effectiveness (1 meeting)
External Costs (2 meetings)

PacifiCorp Electric Operations
Resource and Market Planning Program

RAMPP-2 Advisory Group Meeting

Thursday, October 11,1990
10:00 AM to 3:00 PM
Room 280 PFFC
Pacific First Federal Center

Agenda

10:00 Opening and Introductions - David Engberg & John Shue

10:15: Proposed Schedule for the RAMPP-2 Process - Jim Abrahamson

10:30 Discussion Concerning the Role of the Advisory Group - David Engberg

11:30 General Discussion of Analytical Methods:

Load Forecasting - Paul Wrigley
Demand-Side Resources - Dave Robison

12:30 Lunch

1:00 General Discussion of Analytical Methods (Continued)

Supply-Side Resources - David Engberg

1:30 Near-Term Action Plan Implementation Update:

Customer Energy Efficiency Programs - John Shue
System Efficiency Programs - David Engberg
Marketplace and Cost-Effective Opportunities - David Engberg
Implementation of Firming Strategy - David Engberg
Address Future Planning Issues - Dave Robison & Jim Abrahamson

2:40 General Discussion

3:00 Adjourn

PRELIMINARY AGENDA

RAG 2 MEETING
FEBRUARY 1, 1991

10:00 - 10:15
Opening Remarks

10:15 - 11:00
Pacificorp Electric Operations Corporate Goals
Paul Lorenzini, Executive Vice President

11:00 - 11:30
RAMPP-2 Issues Follow-up
David Engberg

11:30 - 12:00
OPUC's LC-1 Order to Pacific
Lee Sparling: Staff's interpretation of the Order
Staff's definition of cost effectiveness
David Engberg: Pacific's interpretation of the Order

12:00 - 12:15
Lunch served (to be eaten during following presentation)

12:15 - 12:45
Discount Rates
Bernard Versari
Pacific's position on the appropriate rate
Calculation of current rate

12:45 - 1:30 Economic Forecast
Paul Wrigley

1:30 - 2:15 Externalities
Nancy Esteb
Methodology

2:15 - 3:00
Demand Side Resource Report
Dave Robison
Methodology
Conservation Cost Effectiveness

PacifiCorp Electric Operations
RAMPP-2 Advisory Group
Meeting March 22, 1991
Preliminary Agenda

Corrections to the minutes

Process check and work groups

Environmental issues: continuation of discussion

Sales forecasts

Conservation cost effectiveness
- Issues
- Report of task group

DSR program implementation

Existing resource system

New strategic plan: wrap-up

Scenario development

Concluding remarks and suggestions for next agenda

PacifiCorp Electric Operations
RAMPP-2 Advisory Group
Meeting May 3, 1991

Agenda

10:00 - 10:30
Report on Utah meetings
Organization chart of Company departments in RAMPP
Review of minutes
Review of today's agenda
Schedule next meeting

10:30 - 11:00
Environmental cost ranges to be used in resource planning

11:00 - 11:15
Resource cost effectiveness

11:15 - 12:00
Report on DSR task group
DSR draft programs

12:00 - 12:15
Participants select lunches

12:15 - 1:15
Report on forecast task group
Forecast results for four forecasts

1:15 - 1:45
Scenario descriptions

1:45 - 2:45
Uncertainty
Resource selection assumptions and decision rules
Capacity benefits
Discount rate sensitivity
Environmental cost sensitivities

2:45 - 3:00
Closing

PACIFICORP ELECTRIC OPERATIONS
RAMPP ADVISORY GROUP
MEETING JUNE 14, 1991
AGENDA

10:00 - 10:15
Welcome
Minutes corrections
Agenda revisions
Scheduling next meetings

10:15 - 10:45
Discount rate

10:45 - 12:00
Commercial, Industrial, and Total Forecasts

12:00 - 12:15
Participants select lunches

12:15 - 12:45
Bruce Folsom of WUTC: LCP and Business Planning

12:45 - 1:00
Scenarios: revisions from participant input

1:00 - 1:30
Environmental Costs: report from task group

1:30 - 2:15
Supply Resource Costs

2:15 - 2:45
Picker Model

2:45 - 3:00
Closing

PACIFICORP ELECTRIC OPERATIONS
RAMPP ADVISORY GROUP
MEETING AUGUST 9, 1991

AGENDA

10:00 - 10:15
Welcome
Minutes corrections
Agenda revisions
Scheduling next meetings

10:15 - 10:45
Final Forecasts

10:45 - 11:45
Existing System versus Forecasts
Supply Portfolio

11:45 - 12:00
Participants select lunches

12:00 - 12:45
DSR Technical Potential
DSR Program Development

12:45 - 1:30
Marketplace Assessment
Cogeneration Assessment

1:30 - 2:15
Environmental Costs: report from task group

2:15 - 2:45
Report Outline and Timeline

2:45 - 3:00
Closing

PACIFICORP ELECTRIC OPERATIONS
RAMPP ADVISORY GROUP
MEETING OCTOBER 4, 1991

10:00 - 10:15
Welcome
Minutes corrections
Agenda revisions
Schedule next meetings

10:15 - 11:00
Report of DSR task group
DSR Programmatic Supply Curves

11:00 - 11:30
Report of Externalities Subgroup

11:30 - 12:00
RIM Model Logic

12:00 - 12:15
Participants select lunches

12:15 - 1:00
RIM Model Logic, continued

1:00 - 2:15
RIM Demonstration

2:15 - 2:45
RIM Key Outputs Q&A

2:45 - 3:00
Closing

PACIFICORP ELECTRIC OPERATIONS
RAMPP ADVISORY GROUP
MEETING NOVEMBER 15, 1991

10:00 - 10:15
Welcome
Minutes corrections
Agenda revisions

10:15 - 10:45
Revised Schedule for Draft Report
Schedule next meetings

10:45 - 11:15
Report of DSR task group

11:15 - 12:00
Portfolio/Existing Plants Sensitivities for External Costs

12:00 - 12:15
Participants select lunches

12:15 - 12:45
Illustrative trial plans for medium-high forecast
Explanation of model assumptions

12:45 - 1:30
Illustrative trial plans for medium-high forecast
DSR Discussion

1:30 - 2:45
Illustrative trial plans for medium-high forecast
Non-DSR Discussion

2:45 - 3:00
Closing

PACIFICORP ELECTRIC OPERATIONS
RAMPP ADVISORY GROUP
MEETING DECEMBER 20, 1991
Agenda

10:00 - 10:15
Welcome
Minutes corrections
Agenda revisions
Scheduling next meetings, time
Corporate organizational changes

10:15 - 10:30
RIM model: letters Company received, Company response

10:30 - 11:00
Discount rate sensitivity

11:00 - 11:15
Gas price change to lower forecast

11:15 - 12:00
Illustrative plan sensitivities for medium-high forecast

12:00 - 12:15
Participants select lunches

12:15 - 1:30
Proposed illustrative plans for four forecasts

1:30 - 2:00
Proposed illustrative plans for scenarios

2:00 - 2:15
DSR cost effectiveness

2:15 - 2:45
Uncertainty analysis: suggestions for model runs

2:45 - 3:00
Process check
Closing

PACIFICORP ELECTRIC OPERATIONS
RAMPP ADVISORY GROUP
January 24, 1992
Agenda

9:00 - 9:15
Welcome
Minutes corrections
Agenda revisions
Scheduling next meeting

9:15 - 9:45
Follow-up from last meeting

9:45 - 10:30
Summary table of RIM runs

10:30 - 10:45
Break

10:45 - 11:30
Four forecast illustrative plans

11:30 - 12:00
Four scenarios illustrative plans

12:00 - 12:30
Lunch

12:30 - 1:00
Four environmental cost levels sensitivity runs

1:00 - 1:30
Emissions data

1:30 - 2:15
Demand-Side Action Plan

2:15 - 2:45
Supply-Side Action Plan

2:45 - 3:00
Process check

PACIFICORP ELECTRIC OPERATIONS
RAMPP ADVISORY GROUP
MEETING MARCH 20, 1992
Agenda

10:00 - 10:15
Welcome
Minutes corrections
Agenda revisions
Corporate organizational changes

10:15 - 10:30
Planned Revisions to the Final Report

10:30 - 11:00
General Comments

11:00 - 11:30
Avoided Cost Q&A with Greg Duvall

11:30 - 12:00
Conservation Cost Effectiveness with Carole Rockney

12:00 - 12:30
Lunch

12:30 - 2:45
Comments on Chapters

2:45 - 3:00
Process check
Closing

RESOURCE INTEGRATION MODEL

PACIFICORP ELECTRIC OPERATIONS
RAMPP-2

RESOURCE INTEGRATION MODEL (RIM)

Purpose

RIM develops a multi-year resource plan which integrates the use of new demand and supply resources to meet system needs. System needs arise as existing resources are insufficient to meet the load level specified by a load forecast.

The primary purpose of the model is to test different resource strategies in the face of uncertainty. The analyst specifies a particular load forecast at the beginning of the study period. The model makes resource decisions for the first year, and then moves on to the next year. At this point, the analyst can let the model continue using the original load forecast, or the analyst can specify a new, unexpected forecast. The model may then change some of the prior year's decisions to adjust its resource choices.

It is the model's ability to change the forecast mid-stream that allows for uncertainty to be included in the development of resource plans. Unexpected changes in load growth can be introduced to test the flexibility of different resource strategies.

Overview

For each new study period, the analyst specifies the inputs. Based on these inputs, the model creates a resource plan for a varying number of years in length.

At the beginning of each year of the study period, RIM compares the system resources to the load forecast to determine the system needs for that year. RIM develops scores for all the available resources based on their energy and capacity costs. It then selects and adds the resource with the highest score. At this point, although a resource has been added, the new total of resources is probably not at a level that meets the forecast, but the system energy and capacity needs have changed because of the added resource. So the model again scores all the remaining resources, then selects and adds the next resource. This process of scoring, selecting, and adding is repeated until the model has added enough resources for that year to bring the total resources to the forecast level.

After the model has filled the need for one year, it will examine all the resources it added, to see if any could be delayed and still remain within the energy and capacity balances. For example, if a smaller resource is added before a larger one, and the larger one brings the system into the target balance range, perhaps the smaller one could then be delayed.

After the selections for a year are made, the new level of resources becomes the set of system resources for the next year. RIM then compares the new level of system resources to the load forecast for the new year. It selects resources to fill the gap between the level of system resources and the load forecast, and then moves on to the next year. This continues until it has created a resource plan for the entire study period.

Price Score

The model uses both the energy and capacity costs of each resource to determine which resources to select, and in what order to select them. A combined energy and capacity price is calculated per kWh based on the relative mix of energy and capacity needed by the system at that point. Each resource file includes information on its rated capacity and the maximum and minimum capacity factors. The amount of energy over which the model spreads the capacity cost is, at a minimum, the energy calculated using the resource's minimum capacity factor. However, if the system needs more energy than that, the amount of energy over which the model spreads the capacity cost will be the amount of energy the system needs, up to the amount of energy which would be produced at the resource's maximum capacity factor.

Horizon Years

The model needs to mimic the long range decisions that are made in normal utility planning. To do this, it accommodates the lead time requirement of resources. The term horizon years is used in the model to signify the number of years out the model tries to bring into the load/resource balance target range. It needs to be at least as long as the longest lead time of the resource alternatives, or that long lead time resource will never be selected.

In the attached example, ten years was used. When the model reaches the year 2001, it has planned resource additions for the years through 2011, and has done its work.

In decision year 1991, the the model will add sufficient resources in each of the next ten horizon years to bring each of those years into the target range. For horizon year 1992, it calculates scores for those resources which have a short enough lead time that they could be available (on line) in 1992, and of these commits those which are needed to bring the system into the target range. It then looks at horizon year 1993, again calculates scores for those resources with appropriate lead times, and adds resource(s). The model follows the same procedure for each of the ten horizon years, calculating scores, selecting resources, and flagging them as planned or committed, depending on their lead times.

The model then moves on to decision year 1992. Its task is to examine the situation for each of the next 10 years (the horizon years for decision year 1992). At this point a new reality can be introduced. The new reality includes the deficit for each of the horizon years, and any resources that were committed for any of those horizon years during decision year 1991. The model has the flexibility to delay any committed resources one year at a time. For each horizon year, it calculates scores, evaluates each committed resource to determine if it should be delayed or not, selects new resources as needed, and flags them as planned or committed. The model requires that delay and cancel decisions do not allow the balance to go below the target range.

Uncertainty

In the real world, planners look into the future and make decisions based on their best guesses. Commitments are made to meet immediate requirements, tentative plans are made for the future, and ground work is laid for long term projects. The next year the process is repeated beginning with a new view of the future which incorporates the knowledge of the previous year. Commitments to previous decisions are reexamined, timetables for ongoing projects are adjusted and a new tentative plan is established.

The RIM process mimics this real world process. The user may specify a "new reality" each time the study moves on to the next decision year. The model follows a sequence of incorporating any new information, making a plan for the horizon years, moving to the next decision year, incorporating any new information, making a plan, etc. Every time it moves to the next decision year, it has an opportunity to incorporate new information and make changes to the prior decision year's resource decisions for the horizon years.

Study Parameter Input File

A study input file contains the user specified parameters and model instructions. The analyst may specify the time dimensions, and list the available resources for the particular study.

The following definitions follow the sequence of parameters as seen on the sample Parameter File that is attached.

Decision Year: the year in which resource planning and commitment decisions are made. The start year tells the model when to begin evaluating loads and resources to make decisions about adding resources. The end year tells the model when to stop making decisions.

Report Year: identifies the year for which the model will display a resource plan.

Horizon Years: The number of years beyond each decision year that the model tries to bring into the load/resource balance target range.

Combine Price: Instructs the model to calculate one price score based on the load factor for each resource.

Energy Derate Multiplier: The number the model uses to multiply times the unitized energy price if the energy derate trigger applies.

Energy Derate Trigger: The load factor below which the energy derate multiplier will be used. The load factor is calculated when the balance is outside the target range.

Target Low: Establishes the lower bound for the desired load/resource balance target range.

Target High: Establishes the upper bound for the desired load/resource balance target range.

Resource Input Files

For each of the available resources listed in the study parameter file there is a resource file which contains the information needed by the model to select resources. This is primarily cost and availability information.

Resource Type: Identifies each resource as owned or non-owned. If owned, the model adds to the system's reserve requirements. Owned resources increase the lower and upper bound for the capacity range to allow for an increased reserve margin.

Dollar Year: Is used to transfer information from the RIM to the summary financial model.

Must Use: Means that the model must add this resource by the last available date.

Lead Years: The number of years from committing to when the resource is fully available.

Cancel Years: The number of years remaining in the lead time to be able to cancel the resource.

Delay Years: The number of years remaining in the lead time to be able to delay the resource.

Delay Times: The number of times that a resource can be delayed one year.

Term: The number of years that the resource is fully available.

Number Use: The number of times that that resource can be used in the plan. It is the number of units that are available.

First Available: The first calendar year that the resource is fully available.

Last Available: The last calendar year that the resource is fully available.

Min Load Factor: Used to calculate the minimum and maximum energy values available from the unit. It is used in the price calculation.

Max Load Factor: Used to calculate the minimum and maximum energy values available from the unit. It is used in the price calculation.

Results

The output is load/resource tables for energy, winter peak, and summer peak. Each one shows, for each of the 20 years, the load requirements, resources, and balance. The system requirements include both system loads and firm sales. The resources include native generation (existing system), firm purchases, and the new resources that are added to meet the growing system requirements. The balance is derived by subtracting load requirements from the total resources.

ASSUMPTIONS OF RIM RUNS

PacifiCorp - RAMPP 2
Assumptions used in RIM Runs

	2010 System Retail Load In Ave.MW's	1991 - 2010 Retail Load Growth Ave.%	Energy Added by 2010 Ave.MW's	Capacity Added by 2010 MW's	1991 Gas Price ($/mmbtu)	1991-2010 Real Gas Esc. % Growth/Yr	2011-2045 Real Gas Esc. % Growth/Yr	Forced in Green Ave.MW's	Loss of Resources from Base: Capacity Lost by 2010 in MW's	Energy Lost by 2010 in aMW's	Forced SCCT's	Additional Resources in Portfolio: Wind	Geothermal	Pumped Storage
Low (L) Forecast	5,573	0.4%	524	904	$1.650	4.61%	0.00%	0	0	0	No	No	No	No
Medium low (ML) forecast	6,952	1.5%	1,084	2,057	$1.650	4.61%	0.00%	60	0	0	No	No	No	No
Med. High - Step 1	9,233	3.1%	3,393	5,469	$1.650	4.61%	0.00%	0	0	0	No	No	No	No
Med High - Step 2	9,233	3.1%	3,424	5,495	$1.650	4.61%	0.00%	218	0	0	No	No	No	No
Med High - Step 3	9,233	3.1%	3,399	5,333	$1.650	4.61%	0.00%	218	0	0	No	No	No	No
Med. High Preferred - Step 4	9,233	3.1%	3,362	5,341	$1.650	4.61%	0.00%	218	0	0	Yes	No	No	No
High (H) forecast base	11,129	4.1%	5,639	8,665	$1.948	4.61%	0.00%	231	0	0	Yes	No	No	No
High Preferred	11,129	4.1%	5,587	8,553	$1.948	4.61%	0.00%	231	0	0	Yes	Yes	Yes	No
Electrification scenario	13,370	5.1%	8,200	12,141	$1.948	4.61%	0.00%	218	0	0	Yes	No	No	No
High gas scenario (MH)	9,233	3.1%	3,393	6,303	$1.948	4.61%	3.36%	218	0	0	No	No	No	No
Loss of resources scenario (MH)	9,233	3.1%	3,901	5,996	$1.650	4.61%	0.00%	218	400	80+	Yes	No	No	No
CO2 tax scenario (MH)	9,233	3.1%	3,452	5,179	$1.650	4.61%	0.00%	218	0	0	No	Yes	Yes	No
ML forecast, L actual	5,551	0.3%	658	1,293	$1.650	4.61%	0.00%	60	0	0	No	No	No	No
ML forecast, MH actual	9,177	3.0%	3,575	5,616	$1.650	4.61%	0.00%	60	0	0	No	No	No	No
MH forecast, ML actual	6,935	1.5%	1,274	2,561	$1.650	4.61%	0.00%	218	0	0	Yes	No	No	No
MH forecast, H actual	11,151	4.1%	5,835	8,831	$1.650	4.61%	0.00%	218	0	0	Yes	No	No	No
MH forecast, H excursion	11,006	4.0%	5,705	8,704	$1.650	4.61%	0.00%	218	0	0	Yes	No	No	No
MH forecast, H short excursion	9,448	3.2%	3,809	6,158	$1.650	4.61%	0.00%	218	0	0	Yes	No	No	No
DSR 30% less (MH)	9,233	3.1%	3,584	5,536	$1.650	4.61%	0.00%	218	0	0	Yes	No	No	No
DSR 30% more (MH)	9,233	3.1%	3,689	6,357	$1.650	4.61%	0.00%	218	0	0	Yes	No	No	No
Environmental Level 1 (MH)	9,233	3.1%	3,399	5,333	$1.650	4.61%	0.00%	218	0	0	No	No	No	No
Environmental Level 2 (MH)	9,233	3.1%	3,376	5,327	$1.650	4.61%	0.00%	218	0	0	No	No	No	No
Environmental Level 3 (MH)	9,233	3.1%	3,366	5,258	$1.650	4.61%	0.00%	218	0	0	No	No	No	No
Environ. Level 3 High Gas (MH)	9,233	3.1%	3,448	5,337	$1.948	4.61%	3.36%	218	0	0	No	Yes	Yes	No
Environmental Level 4 (MH)	9,233	3.1%	3,406	5,372	$1.650	4.61%	0.00%	218	0	0	No	Yes	Yes	No
Average Water (MH)	9,233	3.1%	3,308	5,445	$1.650	4.61%	0.00%	218	0	0	No	No	No	No
Less thermal by 10% (MH)	9,233	3.1%	3,381	5,983	$1.650	4.61%	0.00%	218	0	580	No	No	No	No
All Renewables (MH)	9,233	3.1%	3,393	5,173	$1.650	4.61%	0.00%	218	0	0	No	Yes	Yes	Yes
Renewables 20% less cost (MH)	9,233	3.1%	3,398	5,391	$1.650	4.61%	0.00%	218	0	0	Yes	Yes	Yes	No

Supply Side Resources
Estimating Assumptions

Capital Assumptions

- All estimates include AFUDC at 11%.
- All estimates include Owners G&A.
- All estimates include initial spare parts, chemical & start up costs.
- Switchyard & Transmission costs are excluded (except Hunter 4).
- Costs associated with licensing a facility are indicated separately.
- All costs are in 1991 dollars.
- Income from sale of start-up power excluded.
- A nominal cost for land is included in all estimates.
- A three month fuel inventory is included for coal plants.

Operation & Maintenance

- Plant capacity factor is expressed in terms of "net" plant capacity.
- Operating costs are estimated for a year of normal operation.
- Company G&A allocations to the operation of these facilities are not included in the O&M figures provided.
- Replacement Capital is not included in O&M.

Fuel

- Cost of rolling stock included in capital cost of facilities.
- A 14 day inventory of distillate oil is included as backup for the natural gas fired plants to accommodate gas supply interruptions.

Plant Licensing Cost

Licensing Cost as a Percent of Capital Cost

Size	Low	Expected	High
>50 MW	1%	1.5%	2%
<50 MW	2%	2.5%^	3%

Assumption: 1. No strident opposition.

<u>MEDIUM HIGH 4 STEPS</u>

<u>HIGH 2 STEPS</u>

RAMPP 2 - Resources Added (MWa)

	Medium-High Forecast Steps				High Forecast Steps	
	Medium-High Step 1	Medium-High Step 2	Medium High Step 3	Medium-High Step 4	High Forecast Step 1	High Forecast Step 2
D.S. Lost Ops	1992 - 3	1992 - 3	1992 - 3	1992 - 3	1992 - 4	1992 - 4
D.S. Lost Ops	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 4	1993 - 4
D.S. Lost Ops	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 6	1994 - 6
D.S. Lost Ops	1995 - 9	1995 - 9	1995 - 9	1995 - 9	1995 - 10	1995 - 10
D.S. Lost Ops	1996 - 11	1996 - 11	1996 - 11	1996 - 11	1996 - 13	1996 - 13
D.S. Lost Ops	1997 - 11	1997 - 11	1997 - 11	1997 - 11	1997 - 13	1997 - 13
D.S. Lost Ops	1998 - 11	1998 - 11	1998 - 11	1998 - 11	1998 - 13	1998 - 13
D.S. Lost Ops	1999 - 12	1999 - 12	1999 - 12	1999 - 12	1999 - 14	1999 - 14
D.S. Lost Ops	2000 - 12	2000 - 12	2000 - 12	2000 - 12	2000 - 14	2000 - 14
D.S. Lost Ops	2001 - 12	2001 - 12	2001 - 12	2001 - 12	2001 - 13	2001 - 13
D.S. Lost Ops	2002 - 11	2002 - 11	2002 - 11	2002 - 11	2002 - 13	2002 - 13
D.S. Lost Ops	2003 - 11	2003 - 11	2003 - 11	2003 - 11	2003 - 13	2003 - 13
D.S. Lost Ops	2004 - 11	2004 - 11	2004 - 11	2004 - 11	2004 - 13	2004 - 13
D.S. Lost Ops	2005 -10	2005 - 10	2005 - 10	2005 - 10	2005 - 12	2005 - 12
D.S. Lost Ops	2006 - 10	2006 - 10	2006 - 10	2006 - 10	2006 - 12	2006 - 12
D.S. Lost Ops	2007 - 10	2007 - 10	2007 - 10	2007 - 10	2007 - 12	2007 - 12
D.S. Lost Ops	2008 - 10	2008 - 10	2008 - 10	2008 - 10	2008 - 12	2008 - 12
D.S. Lost Ops	2009 - 10	2009 - 10	2009 - 10	2009 - 10	2009 - 12	2009 - 12
D.S. Lost Ops	2010 - 10	2010 - 10	2010 - 10	2010 - 10	2010 - 12	2010 - 12
D.S. Lost Ops	2011 - 10	2011 - 10	2011 - 10	2011 - 10	2011 - 12	2011 - 12
D.S. Options	1992 - 10	1992 - 10	1992 - 10	1992 - 10	1992 - 12	1992 - 12
D.S. Options	1993 - 10	1993 - 10	1993 - 10	1993 - 10	1993 - 11	1993 - 11
D.S. Options	1994 - 14	1994 - 14	1994 - 14	1994 - 14	1994 - 17	1994 - 17
D.S. Options	1995 - 20	1995 - 20	1995 - 20	1995 - 20	1995 - 24	1995 - 24
D.S. Options	1996 - 33	1996 - 33	1996 - 33	1996 - 33	1996 - 39	1996 - 39
D.S. Options	1997 - 43	1997 - 43	1997 - 43	1997 - 43	1997 - 51	1997 - 51
D.S. Options	1998 - 52	1998 - 52	1998 - 52	1998 - 52	1998 - 60	1998 - 60
D.S. Options	1999 - 51	1999 - 51	1999 - 51	1999 - 51	1999 - 59	1999 - 59
D.S. Options	2000 - 49	2000 - 49	2000 - 49	2000 - 49	2000 - 57	2000 - 57
D.S. Options	2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 53	2001 - 53
D.S. Options	2002 - 43	2002 - 43	2002 - 43	2002 - 43	2002 - 50	2002 - 50
D.S. Options	2003 - 41	2003 - 41	2003 - 41	2003 - 41	2003 - 48	2003 - 48
D.S. Options	2004 - 40	2004 - 40	2004 - 40	2004 - 40	2004 - 48	2004 - 48
D.S. Options	2005 - 37	2005 - 37	2005 - 37	2005 - 37	2005 - 40	2005 - 40
D.S. Options	2006 - 27	2006 - 27	2006 - 27	2006 - 27	2006 - 32	2006 - 32
D.S. Options	2007 - 16	2007 - 16	2007 - 16	2007 - 16	2007 - 19	2007 - 19
D.S. Options	2008 - 16	2008 - 16	2008 - 16	2008 - 16	2008 - 18	2008 - 18
D.S. Options	2009 - 14	2009 - 14	2009 - 14	2009 - 14	2009 - 16	2009 - 16
D.S. Options	2010 - 14	2010 - 14	2010 - 14	2010 - 14	2010 - 16	2010 - 16
D.S. Options	2011 - 13	2011 - 13	2011 - 13	2011 - 13	2011 - 16	2011 - 16
BPA Exchange	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26	1997 - 26
BPA Exchange	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38	1998 - 38
Cogen	1995 0 85	1995 - 80	1995 - 80	1995 - 80	1994 - 80	1994 - 85
Cogen	1996 - 80	1995 - 80	1995 - 80	1995 - 80	1994 - 80	1994 - 85
Cogen	1996 - 85	1996 - 85	1996 - 85	1996 - 85	1994 - 85	1994 - 80
Cogen	1996 - 85	1996 - 85	1996 - 85	1996 - 85	1994 - 85	1994 - 80
Cogen					1994 - 85	1994 - 85
Cogen					1995 - 85	1995 - 85
Cogen						2003 - 85
Cogen						2003 - 85
Cogen						2003 - 85
Cogen						2004 - 85
Cogen						
Cogen						

RAMPP 2 - Resources Added (MWa)

	Medium-High Forecast Steps				High Forecast Steps	
	Medium-High Step 1	**Medium-High Step 2**	**Medium High Step 3**	**Medium-High Step 4**	**High Forecast Step 1**	**High Forecast Step 2**
Cogen						
Geothermal		1999 - 45	1999 - 45	1999 - 45	1999 - 45	1999 - 45
Geothermal		2000 - 45	2000 - 45	2000 - 45	2000 - 45	2000 - 45
Geothermal		2001 - 45	2001 - 45	2001 - 45	2001 - 45	2001 - 45
Geothermal					2010 - 175	2005 - 45
Geothermal						2006 - 45
Geothermal						2007 - 45
Geothermal						2008 - 45
Geothermal						
Geothermal						
Geothermal						
Geothermal						
Geothermal						
Geothermal						
Geothermal						
Geothermal						
Wind	1995 - 30	1996 - 5	1996 - 5	1996 - 5	1996 - 5	1996 - 5
Wind	1998 - 30	1997 - 17	1997 - 17	1997 - 17	1997 - 17	1997 - 17
Wind		1998 - 16	1998 - 16	1998 - 16	1998 - 16	1998 - 16
Wind		1999 - 5	1999 - 5	1999 - 5	1999 - 5	1999 - 5
Wind		2000 - 15	2000 - 15	2000 - 15	2000 - 15	2000 - 15
Wind		2001 - 15	2001 - 15	2001 - 15	2001 - 15	2001 - 15
Wind		2002 - 10	2002 - 10	2002 - 10	2002 - 10	2002 - 10
Wind						2004 - 5
Wind						2005 - 17
Wind						2006 - 16
Wind						2007 - 5
Wind						2008 - 15
Wind						2009 - 15
Wind						2010 - 10
Wind						
Wind						
Wind						
Wind						
Wind						
Wind						
Wind						
Wind						
Wind						
Wind						
Wind						
Wind						
Wind						
Small SC CT	2003 - 8	1996 - 4	1996 - 4		1997 - 4	1997 - 4
Small SC CT	2003 - 8	1996 - 4	1996 - 4		1997 - 4	1997 - 4
Small SC CT	2003 - 4	1996 - 4	1996 - 4		1998 - 4	1998 - 4
Small SC CT	2003 - 4	1997 - 4	1997 - 4		1998 - 4	1998 - 4
Small SC CT	2003 - 4	1997 - 4	1997 - 4		2003 - 4	2005 - 4
Small SC CT	2003 - 4	1997 - 4	1997 - 4		2003 - 4	2006 - 4
Small SC CT	2004 - 4	1999 - 8	1999 - 8		2004 - 4	2008 - 8
Small SC CT	2004 - 4	1999 - 4	1999 - 8		2004 - 4	
Small SC CT	2004 - 4	2000 - 4	1999 - 8			
Small SC CT	2004 - 4	2006 - 8	2007 - 8			
Small SC CT	2004 - 8	2006 - 8				

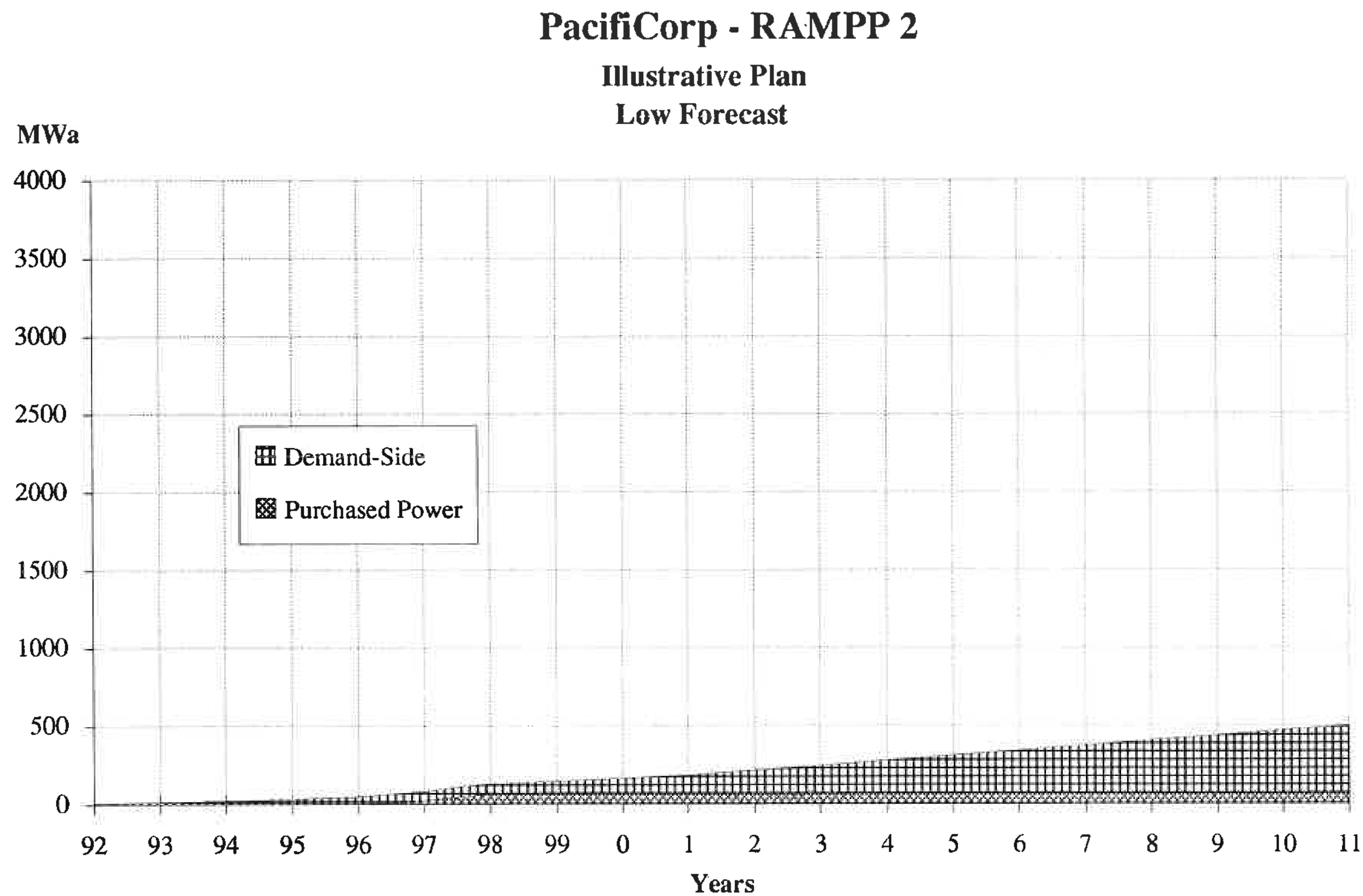
RAMPP 2 - Resources Added (MWa)

	Medium-High Forecast Steps				High Forecast Steps	
	Medium-High Step 1	Medium-High Step 2	Medium High Step 3	Medium-High Step 4	High Forecast Step 1	High Forecast Step 2
Small SC CT						
Medium SC CT	2000 - 20	2003 - 20	1999 - 20	1996 - 10		2000 - 20
Medium SC CT		2004 - 20	2000 - 20	1997 - 10		
Medium SC CT			2011 - 10	1999 - 20		
Medium SC CT				1999 - 20		
Medium SC CT				2000 - 20		
Medium SC CT						
Medium SC CT						
Medium SC CT						
Medium SC CT						
Large SC CT	1996 - 31	1998 - 31	1998 - 31	1998 - 31	1996 - 31	1996 - 31
Large SC CT	1998 - 31	1998 - 31	1998 - 31	1998 - 31	1998 - 31	1998 - 31
Large SC CT	1999 - 31	1999 - 31			2000 - 16	2000 - 31
Large SC CT	2000 - 31	2000 - 31			2000 - 31	2003 - 31
Large SC CT	2000 - 16	2003 - 31			2001 - 16	2006 - 31
Large SC CT	2000 - 16	2003 - 31				
Large SC CT	2001 - 16	2003 - 31				
Large SC CT	2001 - 16					
Large SC CT						
Large SC CT						
Large SC CT						
Large SC CT						
Medium CC CT	1999 - 64				2003 - 32	
Medium CC CT	2011 - 64				2004 - 32	
Medium CC CT					2008 - 32	
Medium CC CT					2009 - 32	
Medium CC CT						
Medium CC CT						
Medium CC CT						
Medium CC CT						
Large CC CT	1997 - 175	1997 - 175	1997 - 175	1997 - 175	1996 - 175	1996 - 175
Large CC CT	2005 - 175	2002 - 88	2001 - 175	2001 - 175	1996 - 175	1996 - 175
Large CC CT	2006 - 175	2003 - 87	2002 - 175	2002 - 175	1997 - 175	1997 - 175
Large CC CT	2007 - 175	2007 - 175	2003 - 175	2003 - 175	1998 - 175	1998 - 175
Large CC CT	2008 - 88	2008 - 175	2005 - 175	2005 - 175	1999 - 175	1999 - 175
Large CC CT	2009 - 87	2009 - 175	2006 - 175	2006 - 175	2003 - 175	2002 - 175
Large CC CT	2009 - 175	2010 - 175	2007 - 88	2009 - 175	2004 - 88	2005 - 175
Large CC CT	2010 - 175	2011 - 175	2008 - 87	2010 - 175	2005 - 87	2006 - 175
Large CC CT	2011 - 175	2011 - 88	2008 - 88	2011 - 175	2005 - 175	2007 - 175
Large CC CT			2009 - 87	2011 - 88	2006 - 175	2008 - 175
Large CC CT			2009 - 88		2006 - 88	2009 - 175
Large CC CT			2010 - 87		2007 - 87	2009 - 175
Large CC CT			2010 - 175		2007 - 175	2010 - 175
Large CC CT					2008 - 175	2010 - 88
Large CC CT					2009 - 175	2011 - 87
Large CC CT					2010 - 175	2011 - 175
Large CC CT					2010 - 175	2011 - 88
Large CC CT					2011 - 175	
Large CC CT					2011 - 175	
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						

RAMPP 2 - Resources Added (MWa)

	Medium-High Forecast Steps				High Forecast Steps	
	Medium-High Step 1	Medium-High Step 2	Medium High Step 3	Medium-High Step 4	High Forecast Step 1	High Forecast Step 2
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Large CC CT						
Wyodak 2	2003 - 192	2001 - 192	2011 - 192		2002 - 192	
Hunter 4	2001 - 300	2005 - 300	2007 - 300	2007 - 300	2001 - 300	2001 - 300
AFB Coal						
AFB Coal						
AFB Coal						
AFB Coal						
IGCC Coal						
IGCC Coal						
IGCC Coal						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						
Pumped Storage						

ILLUSTRATIVE PLAN RESULTS


PacifiCorp - RAMPP 2
Illustrative Plan
Low Forecast
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

Low Forecast

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5075.0	5169.0	5225.0	5227.0	5229.0	5240.0	5257.0	5278.0	5294.0	5313.0	5333.0	5347.0	5369.0	5403.0	5441.0	5481.0	5515.0	5547.0	5573.0
Total Conservation	4.5	9.3	16.5	25.7	35.7	46.8	58.5	70.6	83.6	100.1	122.4	151.5	182.1	213.9	246.2	277.9	309.9	341.8	373.7	405.2
System Load net of Conservation	5195.5	5065.7	5152.5	5199.3	5191.3	5182.2	5181.6	5186.4	5194.4	5194.0	5190.6	5181.5	5164.9	5155.2	5156.8	5163.1	5171.1	5173.2	5173.3	5167.8
Energy Sales after Conservation	4749.7	4631.1	4710.4	4753.2	4745.9	4737.6	4737.0	4741.4	4748.7	4748.3	4745.2	4736.9	4721.8	4712.8	4714.3	4720.1	4727.4	4729.3	4729.4	4724.4
Total Customers (000's)	1,198	1,200	1,211	1,219	1,222	1,228	1,236	1,243	1,250	1,255	1,260	1,268	1,275	1,283	1,292	1,299	1,308	1,318	1,330	1,342
Net Electric Plant (M$)	5941.6	6486.7	6732.8	6906.9	7064.7	7236.4	7390.5	7555.7	7734.8	7942.0	8192.1	8494.3	8818.8	9167.0	9533.9	9909.5	10305.3	10716.9	11148.5	11596.7
Net Conservation Assets	11.9	40.4	79.2	131.7	194.2	272.1	321.7	373.3	429.1	501.4	604.6	746.5	897.0	1056.3	1218.9	1374.2	1532.3	1687.8	1843.1	1994.2
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.0	1930.5	2098.8	2180.0	2245.4	2267.0	2344.7	2402.7	2506.0	2590.6	2689.1	2786.9	2901.4	3036.7	3187.5	3349.5	3521.3	3669.1	3854.4	4037.1
Real	1910.0	1836.8	1900.0	1877.8	1840.3	1767.8	1739.7	1696.2	1683.3	1655.7	1635.2	1612.5	1597.3	1590.6	1588.6	1588.3	1588.8	1575.1	1574.4	1569.0
NPV (9.54% discount rate)	23864.1																			
Average Growth																				
Nominal	4.02%																			
Real	-1.03%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	47.5	50.9	52.4	54.0	54.5	56.5	57.8	60.2	62.1	64.7	67.2	70.1	73.4	77.2	81.0	85.0	88.3	93.0	97.5
Real	45.9	45.2	46.0	45.1	44.3	42.5	41.9	40.8	40.5	39.7	39.3	38.9	38.6	38.4	38.5	38.4	38.4	37.9	38.0	37.9
Average Growth																				
Nominal	4.05%																			
Real	-1.00%																			
Average Customer Bill ($)																				
Nominal	1594.5	1609.0	1732.6	1788.8	1837.4	1845.6	1896.8	1932.9	2005.4	2064.8	2134.4	2198.0	2275.4	2366.1	2467.2	2578.6	2692.3	2783.8	2897.3	3009.2
Real	1594.5	1530.9	1568.5	1540.8	1505.9	1439.2	1407.3	1364.5	1347.1	1319.6	1297.9	1271.7	1252.7	1239.4	1229.6	1222.8	1214.7	1195.1	1183.4	1169.5
NPV (9.54% discount rate)	19120.8																			
Customer Cost (M$)	2.8	2.6	3.2	3.6	3.8	1.8	1.9	1.8	2.1	2.0	2.5	3.3	3.6	4.3	9.5	16.7	34.2	48.2	70.8	86.2
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.5	0.9	1.2	1.6	1.8	2.0	2.2	2.4	2.6	2.9	3.2	3.6	4.0	5.0	6.7	10.2	15.1	22.3	31.1
NPV (9.54% discount rate)	32.6																			
Energy Services Charge (M$)	1.1	2.5	5.2	9.2	14.2	20.7	25.6	30.9	37.0	45.1	56.8	73.0	91.2	111.2	133.0	154.9	164.2	172.1	178.7	183.4
NPV (9.54% discount rate)	439.3																			
Total Resource Cost (M$)																				
Nominal	1911.4	1933.5	2104.9	2190.4	2261.3	2289.5	2372.3	2435.8	2545.3	2638.3	2748.8	2863.1	2996.2	3151.9	3325.5	3511.0	3695.7	3856.4	4055.4	4251.5
Real	1911.4	1839.6	1905.5	1886.8	1853.3	1785.4	1760.1	1719.5	1709.7	1686.2	1671.5	1656.6	1649.4	1651.0	1657.4	1664.9	1667.4	1655.5	1656.5	1652.3
NPV (9.54% discount rate)	24335.9																			
Average Growth																				
Nominal	4.30%																			
Real	-0.76%																			
Mills / KWh																				
Nominal	45.9	47.4	50.8	52.3	54.0	54.5	56.5	57.9	60.2	62.1	64.6	67.0	70.0	73.1	76.9	80.6	84.2	87.1	91.3	95.3
Real	45.9	45.1	46.0	45.1	44.3	42.5	41.9	40.8	40.4	39.7	39.3	38.8	38.5	38.3	38.3	38.2	38.0	37.4	37.3	37.0
Average Growth																				
Nominal	3.92%																			
Real	-1.12%																			

PacifiCorp Electric Operations
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Low Forecast

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,075	5,169	5,225	5,227	5,229	5,240	5,257	5,278	5,294	5,313	5,333	5,347	5,369	5,403	5,441	5,481	5,515	5,547	5,573	5,595
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,169	6,164	6,225	6,231	6,257	6,276	6,295	6,263	6,265	6,259	6,279	6,270	6,195	6,157	6,163	6,116	6,150	6,138	6,156	6,178
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	2	4	8	13	18	23	27	32	37	41	45	49	53	57	60	64	68	71	75	78
D.S. Options (1)	7	12	17	23	29	36	43	52	64	82	107	133	161	190	218	246	274	302	331	357
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
total	6,693	6,774	7,001	7,012	6,938	6,902	7,045	6,986	7,076	7,055	7,126	7,084	7,167	7,133	7,176	7,171	7,238	7,208	7,220	7,182
Balance	524	610	776	780	681	626	750	723	811	795	846	814	972	976	1,013	1,054	1,088	1,070	1,064	1,004

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Low Forecast

Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,587	6,712	6,784	6,783	6,783	6,793	6,812	6,837	6,856	6,878	6,902	6,918	6,945	6,990	7,038	7,091	7,137	7,179	7,214	7,241
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	7,864	7,965	8,037	8,040	7,942	7,952	7,971	7,996	7,965	7,987	8,011	8,027	7,854	7,799	7,839	7,692	7,738	7,780	7,740	7,767
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	2	6	11	18	25	32	39	46	53	59	65	71	78	84	90	96	102	108	114	120
D.S. Options (1)	8	14	21	29	41	53	67	82	103	134	177	223	270	319	367	415	463	511	559	603
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
total	9,473	9,851	10,138	10,332	10,259	10,162	10,589	10,622	10,621	10,651	10,709	10,758	10,776	10,836	10,761	10,833	10,843	10,898	10,786	10,853
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,300	1,300	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325
Balance	309	586	801	992	1,017	910	1,294	1,302	1,332	1,339	1,373	1,407	1,597	1,712	1,597	1,816	1,780	1,794	1,721	1,762
(Reserve+Balance)/Requirement	20%	24%	26%	29%	29%	28%	33%	33%	33%	33%	34%	34%	37%	39%	37%	41%	40%	40%	39%	40%

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Low Forecast

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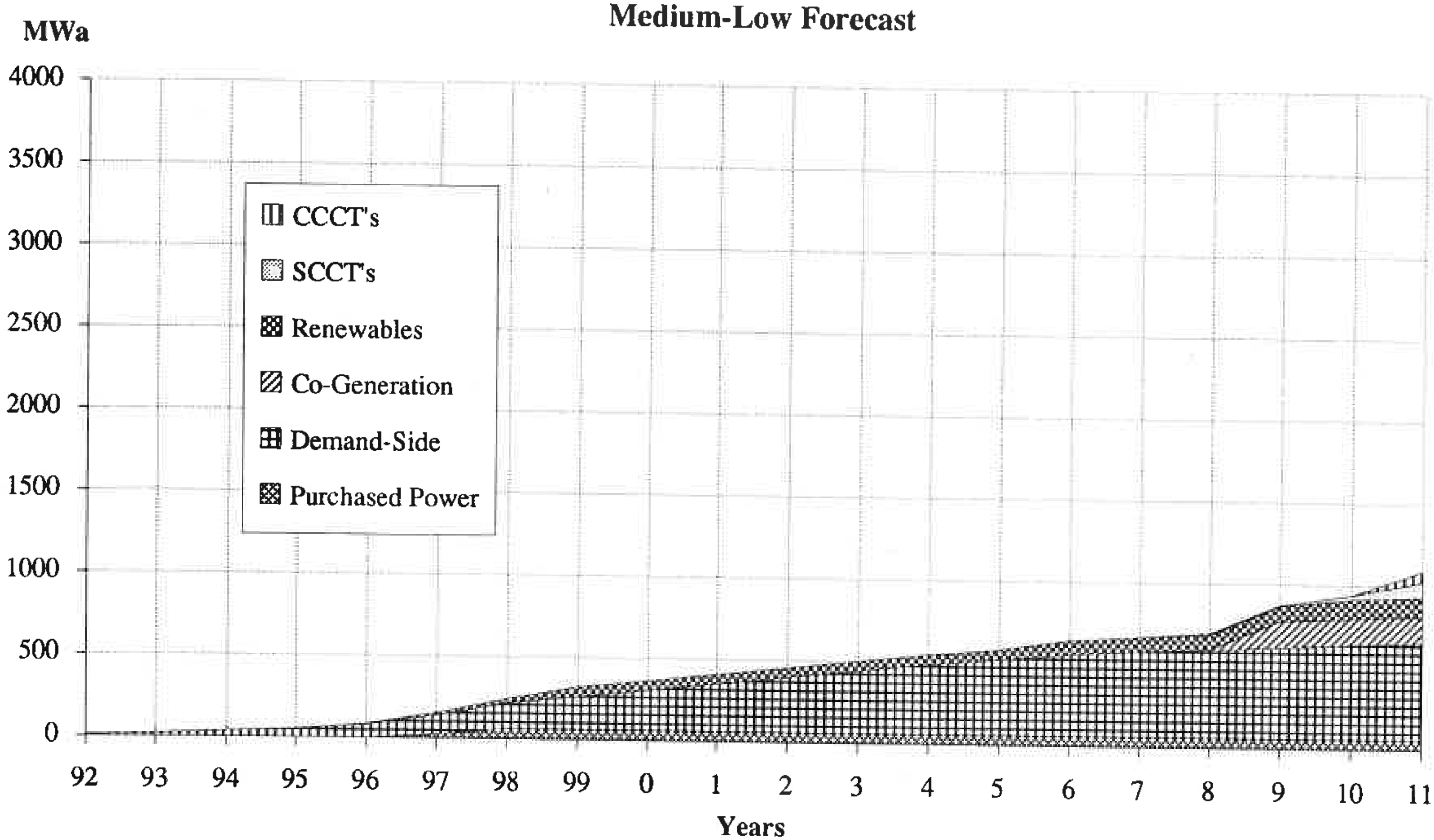
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,140	6,265	6,338	6,340	6,344	6,358	6,379	6,434	6,454	6,476	6,500	6,517	6,543	6,586	6,635	6,686	6,730	6,769	6,773	6,801
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	7,953	7,878	7,955	7,959	8,058	8,037	8,058	7,973	8,008	7,935	7,959	7,976	7,802	7,737	7,786	7,637	7,681	7,645	7,649	7,677
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	2	4	8	13	18	23	27	32	37	41	46	50	54	58	62	66	70	74	78	82
D.S. Options (1)	7	11	15	20	28	36	44	54	69	93	127	163	201	239	277	315	353	391	429	464
BPA Entitlement (1)																				
total	9,779	9,822	10,130	10,260	10,102	9,996	9,968	9,960	9,988	10,009	10,054	10,057	10,100	10,147	10,073	10,170	10,218	10,261	10,153	10,194
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,300	1,300	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,326	1,325	1,325	1,325	1,325
Balance	526	644	875	1,001	744	659	585	662	655	749	770	756	973	1,086	963	1,209	1,213	1,292	1,179	1,192
(Reserve+Balance)/Requirement	23%	25%	27%	29%	25%	24%	24%	25%	25%	26%	26%	26%	29%	31%	29%	33%	33%	34%	33%	33%

PacifiCorp - RAMPP 2

Illustrative Plan
Medium-Low Forecast



KEY OUTPUTS

Medium-Low Forecast

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5182.0	5386.0	5528.0	5589.0	5645.0	5708.0	5782.0	5862.0	5940.0	6022.0	6108.0	6189.0	6283.0	6393.0	6511.0	6631.0	6743.0	6850.0	6952.0
Total Conservation	4.5	9.9	20.7	35.5	55.5	82.8	115.9	156.1	198.9	242.7	287.4	332.9	378.0	422.1	460.3	492.1	515.6	535.7	554.3	572.0
System Load net of Conservation	5195.5	5172.1	5365.3	5492.5	5533.5	5562.2	5592.2	5625.9	5663.1	5697.3	5734.6	5775.1	5811.0	5861.0	5932.7	6018.9	6115.4	6207.3	6295.7	6380.0
Energy Sales after Conservation	4749.7	4728.4	4904.9	5021.3	5058.7	5085.0	5112.3	5143.2	5177.2	5208.5	5242.6	5279.6	5312.4	5358.1	5423.6	5502.4	5590.7	5674.7	5755.5	5832.6
Total Customers (000's)	1,207	1,218	1,240	1,259	1,274	1,290	1,309	1,327	1,344	1,361	1,377	1,397	1,416	1,437	1,458	1,478	1,500	1,524	1,551	1,576
Net Electric Plant (M$)	5944.2	6484.6	6745.4	6937.8	7130.7	7399.0	7721.4	8080.0	8401.0	8739.9	9096.0	9468.2	9849.0	10258.8	10761.7	11111.6	11454.5	11972.0	12922.7	13555.9
Net Conservation Assets	14.5	38.3	91.8	162.7	252.7	363.9	511.8	693.0	887.7	1086.8	1288.8	1491.3	1685.9	1868.7	2008.8	2097.5	2124.4	2118.2	2098.2	2069.5
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1911.1	1947.3	2130.6	2228.3	2305.8	2364.6	2476.1	2568.9	2741.5	2879.2	3033.4	3189.7	3369.6	3569.0	3794.6	4070.5	4335.8	4594.9	4886.1	5235.7
Real	1911.1	1852.8	1928.8	1919.4	1889.8	1843.9	1837.2	1813.6	1841.5	1840.1	1844.6	1845.5	1855.0	1869.4	1891.2	1930.2	1956.3	1972.5	1995.8	2034.8
NPV (9.54% discount rate)	26210.1																			
Average Growth																				
Nominal	5.45%																			
Real	0.33%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	46.9	49.6	50.7	52.0	52.9	55.3	57.0	60.4	62.9	66.1	69.0	72.4	75.8	79.9	84.4	88.5	92.2	96.9	102.5
Real	45.9	44.6	44.9	43.6	42.6	41.3	41.0	40.3	40.6	40.2	40.2	39.9	39.9	39.7	39.8	40.0	39.9	39.6	39.6	39.8
Average Growth																				
Nominal	4.31%																			
Real	-0.75%																			
Average Customer Bill ($)																				
Nominal	1584.0	1598.4	1718.1	1769.8	1810.4	1832.7	1892.1	1936.6	2039.5	2116.3	2202.6	2283.1	2379.3	2484.0	2602.4	2754.2	2890.1	3015.0	3151.3	3322.4
Real	1584.0	1520.8	1555.4	1524.4	1483.7	1429.2	1403.8	1367.2	1369.9	1352.5	1339.4	1320.9	1309.9	1301.1	1297.0	1306.0	1304.0	1294.3	1287.2	1291.2
NPV (9.54% discount rate)	19497.3																			
Customer Cost (M$)	2.8	2.8	3.6	4.2	4.8	3.1	3.2	3.6	3.3	1.9	0.9	-0.8	-1.2	-0.2	9.4	17.0	37.8	60.2	102.6	129.1
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	0.9	1.4	1.8	2.2	2.5	2.9	3.2	3.4	3.5	3.4	3.3	3.2	4.2	5.9	9.8	15.9	26.4	39.6
NPV (9.54% discount rate)	36.5																			
Energy Services Charge (M$)	0.9	2.4	6.4	11.9	19.5	29.0	43.3	61.7	82.2	104.0	126.9	150.8	175.2	200.7	225.7	247.9	251.3	249.8	247.7	243.4
NPV (9.54% discount rate)	748.0																			
Total Resource Cost (M$)																				
Nominal	1912.3	1950.2	2137.9	2241.6	2327.2	2395.7	2521.9	2633.5	2826.9	2986.6	3163.8	3343.8	3548.1	3772.9	4024.5	4324.3	4596.9	4860.6	5160.2	5518.8
Real	1912.3	1855.6	1935.5	1930.9	1907.3	1868.2	1871.2	1859.1	1898.8	1908.8	1923.9	1934.7	1953.3	1976.3	2005.7	2050.6	2074.0	2086.6	2107.7	2144.8
NPV (9.54% discount rate)	26994.5																			
Average Growth																				
Nominal	5.74%																			
Real	0.61%																			
Mills / KWh																				
Nominal	45.9	46.9	49.6	50.6	52.0	52.8	55.2	56.9	60.2	62.6	65.6	68.4	71.6	74.8	78.6	82.9	86.6	89.8	94.1	99.1
Real	45.9	44.6	44.9	43.6	42.6	41.2	40.9	40.1	40.4	40.0	39.9	39.6	39.4	39.2	39.2	39.3	39.1	38.5	38.4	38.5
Average Growth																				
Nominal	4.13%																			
Real	-0.92%																			

PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,182	5,386	5,528	5,589	5,645	5,708	5,782	5,862	5,940	6,022	6,108	6,189	6,283	6,393	6,511	6,631	6,743	6,850	6,952	7,040
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,276	6,381	6,528	6,593	6,673	6,744	6,820	6,847	6,911	6,968	7,054	7,112	7,109	7,147	7,233	7,266	7,378	7,441	7,535	7,623
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	2	5	11	17	25	32	39	47	54	62	69	76	83	90	96	103	110	117	124	131
D.S. Options (1)	8	15	25	38	58	84	117	152	188	226	264	302	340	371	396	412	425	437	448	458
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)							11	45	45	45	45	45	45	45	45	45	45	45	45	45
Wind-Pilot (1)					5	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Wind															30	30	30	30	30	30
Small CT																	8	8	8	8
CoGen																		80	80	80
CoGen																		80	80	80
Wind																			30	30
Small CT																			8	8
Small CT																			8	8
Medium CC CT																				64
Large CT																				31
Large CT (Jul)																				16
Large CT (Jul)																				16
Small CT																				8
total	6,694	6,778	7,011	7,031	6,979	6,975	7,157	7,161	7,279	7,280	7,367	7,340	7,435	7,407	7,481	7,466	7,531	7,647	7,691	7,775
Balance	418	397	482	438	306	231	337	314	368	311	313	228	326	260	247	200	153	206	156	152

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PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,731	7,004	7,191	7,270	7,341	7,422	7,518	7,624	7,726	7,834	7,947	8,052	8,177	8,325	8,482	8,643	8,794	8,939	9,077	9,194
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,008	8,257	8,444	8,527	8,500	8,581	8,677	8,783	8,835	8,943	9,056	9,161	9,086	9,134	9,283	9,244	9,395	9,540	9,603	9,720
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	2	7	15	24	35	45	56	67	78	89	100	111	121	133	143	155	166	178	189	199
D.S. Options (1)	9	20	34	55	89	133	190	251	314	379	445	512	575	627	669	696	718	737	755	771
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	50	50	50	50	50	50	50	50	50	50	50	50
Wind-Pilot (1)						16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Wind															32	32	32	32	32	32
Small CT																	40	40	40	40
CoGen																		94	94	94
CoGen																		94	94	94
Wind																			32	32
Small CT																			40	40
Small CT																			40	40
Medium CC CT																				128
Large CT																				156
Large CT (Jul)																				
Large CT (Jul)																				
Small CT																				40
total	9,474	9,858	10,154	10,363	10,317	10,271	10,746	10,878	10,924	10,991	11,078	11,152	11,190	11,258	11,214	11,270	11,299	11,519	11,494	11,862
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,300	1,302	1,327	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,339	1,339	1,345	1,373	1,390	1,439
Balance	166	301	410	536	517	388	742	761	754	714	687	657	770	790	592	687	559	606	500	704
(Reserve+Balance)/Requirement	18%	19%	20%	22%	21%	20%	24%	24%	24%	23%	22%	22%	23%	23%	21%	22%	20%	21%	20%	22%

PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast

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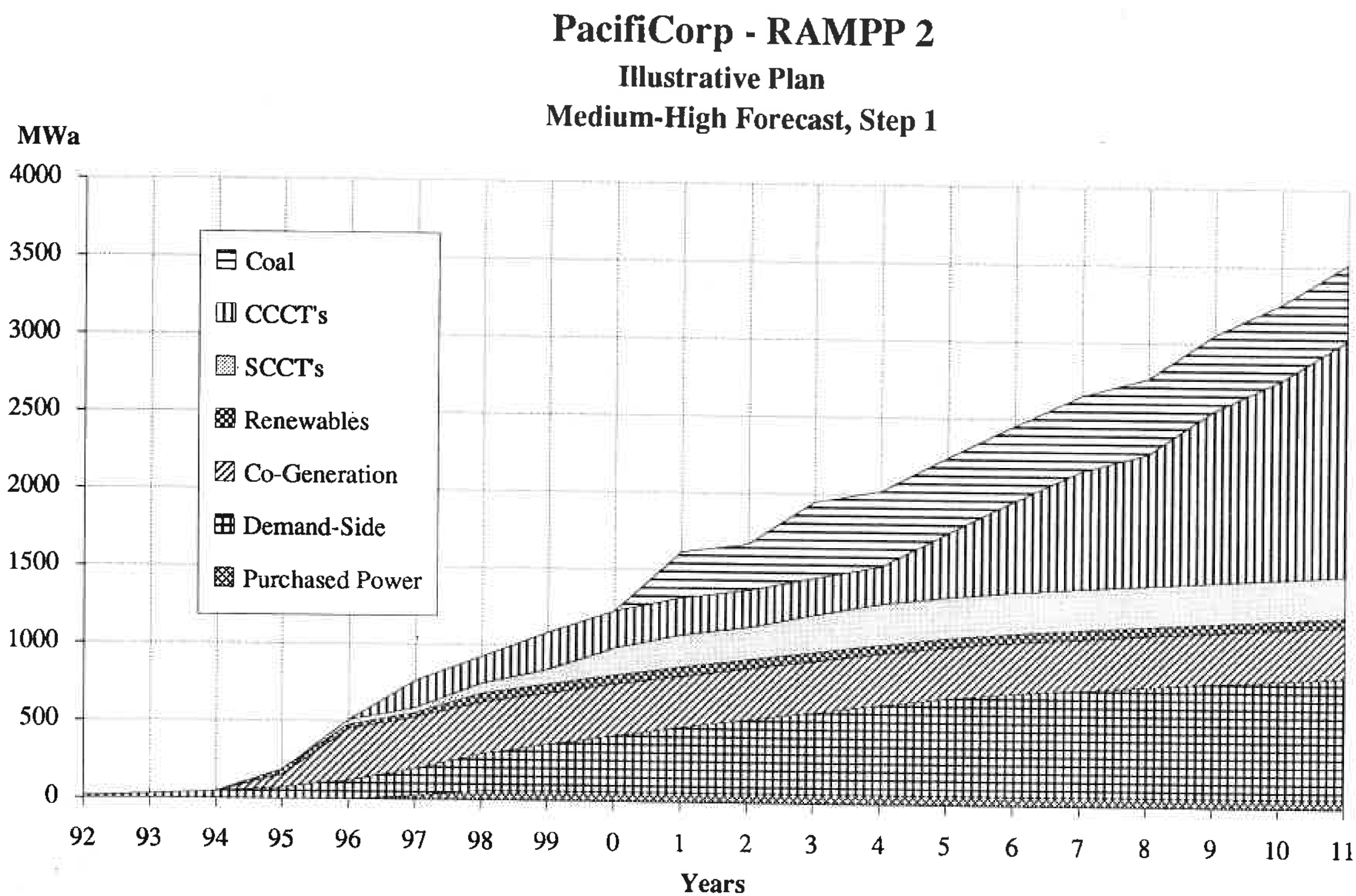
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,277	6,538	6,718	6,796	6,869	6,948	7,042	7,166	7,265	7,367	7,475	7,578	7,697	7,836	7,987	8,140	8,284	8,420	8,529	8,642
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,090	8,151	8,335	8,415	8,583	8,627	8,721	8,705	8,819	8,826	8,934	9,037	8,956	8,987	9,138	9,091	9,235	9,296	9,405	9,518
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	2	5	10	17	24	32	39	47	54	62	69	76	83	91	98	105	113	120	127	134
D.S. Options (1)	7	15	26	42	70	107	154	203	253	303	356	408	460	504	540	563	582	599	615	630
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	50	50	50	50	50	50	50	50	50	50	50	50
Wind-Pilot (1)						10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Wind															20	20	20	20	20	20
Small CT																	40	40	40	40
CoGen																		94	94	94
CoGen																		94	94	94
Wind																			20	20
Small CT																			40	40
Small CT																			40	40
Medium CC CT																				128
Large CT																				156
Large CT (Jul)																				156
Large CT (Jul)																				156
Small CT																				40
total	9,779	9,827	10,142	10,286	10,151	10,086	10,099	10,183	10,249	10,300	10,366	10,388	10,448	10,505	10,452	10,538	10,610	10,824	10,797	11,457
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,300	1,302	1,327	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,339	1,339	1,345	1,373	1,390	1,439
Balance	389	376	507	571	268	156	51	143	96	139	98	17	157	184	-25	107	30	154	2	500
(Reserve+Balance)/Requirement	21%	21%	22%	22%	18%	17%	16%	17%	16%	17%	16%	15%	17%	17%	14%	16%	15%	16%	15%	20%


PacifiCorp - RAMPP 2
Illustrative Plan
Medium-High Forecast, Step 1
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
Coal
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

Medium-High, Step 1

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6803.5	7207.4	7574.7	8077.3	8940.1	9963.9	11006.3	11819.9	12555.1	13312.7	13935.6	14640.0	15344.9	15998.3	16627.9	17321.2	17905.8	18261.8
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.6	2278.6	2398.5	2553.1	2739.9	2937.1	3204.9	3494.7	3863.3	4118.4	4568.8	4867.9	5288.8	5737.8	6259.6	6736.3	7265.2	7853.8
Real	1910.8	1887.7	1964.2	1962.7	1965.7	1990.9	2032.9	2073.5	2152.7	2233.5	2349.2	2382.9	2515.2	2549.8	2635.8	2720.8	2824.3	2891.8	2967.5	3052.3
NPV (9.54% discount rate)	31483.5																			
Average Growth																				
Nominal	7.72%																			
Real	2.50%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.7	52.5	55.3	58.0	61.7	65.4	70.6	73.4	79.4	82.4	87.8	92.7	98.7	103.5	109.5	115.7
Real	45.9	43.5	43.9	42.7	41.6	40.9	41.0	41.0	41.4	41.8	42.9	42.5	43.7	43.2	43.7	44.0	44.5	44.4	44.7	45.0
Average Growth																				
Nominal	4.98%																			
Real	-0.11%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1711.1	1768.4	1820.2	1888.4	1976.6	2071.6	2206.9	2353.7	2545.6	2650.9	2874.7	2999.3	3195.8	3405.4	3649.7	3854.4	4073.1	4315.0
Real	1566.3	1512.0	1549.0	1523.2	1491.8	1472.6	1466.5	1462.5	1482.4	1504.3	1548.0	1533.8	1582.6	1571.1	1592.7	1614.8	1646.7	1654.7	1663.7	1677.0
NPV (9.54% discount rate)	21449.9																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.1	2178.6	2294.5	2424.3	2591.9	2799.5	3021.4	3315.3	3632.6	4029.5	4315.1	4797.8	5131.2	5587.7	6066.9	6600.7	7090.8	7632.5	8234.1
Real	1912.2	1891.7	1972.3	1976.4	1986.9	2021.1	2077.1	2133.0	2226.9	2321.6	2450.3	2496.7	2641.3	2687.7	2784.8	2876.9	2978.2	3044.0	3117.6	3200.1
NPV (9.54% discount rate)	32500.7																			
Average Growth																				
Nominal	7.99%																			
Real	2.75%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.5	50.6	52.2	54.9	57.5	61.0	64.5	69.4	72.0	77.7	80.6	85.7	90.4	95.8	100.2	105.7	111.4
Real	45.9	43.4	43.9	42.6	41.5	40.7	40.7	40.6	41.0	41.2	42.2	41.7	42.8	42.2	42.7	42.8	43.2	43.0	43.2	43.3
Average Growth																				
Nominal	4.77%																			
Real	-0.31%																			

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PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Med-High Step 1

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946 [1]	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
Wind (1)				30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CT (1)					31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Wind (2)							30	30	30	30	30	30	30	30	30	30	30	30	30	30
Hunter 4 (1)										300	300	300	300	300	300	300	300	300	300	300
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CC CT (1)								64	64	64	64	64	64	64	64	64	64	64	64	64
Large CT (3)								31	31	31	31	31	31	31	31	31	31	31	31	31
Wyodak 2 (1)												192	192	192	192	192	192	192	192	192
Large CT (4)									31	31	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (1)									16	31	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (2)									16	31	31	31	31	31	31	31	31	31	31	31
Medium CT (1)									20	20	20	20	20	20	20	20	20	20	20	20
Small CT (1)												8	8	8	8	8	8	8	8	8
Small CT (2)												8	8	8	8	8	8	8	8	8
Small CT (Jul) (1)												4	8	8	8	8	8	8	8	8
Small CT (Jul) (2)												4	8	8	8	8	8	8	8	8
Small CT (Jul) (3)												4	8	8	8	8	8	8	8	8
Small CT (Jul) (4)												4	8	8	8	8	8	8	8	8
Small CT													8	8	8	8	8	8	8	8
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT																175	175	175	175	175
Large CC CT (Jul)																	88	175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Large CC CT																				175
Medium CC CT																				64
total	6,697	6,784	7,021	7,162	7,403	7,584	7,839	7,925	8,143	8,487	8,583	8,787	8,913	9,069	9,292	9,455	9,604	9,829	10,007	10,202
Balance	180	179	229	179	195	182	244	152	154	291	156	153	156	169	186	216	155	217	191	167

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PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Med-High Step 1

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,056	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
Wind (1)				32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wind (2)							32	32	32	32	32	32	32	32	32	32	32	32	32	32
Hunter 4 (1)										400	400	400	400	400	400	400	400	400	400	400
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CC CT (1)								128	128	128	128	128	128	128	128	128	128	128	128	128
Large CT (3)								156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)												256	256	256	256	256	256	256	256	256
Large CT (4)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)										156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (2)										156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
Small CT (1)												40	40	40	40	40	40	40	40	40
Small CT (2)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)													40	40	40	40	40	40	40	40
Small CT (Jul) (2)													40	40	40	40	40	40	40	40
Small CT (Jul) (3)													40	40	40	40	40	40	40	40
Small CT (Jul) (4)													40	40	40	40	40	40	40	40
Small CT													40	40	40	40	40	40	40	40
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT (Jul)																		250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Medium CC CT																				128
total	9,479	9,865	10,167	10,514	10,945	11,169	11,870	12,271	12,600	13,399	13,496	13,914	14,161	14,494	14,676	14,985	14,983	15,524	15,647	16,082
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,319	1,386	1,424	1,477	1,519	1,558	1,664	1,664	1,715	1,745	1,782	1,820	1,857	1,857	1,932	1,970	2,027
Balance	-153	13	77	152	344	281	676	726	763	1,146	937	997	1,122	1,230	1,069	1,250	970	1,162	1,039	1,124
(Reserve+Balance)/Requirement	14%	15%	16%	16%	19%	18%	22%	22%	23%	27%	24%	24%	25%	26%	25%	26%	23%	25%	24%	24%

PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Med-High Step 1

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Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
Wind (1)				20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
BPA Entitlement (1)																				
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wind (2)							20	20	20	20	20	20	20	20	20	20	20	20	20	20
Hunter 4 (1)										400	400	400	400	400	400	400	400	400	400	400
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CC CT (1)								128	128	128	128	128	128	128	128	128	128	128	128	128
Large CT (3)								156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)												256	256	256	256	256	256	256	256	256
Large CT (4)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (2)									156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
Small CT (1)												40	40	40	40	40	40	40	40	40
Small CT (2)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (4)												40	40	40	40	40	40	40	40	40
Small CT													40	40	40	40	40	40	40	40
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT (Jul)																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Medium CC CT																				128
total	9,783	9,833	10,154	10,421	10,758	10,962	11,182	11,528	12,187	12,658	12,740	13,271	13,384	13,705	13,891	14,231	14,520	14,804	14,936	15,347
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,319	1,386	1,424	1,477	1,519	1,558	1,664	1,664	1,715	1,745	1,782	1,820	1,857	1,857	1,932	1,970	2,027
Balance	81	93	176	181	96	57	-20	100	410	569	355	540	539	655	495	712	731	750	603	674
(Reserve+Balance)/Requirement	16%	17%	17%	17%	16%	16%	15%	16%	19%	21%	19%	20%	21%	22%	20%	22%	22%	22%	21%	21%

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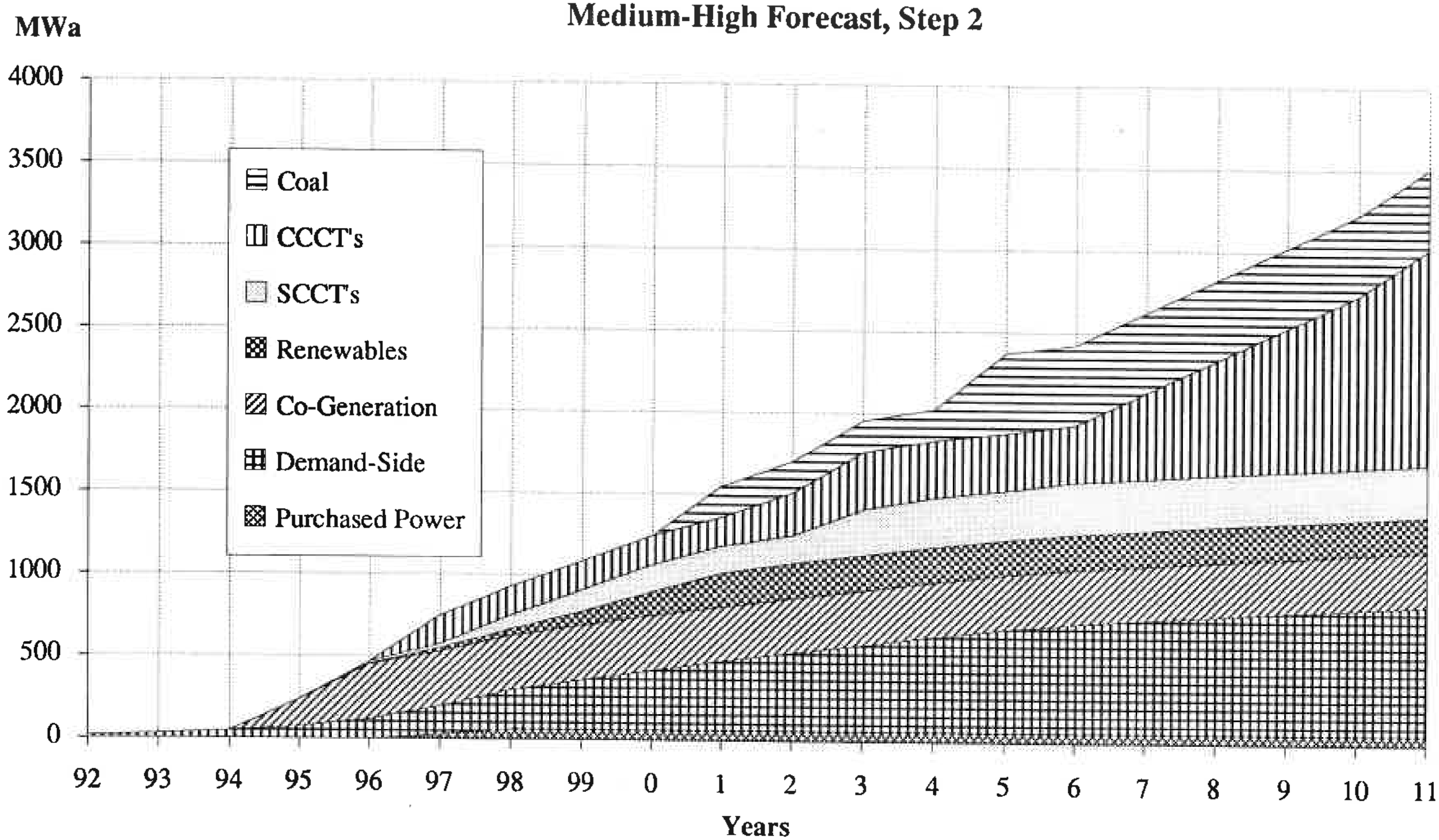
PacifiCorp - RAMPP 2

Illustrative Plan

Medium-High Forecast, Step 2



KEY OUTPUTS

Medium-High, Step 2

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485
Net Electric Plant (M$)	5945.7	6497.1	6789.2	7111.0	7482.5	8033.7	8885.5	9798.8	10745.6	11634.3
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)										
Nominal	1910.8	1984.0	2169.4	2277.2	2377.8	2531.9	2728.6	2944.3	3223.5	3492.8
Real	1910.8	1887.7	1964.0	1961.5	1948.8	1974.4	2024.5	2078.6	2165.3	2232.3
NPV (9.54% discount rate)	31644.3									
Average Growth										
Nominal	7.77%									
Real	2.54%									
Base Unit Cost (mills/kwh)										
Nominal	45.9	45.7	48.5	49.5	50.3	52.0	55.0	58.2	62.0	65.3
Real	45.9	43.5	43.9	42.6	41.2	40.6	40.8	41.1	41.7	41.8
Average Growth										
Nominal	5.03%									
Real	-0.07%									
Average Customer Bill ($)										
Nominal	1566.3	1589.1	1710.9	1767.3	1804.5	1872.7	1968.4	2076.7	2219.8	2352.3
Real	1566.3	1512.0	1548.9	1522.3	1479.0	1460.3	1460.5	1466.1	1491.0	1503.4
NPV (9.54% discount rate)	21543.2									
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3
Levelized Customer Cost (M$)										
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2
NPV (9.54% discount rate)	41.0									
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1
NPV (9.54% discount rate)	976.3									
Total Resource Cost (M$)										
Nominal	1912.2	1988.1	2178.4	2293.1	2403.7	2570.6	2788.2	3028.6	3334.0	3630.6
Real	1912.2	1891.7	1972.1	1975.2	1970.0	2004.6	2068.7	2138.1	2239.5	2320.4
NPV (9.54% discount rate)	32661.5									
Average Growth										
Nominal	8.03%									
Real	2.79%									
Mills / KWh										
Nominal	45.9	45.7	48.5	49.4	50.2	51.8	54.7	57.7	61.3	64.4
Real	45.9	43.4	43.9	42.6	41.1	40.4	40.6	40.7	41.2	41.2
Average Growth										
Nominal	4.82%									
Real	-0.27%									

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	12619.8	13548.8	14301.0	15053.0	15698.0	16340.8	16973.0	17705.7	18343.0	18722.1
Net Conservation Assets	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues Nominal	3889.2	4209.6	4603.6	4922.6	5410.6	5820.1	6337.8	6799.1	7336.3	7920.9
Operating Revenues Real	2365.0	2435.6	2534.3	2578.4	2696.5	2759.9	2859.5	2918.8	2996.6	3078.4
Base Unit Cost Nominal	71.1	75.0	80.0	83.3	89.8	94.1	99.9	104.5	110.6	116.7
Base Unit Cost Real	43.2	43.4	44.0	43.7	44.8	44.6	45.1	44.9	45.2	45.4
Average Customer Bill Nominal	2562.7	2709.6	2896.6	3033.0	3269.4	3454.3	3695.3	3890.3	4113.0	4351.9
Average Customer Bill Real	1558.4	1567.7	1594.6	1588.7	1629.4	1638.0	1667.3	1670.1	1680.0	1691.3
Customer Cost (M$)	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
Energy Services Charge (M$)	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
Total Resource Cost Nominal	4055.5	4406.3	4832.6	5185.9	5709.5	6149.2	6678.9	7153.6	7703.6	8301.2
Total Resource Cost Real	2466.1	2549.4	2660.4	2716.3	2845.5	2916.0	3013.4	3071.0	3146.6	3226.2
Mills / KWh Nominal	69.8	73.6	78.3	81.4	87.5	91.6	96.9	101.1	106.6	112.3
Mills / KWh Real	42.5	42.6	43.1	42.7	43.6	43.4	43.7	43.4	43.6	43.6

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium-High Step 2

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196
Resources										
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316
Firm Purchases	612	632	675	682	554	535	566	558	556	551
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328
BPA Entitlement (1)						26	65	65	65	65
Geothermal-Pilot (1)								45	90	135
Wind-Pilot (1)					5	22	38	42	58	73
CoGen (1)				80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8
Small CT (Jul) (3)					4	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175
Wyodak 2 (1)										192
Large CT (1)							31	31	31	31
Large CT (2)							31	31	31	31
Small CT (1)								8	8	8
Large CT (3)								31	31	31
Small CT (Jul) (4)								4	8	8
Large CT (4)									31	31
Hunter 4 (1)										
Large CC CT (Jul) (1)										
Large CT (5)										
Large CT (6)										
Large CT (7)										
Medium CT (1)										
Medium CT										
Small CT										
Small CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
total	6,697	6,784	7,021	7,211	7,358	7,569	7,840	7,925	8,155	8,420
Balance	180	179	229	229	150	167	245	151	166	224

Average Megawatts	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	946	923	826	754	722	635	635	591	583	583
total	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources										
Existing Generation	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)	83	83	83	83	83	83	83	83	83	83
CoGen (1)	80	80	80	80	80	80	80	80	80	80
CoGen (2)	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)	175	175	175	175	175	175	175	175	175	175
Wyodak 2 (1)	192	192	192	192	192	192	192	192	192	192
Large CT (1)	31	31	31	31	31	31	31	31	31	31
Large CT (2)	31	31	31	31	31	31	31	31	31	31
Small CT (1)	8	8	8	8	8	8	8	8	8	8
Large CT (3)	31	31	31	31	31	31	31	31	31	31
Small CT (Jul) (4)	8	8	8	8	8	8	8	8	8	8
Large CT (4)	31	31	31	31	31	31	31	31	31	31
Hunter 4 (1)				300	300	300	300	300	300	300
Large CC CT (Jul) (1)	88	175	175	175	175	175	175	175	175	175
Large CT (5)		31	31	31	31	31	31	31	31	31
Large CT (6)		31	31	31	31	31	31	31	31	31
Large CT (7)		31	31	31	31	31	31	31	31	31
Medium CT (1)		20	20	20	20	20	20	20	20	20
Medium CT			20	20	20	20	20	20	20	20
Small CT					8	8	8	8	8	8
Small CT					8	8	8	8	8	8
Large CC CT						175	175	175	175	175
Large CC CT							175	175	175	175
Large CC CT								175	175	175
Large CC CT									175	175
Large CC CT										175
Large CC CT (Jul)										88
total	8,614	8,795	8,917	9,198	9,262	9,425	9,661	9,799	9,977	10,197
Balance	188	161	160	298	156	185	212	187	161	161

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium-High Step 2

4/1/92 10:22

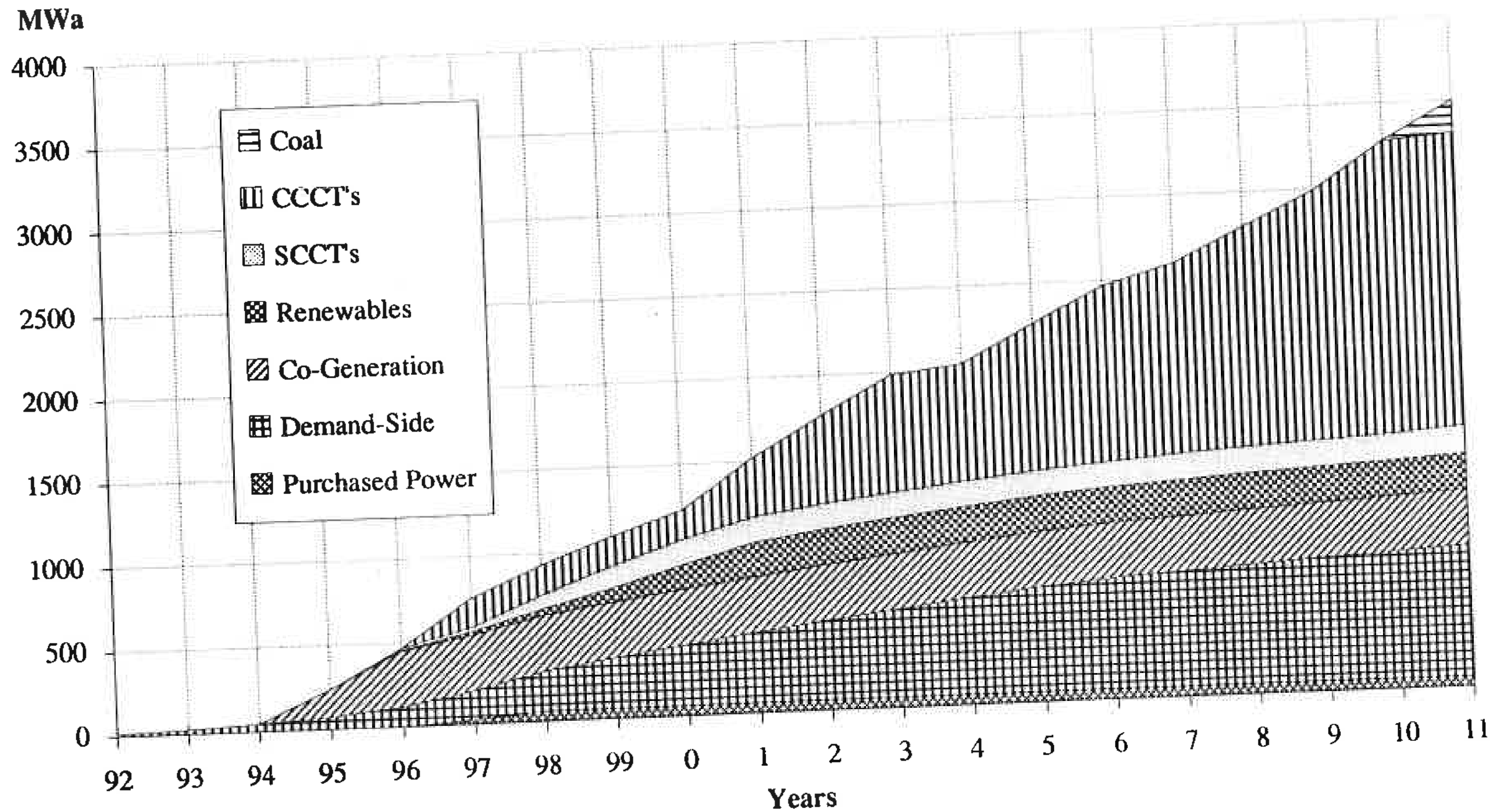
Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (3)								156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (Jul) (4)									40	40	40	40	40	40	40	40	40	40	40	40
Large CT (4)									156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)														400	400	400	400	400	400	400
Large CC CT (Jul) (1)												250	250	250	250	250	250	250	250	250
Large CT (5)												156	156	156	156	156	156	156	156	156
Large CT (6)												156	156	156	156	156	156	156	156	156
Large CT (7)												156	156	156	156	156	156	156	156	156
Medium CT (1)												100	100	100	100	100	100	100	100	100
Medium CT													100	100	100	100	100	100	100	100
Small CT															40	40	40	40	40	40
Small CT															40	40	40	40	40	40
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT (Jul)																				
total	9,479	9,865	10,167	10,577	10,757	11,117	11,966	12,329	12,665	13,073	13,185	14,086	14,233	14,715	14,727	15,037	15,285	15,576	15,699	16,005
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,528	1,567	1,615	1,618	1,741	1,756	1,816	1,828	1,865	1,903	1,940	1,978	2,015
Balance	-153	13	77	206	184	237	758	775	817	869	673	1,143	1,183	1,419	1,113	1,294	1,226	1,206	1,082	1,059
(Reserve+Balance)/Requirement	14%	15%	16%	17%	17%	17%	23%	23%	23%	23%	21%	26%	26%	28%	25%	27%	26%	25%	24%	24%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium-High Step 2

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (3)								156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (Jul) (4)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (4)									156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)														400	400	400	400	400	400	400
Large CC CT (Jul) (1)											250	250	250	250	250	250	250	250	250	250
Large CT (5)												156	156	156	156	156	156	156	156	156
Large CT (6)												156	156	156	156	156	156	156	156	156
Large CT (7)												156	156	156	156	156	156	156	156	156
Medium CT (1)												100	100	100	100	100	100	100	100	100
Medium CT													100	100	100	100	100	100	100	100
Small CT															40	40	40	40	40	40
Small CT															40	40	40	40	40	40
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT (Jul)																				250
total	9,783	9,833	10,154	10,495	10,702	10,916	11,287	11,635	11,942	12,329	12,671	13,274	13,447	13,918	13,934	14,274	14,563	14,847	14,979	15,512
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,528	1,567	1,615	1,618	1,741	1,756	1,816	1,828	1,865	1,903	1,940	1,978	2,015
Balance	81	93	176	246	68	19	71	199	156	289	333	518	592	835	530	747	729	785	638	850
(Reserve+Balance)/Requirement	16%	17%	17%	18%	15%	15%	16%	17%	17%	18%	18%	20%	21%	24%	20%	22%	22%	22%	21%	23%

PacifiCorp - RAMPP 2

Illustrative Plan
Medium-High Forecast, Step 3



KEY OUTPUTS
Medium-High, Step 3

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6789.2	7111.0	7482.5	7983.9	8695.1	9469.5	10331.6	11130.8	11768.8	12326.5	12957.6	13694.0	14450.8	15232.4	16079.6	16903.8	17618.0	18098.8
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.4	2277.2	2377.8	2531.2	2726.2	2940.2	3218.0	3476.3	3810.7	4127.0	4477.2	4778.3	5212.7	5681.0	6237.3	6719.2	7277.6	7877.4
Real	1910.8	1887.7	1964.0	1961.5	1948.8	1973.9	2022.8	2075.7	2161.5	2221.8	2317.3	2387.8	2464.8	2502.9	2597.9	2693.9	2814.2	2884.5	2972.6	3061.5
NPV (9.54% discount rate)	31331.9																			
Average Growth																				
Nominal	7.74%																			
Real	2.51%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.3	52.0	55.0	58.1	61.9	65.0	69.6	73.5	77.8	80.9	86.5	91.8	98.3	103.3	109.7	116.1
Real	45.9	43.5	43.9	42.6	41.2	40.6	40.8	41.0	41.6	41.6	42.4	42.5	42.8	42.4	43.1	43.5	44.4	44.3	44.8	45.1
Average Growth																				
Nominal	5.00%																			
Real	-0.09%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1710.9	1767.3	1804.5	1872.2	1966.7	2073.8	2215.9	2341.3	2511.0	2656.4	2817.1	2944.1	3149.8	3371.7	3636.7	3844.6	4080.0	4328.0
Real	1566.3	1512.0	1548.9	1522.3	1479.0	1460.0	1459.2	1464.0	1488.4	1496.3	1526.9	1537.0	1550.8	1542.1	1569.8	1598.8	1640.8	1650.5	1666.5	1682.0
NPV (9.54% discount rate)	21351.1																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.1	2178.4	2293.1	2403.7	2570.0	2785.8	3024.5	3328.4	3614.2	3977.0	4323.7	4706.2	5041.6	5511.6	6010.1	6578.4	7073.7	7644.9	8257.8
Real	1912.2	1891.7	1972.1	1975.2	1970.0	2004.1	2067.0	2135.2	2235.7	2309.9	2418.4	2501.7	2590.8	2640.8	2746.9	2850.0	2968.1	3036.7	3122.7	3209.3
NPV (9.54% discount rate)	32349.1																			
Average Growth																				
Nominal	8.00%																			
Real	2.76%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.2	51.8	54.6	57.6	61.2	64.1	68.5	72.2	76.2	79.2	84.5	89.5	95.5	99.9	105.8	111.7
Real	45.9	43.4	43.9	42.6	41.1	40.4	40.5	40.7	41.1	41.0	41.7	41.8	42.0	41.5	42.1	42.4	43.1	42.9	43.2	43.4
Average Growth																				
Nominal	4.79%																			
Real	-0.30%																			

Power Planning 4/22/92 9:53 AM

sdc Key Outputs - MH Step 3 4/17

PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Med-High Step 3

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Small CT (1)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (2)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (3)								8	8	8	8	8	8	8	8	8	8	8	8	8
Medium CT (1)								20	20	20	20	20	20	20	20	20	20	20	20	20
Medium CT (2)									20	20	20	20	20	20	20	20	20	20	20	20
Large CC CT (2)										175	175	175	175	175	175	175	175	175	175	175
Large CC CT (3)											175	175	175	175	175	175	175	175	175	175
Large CC CT (4)												175	175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT (Jul)																88	175	175	175	175
Small CT																8	8	8	8	8
Large CC CT (Jul)																	88	175	175	175
Large CC CT (Jul)																		88	175	175
Large CC CT																			175	175
Wyodak 2																				192
Medium CT (Jul)																				10
total	6,697	6,784	7,021	7,211	7,358	7,569	7,840	7,925	8,140	8,389	8,670	8,825	8,927	9,083	9,306	9,390	9,626	9,764	10,029	10,187
Balance	180	179	229	229	150	167	245	152	151	192	243	191	170	183	200	151	177	152	213	151

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PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Med-High Step 3

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Winter Peak

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588
Resources										
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545
BPA Entitlement (1)							164	164	164	164
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						16	39	39	55	71
CoGen (1)				94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40
Large CC CT (1)						250	250	250	250	250
Large CT (1)							156	156	156	156
Large CT (2)							156	156	156	156
Small CT (1)								40	40	40
Small CT (2)								40	40	40
Small CT (3)								40	40	40
Medium CT (1)								100	100	100
Medium CT (2)									100	100
Large CC CT (2)										250
Large CC CT (3)										
Large CC CT (4)										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
Small CT										
Large CC CT (Jul)										
Large CC CT (Jul)										
Large CC CT										
Wyodak 2										
Medium CT (Jul)										
total	9,479	9,865	10,167	10,577	10,757	11,117	11,966	12,353	12,593	12,995
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,556	1,604
Balance	-153	13	77	206	184	237	758	796	756	803
(Reserve+Balance)/Requirement	14%	15%	16%	17%	17%	17%	23%	23%	22%	23%

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,109	1,109	909	809	801	601	601	601	526	526
total	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources										
Existing Generation	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	87	87	87	87	87	87	87	87	87	87
CoGen (1)	94	94	94	94	94	94	94	94	94	94
CoGen (2)	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Large CT (2)	156	156	156	156	156	156	156	156	156	156
Small CT (1)	40	40	40	40	40	40	40	40	40	40
Small CT (2)	40	40	40	40	40	40	40	40	40	40
Small CT (3)	40	40	40	40	40	40	40	40	40	40
Medium CT (1)	100	100	100	100	100	100	100	100	100	100
Medium CT (2)	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)	250	250	250	250	250	250	250	250	250	250
Large CC CT (4)		250	250	250	250	250	250	250	250	250
Large CC CT				250	250	250	250	250	250	250
Large CC CT					250	250	250	250	250	250
Large CC CT (Jul)							250	250	250	250
Small CT						40	40	40	40	40
Large CC CT (Jul)								250	250	250
Large CC CT (Jul)									250	250
Large CC CT									250	250
Wyodak 2										256
Medium CT (Jul)										
total	13,357	13,690	13,737	14,069	14,251	14,351	14,599	14,890	15,263	15,575
Reserve Requirement										
Total Company Reserve	1,644	1,681	1,681	1,719	1,756	1,762	1,800	1,837	1,912	1,951
Balance	820	807	762	870	708	711	643	623	712	694
(Reserve+Balance)/Requirement	23%	22%	22%	23%	21%	21%	20%	20%	21%	20%

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PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Med-High Step 3

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196
Resources										
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316
Firm Purchases	612	632	675	682	554	535	566	558	556	551
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328
BPA Entitlement (1)						26	65	65	65	65
Geothermal-Pilot (1)								45	90	135
Wind-Pilot (1)					5	22	38	42	58	73
CoGen (1)				80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8
Small CT (Jul) (3)					4	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175
Large CT (1)							31	31	31	31
Large CT (2)							31	31	31	31
Small CT (1)								8	8	8
Small CT (2)								8	8	8
Small CT (3)								8	8	8
Medium CT (1)								20	20	20
Medium CT (2)									20	20
Large CC CT (2)										175
Large CC CT (3)										
Large CC CT (4)										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
Small CT										
Large CC CT (Jul)										
Large CC CT (Jul)										
Large CC CT										
Wyodak 2										
Medium CT (Jul)										
total	6,697	6,784	7,021	7,211	7,358	7,569	7,840	7,925	8,140	8,389
Balance	180	179	229	229	150	167	245	152	151	192

Average Megawatts	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	946	923	826	754	722	635	635	591	583	583
total	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources										
Existing Generation	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)	83	83	83	83	83	83	83	83	83	83
CoGen (1)	80	80	80	80	80	80	80	80	80	80
CoGen (2)	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)	175	175	175	175	175	175	175	175	175	175
Large CT (1)	31	31	31	31	31	31	31	31	31	31
Large CT (2)	31	31	31	31	31	31	31	31	31	31
Small CT (1)	8	8	8	8	8	8	8	8	8	8
Small CT (2)	8	8	8	8	8	8	8	8	8	8
Small CT (3)	8	8	8	8	8	8	8	8	8	8
Medium CT (1)	20	20	20	20	20	20	20	20	20	20
Medium CT (2)	20	20	20	20	20	20	20	20	20	20
Large CC CT (2)	175	175	175	175	175	175	175	175	175	175
Large CC CT (3)	175	175	175	175	175	175	175	175	175	175
Large CC CT (4)		175	175	175	175	175	175	175	175	175
Large CC CT				175	175	175	175	175	175	175
Large CC CT					175	175	175	175	175	175
Large CC CT (Jul)						88	175	175	175	175
Small CT						8	8	8	8	8
Large CC CT (Jul)							88	175	175	175
Large CC CT (Jul)								88	175	175
Large CC CT									175	175
Wyodak 2										192
Medium CT (Jul)										10
total	8,670	8,825	8,927	9,083	9,306	9,390	9,626	9,764	10,029	10,187
Balance	243	191	170	183	200	151	177	152	213	151

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PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Med-High Step 3

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (2)									100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)											250	250	250	250	250	250	250	250	250	250
Large CC CT (4)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																	250	250	250	250
Small CT																40	40	40	40	40
Large CC CT (Jul)																		250	250	250
Large CC CT (Jul)																			250	250
Large CC CT																			250	250
Wyodak 2																				256
Medium CT (Jul)																				
total	9,479	9,865	10,167	10,577	10,757	11,117	11,966	12,353	12,593	12,995	13,357	13,690	13,737	14,069	14,251	14,351	14,599	14,890	15,263	15,575
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,556	1,604	1,644	1,681	1,681	1,719	1,756	1,762	1,800	1,837	1,912	1,951
Balance	-153	13	77	206	184	237	758	796	756	803	820	807	762	870	708	711	643	623	712	694
(Reserve+Balance)/Requirement	14%	15%	16%	17%	17%	17%	23%	23%	22%	23%	23%	22%	22%	23%	21%	21%	20%	20%	21%	20%

PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Med-High Step 3

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424
Resources										
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452
BPA Entitlement (1)										
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						10	25	25	35	45
CoGen (1)				94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40
Small CT (Jul) (2)					40	40	40	40	40	40
Small CT (Jul) (3)					40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250
Large CT (1)							156	156	156	156
Large CT (2)							156	156	156	156
Small CT (1)								40	40	40
Small CT (2)								40	40	40
Small CT (3)								40	40	40
Medium CT (1)								100	100	100
Medium CT (2)									100	100
Large CC CT (2)										250
Large CC CT (3)										
Large CC CT (4)										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
Small CT										
Large CC CT (Jul)										
Large CC CT (Jul)										
Large CC CT										
Wyodak 2										
Medium CT (Jul)										
total	9,783	9,833	10,154	10,495	10,702	10,916	11,287	11,619	11,870	12,251
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,556	1,604
Balance	81	93	176	246	68	19	71	179	95	223
(Reserve+Balance)/Requirement	16%	17%	17%	18%	15%	15%	16%	17%	16%	18%

Summer Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources										
Existing Generation	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)										
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	55	55	55	55	55	55	55	55	55	55
CoGen (1)	94	94	94	94	94	94	94	94	94	94
CoGen (2)	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Large CT (2)	156	156	156	156	156	156	156	156	156	156
Small CT (1)	40	40	40	40	40	40	40	40	40	40
Small CT (2)	40	40	40	40	40	40	40	40	40	40
Small CT (3)	40	40	40	40	40	40	40	40	40	40
Medium CT (1)	100	100	100	100	100	100	100	100	100	100
Medium CT (2)	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)	250	250	250	250	250	250	250	250	250	250
Large CC CT (4)		250	250	250	250	250	250	250	250	250
Large CC CT				250	250	250	250	250	250	250
Large CC CT					250	250	250	250	250	250
Large CC CT (Jul)						250	250	250	250	250
Small CT						40	40	40	40	40
Large CC CT (Jul)							250	250	250	250
Large CC CT (Jul)								250	250	250
Large CC CT									250	250
Wyodak 2										256
Medium CT (Jul)										100
total	12,593	12,878	12,951	13,272	13,458	13,838	14,127	14,411	14,543	14,932
Reserve Requirement										
Total Company Reserve	1,644	1,681	1,681	1,719	1,756	1,762	1,800	1,837	1,912	1,951
Balance	229	181	170	286	125	414	396	452	267	335
(Reserve+Balance)/Requirement	17%	17%	17%	18%	16%	19%	18%	19%	18%	18%

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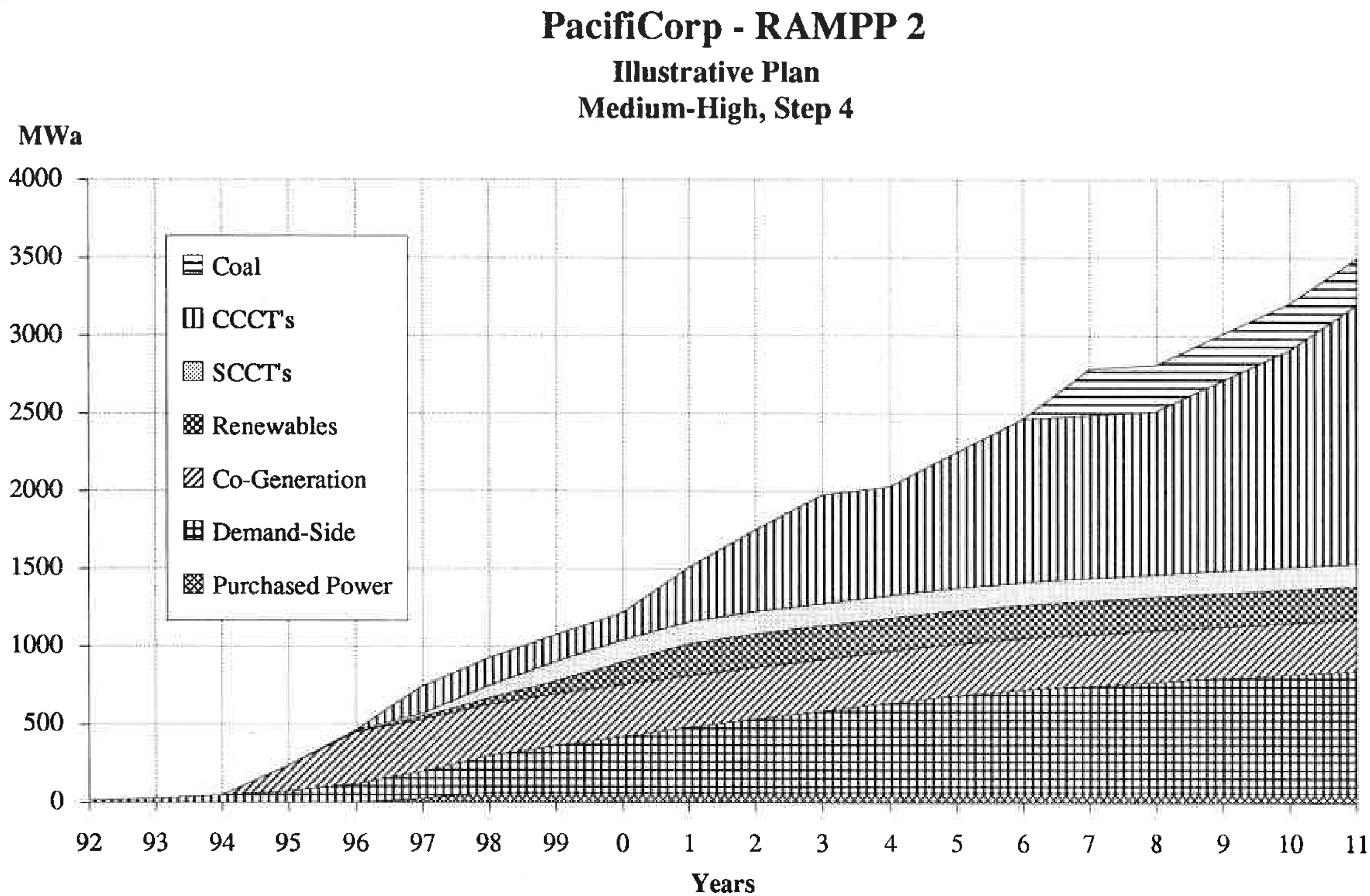

PacifiCorp - RAMPP 2
Illustrative Plan
Medium-High, Step 4
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
Coal
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

Medium High, Step 4

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6786.4	7093.5	7452.5	7951.6	8646.3	9473.5	10335.8	11135.1	11773.3	12422.0	13313.4	14270.6	15112.6	15790.8	16346.1	17105.9	17770.4	18176.8
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.4	2276.9	2377.4	2525.3	2719.9	2934.9	3218.2	3476.9	3809.3	4129.2	4482.5	4787.6	5219.0	5689.6	6283.4	6693.2	7236.6	7828.3
Real	1910.8	1887.7	1963.9	1961.3	1948.5	1969.2	2018.1	2071.9	2161.7	2222.1	2316.5	2389.1	2467.7	2507.7	2601.1	2698.0	2835.0	2873.4	2955.9	3042.4
NPV (9.54% discount rate)	31318.9																			
Average Growth																				
Nominal	7.70%																			
Real	2.48%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.3	51.9	54.8	58.0	61.9	65.0	69.6	73.6	77.9	81.0	86.6	92.0	99.1	102.9	109.1	115.3
Real	45.9	43.5	43.9	42.6	41.2	40.5	40.7	40.9	41.6	41.6	42.3	42.6	42.9	42.5	43.2	43.6	44.7	44.2	44.5	44.8
Average Growth																				
Nominal	4.97%																			
Real	-0.13%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1710.9	1767.1	1804.2	1867.8	1962.1	2070.1	2216.1	2341.7	2510.1	2657.8	2820.4	2949.8	3153.7	3376.8	3663.6	3829.7	4057.1	4301.0
Real	1566.3	1512.0	1548.8	1522.1	1478.7	1456.5	1455.8	1461.4	1488.5	1496.6	1526.4	1537.8	1552.7	1545.1	1571.7	1601.3	1652.9	1644.1	1657.2	1671.6
NPV (9.54% discount rate)	21342.8																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.1	2178.4	2292.8	2403.3	2564.0	2779.5	3019.2	3328.6	3614.8	3975.6	4325.9	4711.5	5050.9	5517.9	6018.7	6624.4	7047.7	7604.0	8208.6
Real	1912.2	1891.7	1972.1	1975.0	1969.6	1999.4	2062.3	2131.5	2235.9	2310.3	2417.6	2502.9	2593.7	2645.6	2750.0	2854.1	2988.9	3025.5	3105.9	3190.2
NPV (9.54% discount rate)	32336.1																			
Average Growth																				
Nominal	7.97%																			
Real	2.73%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.2	51.7	54.5	57.5	61.2	64.1	68.5	72.2	76.3	79.3	84.6	89.6	96.1	99.6	105.3	111.0
Real	45.9	43.4	43.9	42.6	41.1	40.3	40.5	40.6	41.1	41.0	41.6	41.8	42.0	41.5	42.2	42.5	43.4	42.7	43.0	43.1
Average Growth																				
Nominal	4.76%																			
Real	-0.33%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium-High Step 4

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Medium CT (Jul) (0)					10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CT (0)								20	20	20	20	20	20	20	20	20	20	20	20	20
Medium CT (1)								20	20	20	20	20	20	20	20	20	20	20	20	20
Medium CT (2)									20	20	20	20	20	20	20	20	20	20	20	20
Large CC CT (2)										175	175	175	175	175	175	175	175	175	175	175
Large CC CT (3)											175	175	175	175	175	175	175	175	175	175
Hunter 4 (1)																300	300	300	300	300
Large CC CT (4)												175	175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Large CC CT																				175
Large CC CT (Jul)																				88
total	6,697	6,784	7,021	7,211	7,356	7,565	7,836	7,917	8,132	8,381	8,662	8,817	8,919	9,075	9,298	9,586	9,647	9,785	9,963	10,183
Balance	180	179	229	229	148	163	241	144	143	184	235	183	162	175	192	346	198	173	147	147

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4/1 RIM - Medium High Forecast
Medium-High Step 4

Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (Jul) (0)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (0)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (2)									100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)											250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)																400	400	400	400	400
Large CC CT (4)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT (Jul)																				
total	9,479	9,865	10,167	10,577	10,757	11,097	11,946	12,313	12,553	12,955	13,317	13,650	13,697	14,029	14,211	14,671	14,669	14,960	15,083	15,389
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,556	1,604	1,644	1,681	1,681	1,719	1,836	1,896	1,896	1,933	1,971	2,029
Balance	-153	13	77	206	184	217	738	756	716	763	780	767	722	830	589	897	617	597	473	429
(Reserve+Balance)/Requirement	14%	15%	16%	17%	17%	17%	23%	23%	22%	22%	22%	22%	21%	22%	21%	24%	21%	20%	19%	19%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium-High Step 4

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Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (Jul) (0)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (0)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (2)									100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)											250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)																400	400	400	400	400
Large CC CT (4)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT (Jul)																				250
total	9,783	9,833	10,154	10,495	10,682	10,896	11,267	11,579	11,830	12,211	12,553	12,838	12,911	13,232	13,418	13,908	13,947	14,231	14,363	14,896
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,556	1,604	1,644	1,681	1,681	1,719	1,836	1,896	1,896	1,933	1,971	2,029
Balance	81	93	176	246	48	-1	51	139	55	183	189	141	130	246	6	351	120	176	29	220
(Reserve+Balance)/Requirement	16%	17%	17%	18%	15%	15%	16%	17%	16%	17%	17%	17%	16%	17%	16%	19%	17%	17%	16%	18%

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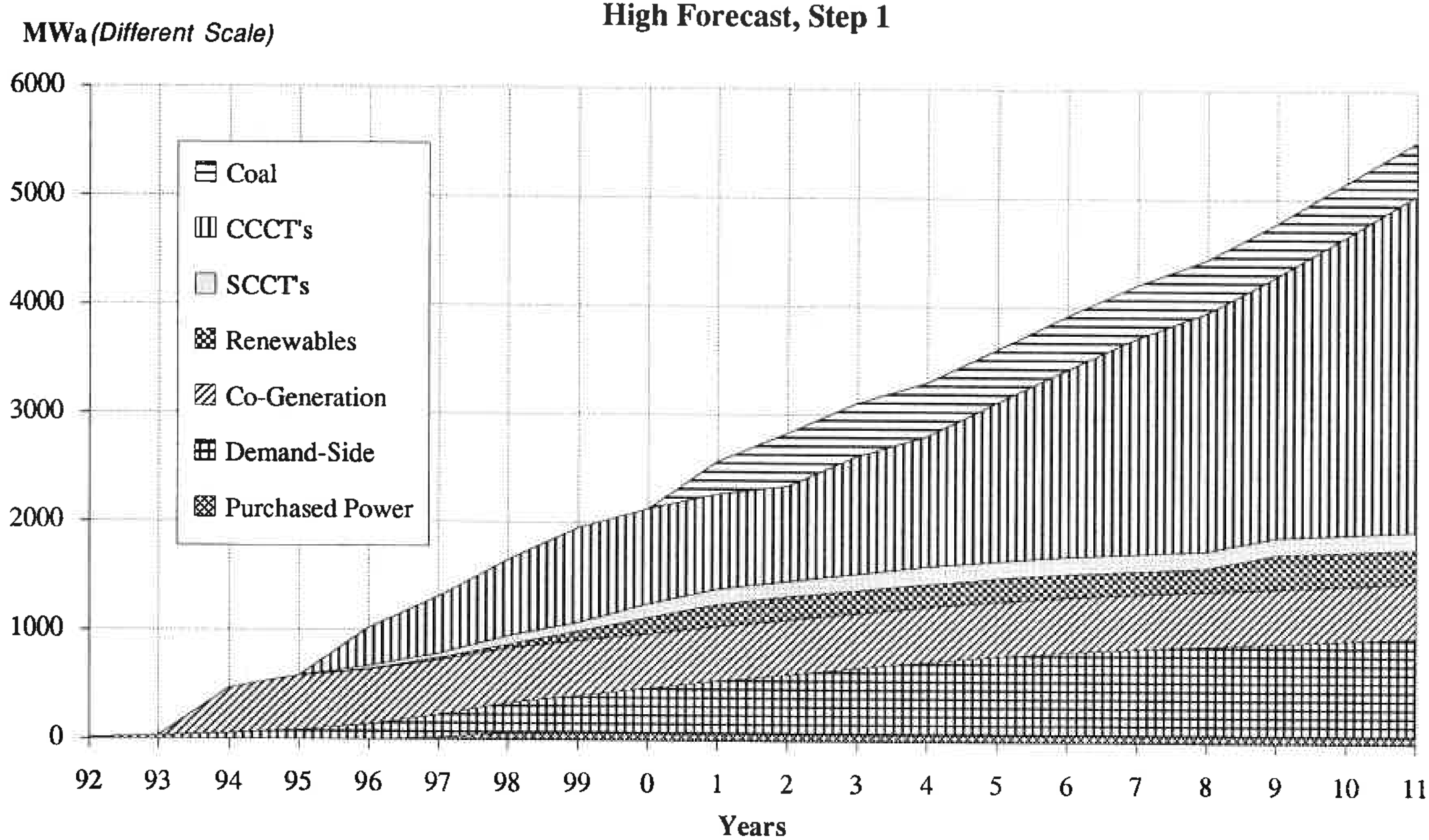
PacifiCorp - RAMPP 2

Illustrative Plan
High Forecast, Step 1



KEY OUTPUTS

High Step 1

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5550.0	5873.0	6125.0	6386.0	6674.0	6948.0	7229.0	7557.0	7885.0	8216.0	8545.0	8877.0	9199.0	9517.0	9859.0	10182.0	10496.0	10808.0	11129.0
Total Conservation	4.5	15.5	30.9	54.0	88.0	139.7	203.6	275.7	348.2	418.6	485.1	548.5	610.0	670.5	722.5	766.5	796.8	825.9	853.9	881.9
System Load net of Conservation	5195.5	5534.5	5842.1	6071.0	6298.0	6534.3	6744.4	6953.4	7208.8	7466.4	7731.0	7996.5	8267.0	8528.5	8794.5	9092.5	9385.2	9670.1	9954.1	10247.1
Energy Sales after Conservation	4749.7	5059.6	5340.9	5550.1	5757.6	5973.7	6165.8	6356.8	6590.3	6825.8	7067.6	7310.4	7557.7	7796.8	8039.9	8312.4	8579.9	8840.4	9100.0	9367.9
Total Customers (000's)	1,230	1,267	1,294	1,323	1,361	1,405	1,449	1,490	1,535	1,578	1,621	1,668	1,715	1,759	1,802	1,843	1,885	1,929	1,976	2,025
Net Electric Plant (M$)	5945.7	6544.0	6988.5	7533.0	8145.0	8858.9	9891.2	11089.5	12361.0	13501.9	14441.1	15234.4	16040.6	16919.3	17760.1	18625.8	19802.1	21000.9	21694.3	22023.5
Net Conservation Assets	16.1	57.5	119.6	208.6	335.3	504.7	794.1	1117.2	1442.1	1748.6	2025.5	2280.4	2520.9	2748.8	2911.2	3012.7	3012.4	3000.6	2980.9	2963.5
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.9	2001.8	2214.8	2366.0	2507.1	2784.0	3040.6	3339.3	3703.2	4070.1	4558.0	5013.0	5520.2	5984.6	6545.3	7226.4	7936.1	8663.5	9508.4	10419.0
Real	1910.9	1904.6	2005.1	2038.0	2054.8	2171.0	2256.0	2357.4	2487.5	2601.3	2771.7	2900.5	3039.0	3134.7	3262.1	3426.7	3580.7	3719.2	3883.8	4049.3
NPV (9.54% discount rate)	36393.4																			
Average Growth																				
Nominal	9.34%																			
Real	4.03%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.0	47.3	48.7	49.7	53.1	56.3	60.0	64.1	67.9	73.6	78.3	83.4	87.4	92.9	99.2	105.6	111.6	119.3	127.0
Real	45.9	42.9	42.9	41.9	40.7	41.4	41.8	42.3	43.1	43.4	44.8	45.3	45.9	45.8	46.3	47.1	47.6	47.9	48.7	49.3
Average Growth																				
Nominal	5.50%																			
Real	0.38%																			
Average Customer Bill ($)																				
Nominal	1553.5	1580.4	1711.1	1788.1	1842.0	1981.6	2098.5	2240.5	2412.4	2579.2	2811.4	3005.2	3219.3	3401.6	3631.8	3920.3	4210.9	4492.2	4811.2	5146.1
Real	1553.5	1503.7	1549.1	1540.2	1509.7	1545.2	1557.0	1581.7	1620.4	1648.4	1709.6	1738.8	1772.3	1781.8	1810.0	1859.0	1899.9	1928.5	1965.2	2000.0
NPV (9.54% discount rate)	23161.5																			
Customer Cost (M$)	2.8	3.6	3.6	3.9	5.0	0.0	-3.9	-4.8	-3.0	-1.0	4.3	9.6	14.8	18.0	33.4	47.5	75.2	103.8	133.2	167.5
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.7	1.0	1.4	1.9	1.9	1.5	1.0	0.7	0.6	1.1	2.1	3.6	5.4	8.8	13.7	21.3	31.9	45.5	62.6
NPV (9.54% discount rate)	49.1																			
Energy Services Charge (M$)	1.0	4.2	9.2	16.6	27.0	41.1	66.7	96.0	126.8	158.9	191.7	226.2	262.4	300.6	335.0	365.0	371.8	376.6	378.8	378.7
NPV (9.54% discount rate)	1124.1																			
Total Resource Cost (M$)																				
Nominal	1912.3	2006.6	2225.0	2384.1	2536.0	2827.1	3108.8	3436.3	3830.8	4229.7	4750.8	5241.3	5786.2	6290.6	6889.1	7605.1	8329.2	9072.0	9932.7	10860.4
Real	1912.3	1909.2	2014.3	2053.6	2078.5	2204.6	2306.6	2425.9	2573.2	2703.2	2889.0	3032.6	3185.4	3295.0	3433.4	3606.3	3758.0	3894.5	4057.1	4220.8
NPV (9.54% discount rate)	37566.6																			
Average Growth																				
Nominal	9.57%																			
Real	4.26%																			
Mills / KWh																				
Nominal	45.9	45.0	47.3	48.6	49.6	52.7	55.9	59.4	63.3	66.8	72.2	76.6	81.4	85.2	90.4	96.3	102.1	107.6	114.8	121.9
Real	45.9	42.8	42.8	41.9	40.6	41.1	41.5	41.9	42.5	42.7	43.9	44.3	44.8	44.6	45.0	45.7	46.1	46.2	46.9	47.4
Average Growth																				
Nominal	5.27%																			
Real	0.16%																			

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,550	5,873	6,125	6,386	6,674	6,948	7,229	7,557	7,885	8,216	8,545	8,877	9,199	9,517	9,859	10,182	10,496	10,808	11,129	11,460
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,644	6,868	7,125	7,390	7,702	7,984	8,267	8,542	8,856	9,162	9,491	9,800	10,025	10,271	10,581	10,817	11,131	11,399	11,712	12,042
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	4	8	14	24	37	50	62	76	89	103	116	130	142	155	167	178	190	201	213	225
D.S. Options (1)	12	23	40	64	103	154	213	272	329	382	432	480	528	568	600	619	636	653	669	685
CoGen 1 (1)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen (1)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (3)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen 1 (4)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CC CT (1)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CC CT (2)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)					31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (3)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Small CT (Jul) (1)						4	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)						4	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Hunter 4 (1)										300	300	300	300	300	300	300	300	300	300	300
Large CC CT (4)							175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Wyodak 2 (1)											192	192	192	192	192	192	192	192	192	192
Large CC CT (5)								175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (Jul) (1)									16	31	31	31	31	31	31	31	31	31	31	31
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (6)												175	175	175	175	175	175	175	175	175
Medium CC CT (Jul) (1)												32	64	64	64	64	64	64	64	64
Small CT (Jul) (3)												4	8	8	8	8	8	8	8	8
Small CT (Jul) (4)												4	8	8	8	8	8	8	8	8
Large CC CT (Jul)													88	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT (Jul)															88	175	175	175	175	175
Large CC CT																175	175	175	175	175
Large CC CT																	175	175	175	175
Medium CC CT (Jul)																	32	64	64	64
Large CC CT																		175	175	175
New Geothermal																		100	100	100
Large CC CT																			175	175
Large CC CT																			175	175
Large CC CT																				175
Large CC CT																				175
total	6,699	6,788	7,445	7,564	7,917	8,134	8,566	8,792	9,043	9,441	9,748	9,954	10,193	10,440	10,759	11,013	11,286	11,559	11,916	12,227
Balance	55	-80	319	174	215	150	299	249	187	279	257	154	168	169	178	196	155	159	204	185

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,312	7,651	7,985	8,334	8,722	9,091	9,467	9,908	10,348	10,791	11,232	11,677	12,107	12,534	12,989	13,419	13,838	14,254	14,685	15,120
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,589	8,904	9,238	9,591	9,881	10,250	10,626	11,067	11,457	11,900	12,341	12,786	13,016	13,343	13,790	14,020	14,439	14,855	15,211	15,646
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	5	11	20	34	52	70	88	108	128	148	168	188	208	227	246	265	284	303	323	342
D.S. Options (1)	15	30	55	90	156	244	347	448	546	636	719	799	878	944	998	1,029	1,058	1,085	1,112	1,138
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (3)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen 1 (4)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Small CT (Jul) (1)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Hunter 4 (1)										400	400	400	400	400	400	400	400	400	400	400
Large CC CT (4)							250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)											256	256	256	256	256	256	256	256	256	256
Large CC CT (5)								250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (Jul) (1)										156	156	156	156	156	156	156	156	156	156	156
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (6)												250	250	250	250	250	250	250	250	250
Medium CC CT (Jul) (1)													128	128	128	128	128	128	128	128
Small CT (Jul) (3)													40	40	40	40	40	40	40	40
Small CT (Jul) (4)													40	40	40	40	40	40	40	40
Large CC CT (Jul)														250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Medium CC CT (Jul)																		128	128	128
Large CC CT																		250	250	250
New Geothermal																		100	100	100
Large CC CT																			250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT																				250
total	9,482	9,872	10,668	10,997	11,645	11,900	12,938	13,371	13,681	14,405	14,789	15,136	15,407	15,997	16,191	16,759	17,013	17,538	17,918	18,482
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,373	1,388	1,487	1,527	1,628	1,673	1,706	1,799	1,840	1,877	1,909	1,984	2,021	2,096	2,134	2,205	2,280	2,355
Balance	-407	-332	57	17	277	124	685	631	518	706	608	473	482	671	380	642	440	478	427	481
(Reserve+Balance)/Requirement	10%	11%	15%	15%	18%	16%	22%	21%	19%	21%	20%	18%	18%	20%	17%	20%	18%	18%	18%	18%

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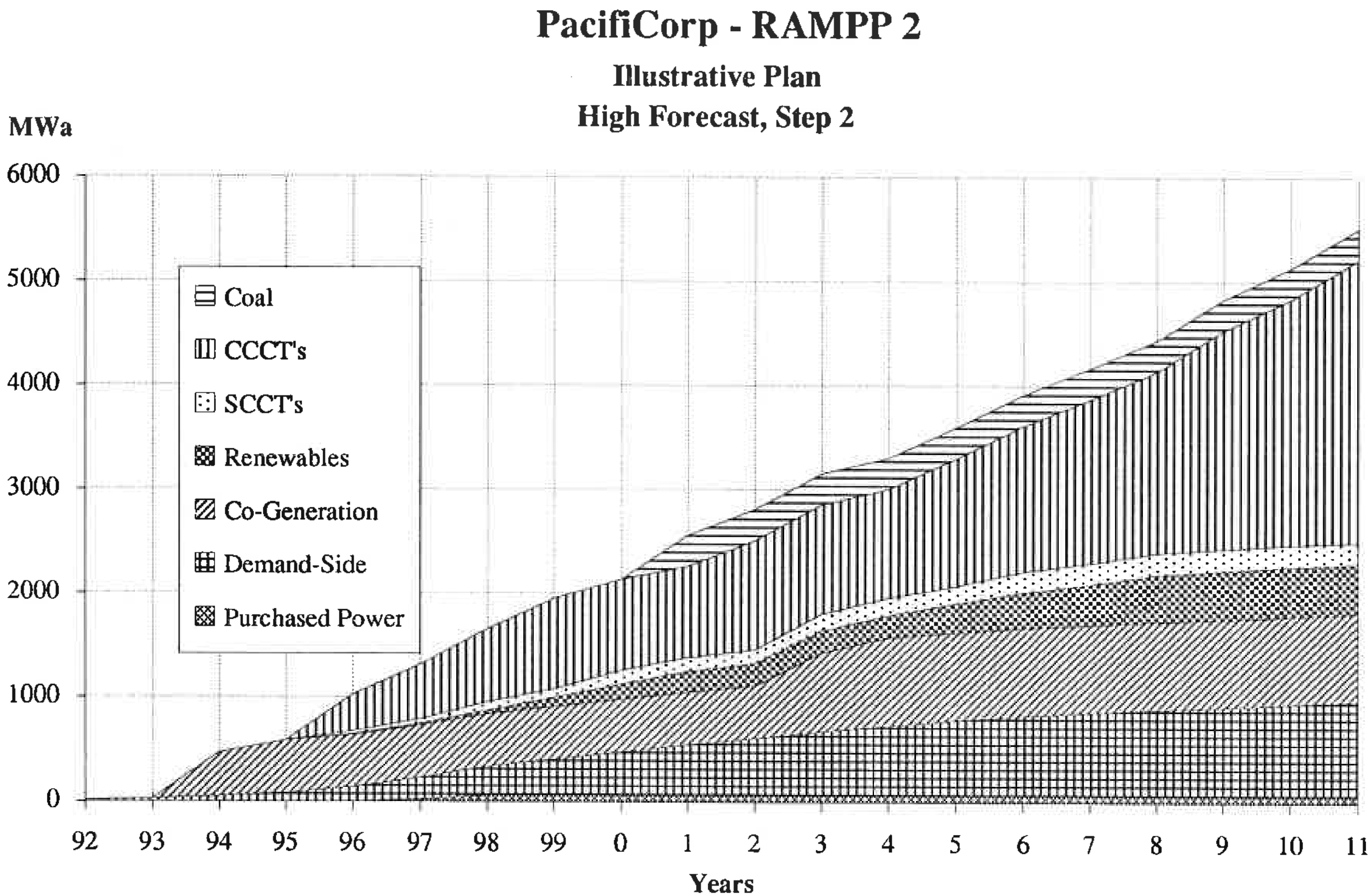
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,837	7,166	7,489	7,826	8,195	8,545	8,903	9,346	9,767	10,190	10,611	11,034	11,446	11,852	12,292	12,707	13,110	13,509	13,897	14,315
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,650	8,779	9,106	9,445	9,909	10,224	10,582	10,885	11,321	11,649	12,070	12,493	12,705	13,003	13,443	13,658	14,061	14,385	14,773	15,191
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	14	24	36	48	60	73	86	99	112	125	138	150	163	175	187	200	212	224
D.S. Options (1)	12	24	43	72	128	202	290	375	459	538	614	688	762	824	875	903	930	956	981	1,006
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (3)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen 1 (4)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Hunter 4 (1)										400	400	400	400	400	400	400	400	400	400	400
Large CC CT (4)							250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)											256	256	256	256	256	256	256	256	256	256
Large CC CT (5)								250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (Jul) (1)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (6)												250	250	250	250	250	250	250	250	250
Medium CC CT (Jul) (1)												128	128	128	128	128	128	128	128	128
Small CT (Jul) (3)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (4)												40	40	40	40	40	40	40	40	40
Large CC CT (Jul)													250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Medium CC CT (Jul)																	128	128	128	128
Large CC CT																		250	250	250
New Geothermal																		100	100	100
Large CC CT																			250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT																				250
total	9,786	9,838	10,652	10,911	11,465	11,772	12,251	12,627	13,105	13,650	14,012	14,519	14,857	15,186	15,633	15,979	16,402	16,791	17,179	17,718
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,373	1,388	1,487	1,527	1,628	1,673	1,706	1,799	1,840	1,877	1,909	1,984	2,021	2,096	2,134	2,205	2,280	2,355
Balance	-164	-241	173	78	69	22	42	70	78	201	102	149	243	200	169	225	207	201	125	172
(Reserve+Balance)/Requirement	13%	12%	17%	16%	16%	15%	16%	16%	16%	17%	16%	16%	17%	17%	16%	17%	17%	17%	16%	17%


PacifiCorp - RAMPP 2
Illustrative Plan
High Forecast, Step 2
MWa
6000
5000
4000
3000
2000
1000
0
Coal
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS
High, Step 2

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5550.0	5873.0	6125.0	6386.0	6674.0	6948.0	7229.0	7557.0	7885.0	8216.0	8545.0	8877.0	9199.0	9517.0	9859.0	10182.0	10496.0	10808.0	11129.0
Total Conservation	4.5	15.5	30.9	54.0	88.0	139.7	203.6	275.7	348.2	418.6	485.1	548.5	610.0	670.5	722.5	766.5	796.8	825.9	853.9	881.9
System Load net of Conservation	5195.5	5534.5	5842.1	6071.0	6298.0	6534.3	6744.4	6953.4	7208.8	7466.4	7731.0	7996.5	8267.0	8528.5	8794.5	9092.5	9385.2	9670.1	9954.1	10247.1
Energy Sales after Conservation	4749.7	5059.6	5340.9	5550.1	5757.6	5973.7	6165.8	6356.8	6590.3	6825.8	7067.6	7310.4	7557.7	7796.8	8039.9	8312.4	8579.9	8840.4	9100.0	9367.9
Total Customers (000's)	1,230	1,267	1,294	1,323	1,361	1,405	1,449	1,490	1,535	1,578	1,621	1,668	1,715	1,759	1,802	1,843	1,885	1,929	1,976	2,025
Net Electric Plant (M$)	5945.7	6544.0	6988.5	7533.0	8145.0	8858.9	9835.6	10872.8	11959.7	12810.1	13393.0	13968.8	14774.4	15901.1	17026.1	18098.6	19250.3	20329.0	21113.6	21450.6
Net Conservation Assets	16.1	57.5	119.6	208.6	335.3	504.7	794.1	1117.2	1442.1	1748.6	2025.5	2280.4	2520.9	2748.8	2911.2	3012.7	3012.4	3000.6	2980.9	2963.5
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.9	2001.8	2214.8	2366.0	2507.1	2784.0	3039.9	3336.6	3698.2	4053.9	4536.5	4945.6	5397.8	5818.5	6440.9	7151.0	7888.7	8628.1	9478.3	10403.2
Real	1910.9	1904.6	2005.1	2038.0	2054.8	2171.0	2255.5	2355.5	2484.1	2590.9	2758.6	2861.5	2971.5	3047.7	3210.0	3391.0	3559.3	3704.0	3871.5	4043.1
NPV (9.54% discount rate)	36181.3																			
Average Growth																				
Nominal	9.33%																			
Real	4.02%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.0	47.3	48.7	49.7	53.1	56.3	59.9	64.1	67.6	73.3	77.2	81.5	85.0	91.5	98.2	105.0	111.1	118.9	126.8
Real	45.9	42.9	42.9	41.9	40.7	41.4	41.8	42.3	43.0	43.2	44.6	44.7	44.9	44.5	45.6	46.6	47.4	47.7	48.6	49.3
Average Growth																				
Nominal	5.49%																			
Real	0.37%																			
Average Customer Bill ($)																				
Nominal	1553.5	1580.4	1711.1	1788.1	1842.0	1981.6	2098.0	2238.7	2409.1	2569.0	2798.1	2964.8	3147.9	3307.2	3573.9	3879.4	4185.8	4473.9	4796.0	5138.3
Real	1553.5	1503.7	1549.1	1540.2	1509.7	1545.2	1556.7	1580.4	1618.2	1641.9	1701.5	1715.4	1732.9	1732.3	1781.1	1839.6	1888.6	1920.6	1959.0	1997.0
NPV (9.54% discount rate)	23040.5																			
Customer Cost (M$)	2.8	3.6	3.6	3.9	5.0	0.0	-3.9	-4.8	-3.0	-1.0	4.3	9.6	14.8	18.0	33.4	47.5	75.2	103.8	133.2	167.5
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.7	1.0	1.4	1.9	1.9	1.5	1.0	0.7	0.6	1.1	2.1	3.6	5.4	8.8	13.7	21.3	31.9	45.5	62.6
NPV (9.54% discount rate)	49.1																			
Energy Services Charge (M$)	1.0	4.2	9.2	16.6	27.0	41.1	66.7	96.0	126.8	158.9	191.7	226.2	262.4	300.6	335.0	365.0	371.8	376.6	378.8	378.7
NPV (9.54% discount rate)	1124.1																			
Total Resource Cost (M$)																				
Nominal	1912.3	2006.6	2225.0	2384.1	2536.0	2827.1	3108.1	3433.6	3825.8	4213.5	4729.3	5173.9	5663.8	6124.4	6784.7	7529.7	8281.8	9036.6	9902.6	10844.6
Real	1912.3	1909.2	2014.3	2053.6	2078.5	2204.6	2306.1	2424.0	2569.8	2692.9	2875.9	2993.6	3118.0	3208.0	3381.4	3570.6	3736.6	3879.3	4044.8	4214.6
NPV (9.54% discount rate)	37354.5																			
Average Growth																				
Nominal	9.56%																			
Real	4.25%																			
Mills / KWh																				
Nominal	45.9	45.0	47.3	48.6	49.6	52.7	55.9	59.3	63.2	66.5	71.9	75.6	79.7	82.9	89.0	95.4	101.6	107.2	114.4	121.7
Real	45.9	42.8	42.8	41.9	40.6	41.1	41.4	41.9	42.5	42.5	43.7	43.7	43.9	43.4	44.4	45.2	45.8	46.0	46.7	47.3
Average Growth																				
Nominal	5.26%																			
Real	0.15%																			

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,550	5,873	6,125	6,386	6,674	6,948	7,229	7,557	7,885	8,216	8,545	8,877	9,199	9,517	9,859	10,182	10,496	10,808	11,129	11,460
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,644	6,868	7,125	7,390	7,702	7,984	8,267	8,542	8,856	9,162	9,491	9,800	10,025	10,271	10,581	10,817	11,131	11,399	11,712	12,042
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	4	8	14	24	37	50	62	76	89	103	116	130	142	155	167	178	190	201	213	225
D.S. Options (1)	12	23	40	64	103	154	213	272	329	382	432	480	528	568	600	619	636	653	669	685
CoGen 1 (1)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen (1)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (3)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen 1 (4)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CC CT (1)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CC CT (2)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)					31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (3)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Small CT (Jul) (1)						4	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)						4	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Hunter 4 (1)										300	300	300	300	300	300	300	300	300	300	300
Large CC CT (4)							175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (5)								175	175	175	175	175	175	175	175	175	175	175	175	175
Medium CT (1)									20	20	20	20	20	20	20	20	20	20	20	20
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
More Geothermal (1)														45	45	45	45	45	45	45
Large CC CT (6)											175	175	175	175	175	175	175	175	175	175
More Geothermal (2)															45	45	45	45	45	45
More CoGen 1 (1)												85	85	85	85	85	85	85	85	85
More CoGen 1 (2)												85	85	85	85	85	85	85	85	85
More CoGen 1 (3)												85	85	85	85	85	85	85	85	85
Large CT (4)												31	31	31	31	31	31	31	31	31
More Wind (1)													5	22	38	42	58	73	83	83
More Geothermal (3)																45	45	45	45	45
More CoGen 1													85	85	85	85	85	85	85	85
Large CC CT														175	175	175	175	175	175	175
Small CT (Jul)														4	8	8	8	8	8	8
Large CC CT															175	175	175	175	175	175
Large CT															31	31	31	31	31	31
Large CC CT																175	175	175	175	175
More Geothermal																	45	45	45	45
Large CC CT																	175	175	175	175
Small CT																	8	8	8	8
Large CC CT																		175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Large CC CT (Jul)																			88	175
Large CC CT																				175
Large CC CT (Jul)																				88
total	6,699	6,788	7,445	7,564	7,917	8,134	8,566	8,792	9,047	9,430	9,720	9,996	10,197	10,424	10,751	10,968	11,276	11,607	11,889	12,200
Balance	55	-80	319	174	215	150	299	249	191	267	229	196	172	153	169	151	145	208	177	157

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,312	7,651	7,985	8,334	8,722	9,091	9,467	9,908	10,348	10,791	11,232	11,677	12,107	12,534	12,989	13,419	13,838	14,254	14,685	15,120
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,589	8,904	9,238	9,591	9,881	10,250	10,626	11,067	11,457	11,900	12,341	12,786	13,016	13,343	13,790	14,020	14,439	14,855	15,211	15,646
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	5	11	20	34	52	70	88	108	128	148	168	188	208	227	246	265	284	303	323	342
D.S. Options (1)	15	30	55	90	156	244	347	448	546	636	719	799	878	944	998	1,029	1,058	1,085	1,112	1,138
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (3)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen 1 (4)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Small CT (Jul) (1)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Hunter 4 (1)										400	400	400	400	400	400	400	400	400	400	400
Large CC CT (4)							250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (5)								250	250	250	250	250	250	250	250	250	250	250	250	250
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
More Geothermal (1)														50	50	50	50	50	50	50
Large CC CT (6)											250	250	250	250	250	250	250	250	250	250
More Geothermal (2)															50	50	50	50	50	50
More CoGen 1 (1)												100	100	100	100	100	100	100	100	100
More CoGen 1 (2)												100	100	100	100	100	100	100	100	100
More CoGen 1 (3)												100	100	100	100	100	100	100	100	100
Large CT (4)												156	156	156	156	156	156	156	156	156
More Wind (1)														16	39	39	55	71	87	87
More Geothermal (3)																50	50	50	50	50
More CoGen 1													100	100	100	100	100	100	100	100
Large CC CT														250	250	250	250	250	250	250
Small CT (Jul)															40	40	40	40	40	40
Large CC CT															250	250	250	250	250	250
Large CT															156	156	156	156	156	156
Large CC CT																250	250	250	250	250
More Geothermal																	50	50	50	50
Large CC CT																	250	250	250	250
Small CT																	40	40	40	40
Large CC CT																		250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT (Jul)																				250
Large CC CT																				250
Large CC CT (Jul)																				
total	9,482	9,872	10,668	10,997	11,645	11,900	12,938	13,371	13,781	14,349	14,727	15,280	15,443	15,849	16,313	16,680	17,040	17,603	17,749	18,313
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,373	1,388	1,487	1,527	1,628	1,673	1,721	1,791	1,831	1,899	1,914	1,961	2,039	2,084	2,144	2,221	2,261	2,336
Balance	-407	-332	57	17	277	124	685	631	603	658	555	596	513	545	483	576	457	527	277	331
(Reserve+Balance)/Requirement	10%	11%	15%	15%	18%	16%	22%	21%	20%	21%	19%	20%	19%	19%	18%	19%	18%	18%	17%	17%

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High, Step 2

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,837	7,166	7,489	7,826	8,195	8,545	8,903	9,346	9,767	10,190	10,611	11,034	11,446	11,852	12,292	12,707	13,110	13,509	13,897	14,315
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,650	8,779	9,106	9,445	9,909	10,224	10,582	10,885	11,321	11,649	12,070	12,493	12,705	13,003	13,443	13,658	14,061	14,385	14,773	15,191
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	14	24	36	48	60	73	86	99	112	125	138	150	163	175	187	200	212	224
D.S. Options (1)	12	24	43	72	128	202	290	375	459	538	614	688	762	824	875	903	930	956	981	1,006
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (3)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen 1 (4)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Hunter 4 (1)										400	400	400	400	400	400	400	400	400	400	400
Large CC CT (4)							250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (5)								250	250	250	250	250	250	250	250	250	250	250	250	250
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
More Geothermal (1)														50	50	50	50	50	50	50
Large CC CT (6)											250	250	250	250	250	250	250	250	250	250
More Geothermal (2)															50	50	50	50	50	50
More CoGen 1 (1)												100	100	100	100	100	100	100	100	100
More CoGen 1 (2)												100	100	100	100	100	100	100	100	100
More CoGen 1 (3)												100	100	100	100	100	100	100	100	100
Large CT (4)												156	156	156	156	156	156	156	156	156
More Wind (1)														10	25	25	35	45	55	55
More Geothermal (3)																50	50	50	50	50
More CoGen 1													100	100	100	100	100	100	100	100
Large CC CT														250	250	250	250	250	250	250
Small CT (Jul)														40	40	40	40	40	40	40
Large CC CT															250	250	250	250	250	250
Large CT															156	156	156	156	156	156
Large CC CT																250	250	250	250	250
More Geothermal																	50	50	50	50
Large CC CT																	250	250	250	250
Small CT																	40	40	40	40
Large CC CT																		250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT (Jul)																			250	250
Large CC CT																				250
Large CC CT (Jul)																				250
total	9,786	9,838	10,652	10,911	11,465	11,772	12,251	12,627	13,049	13,594	13,950	14,455	14,643	15,072	15,490	15,886	16,281	16,830	17,228	17,767
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,373	1,388	1,487	1,527	1,628	1,673	1,721	1,791	1,831	1,899	1,914	1,961	2,039	2,084	2,144	2,221	2,261	2,336
Balance	-164	-241	173	78	69	22	42	70	7	154	49	63	24	108	8	144	76	224	194	240
(Reserve+Balance)/Requirement	13%	12%	17%	16%	16%	15%	16%	16%	15%	17%	16%	16%	15%	16%	15%	16%	16%	17%	17%	17%

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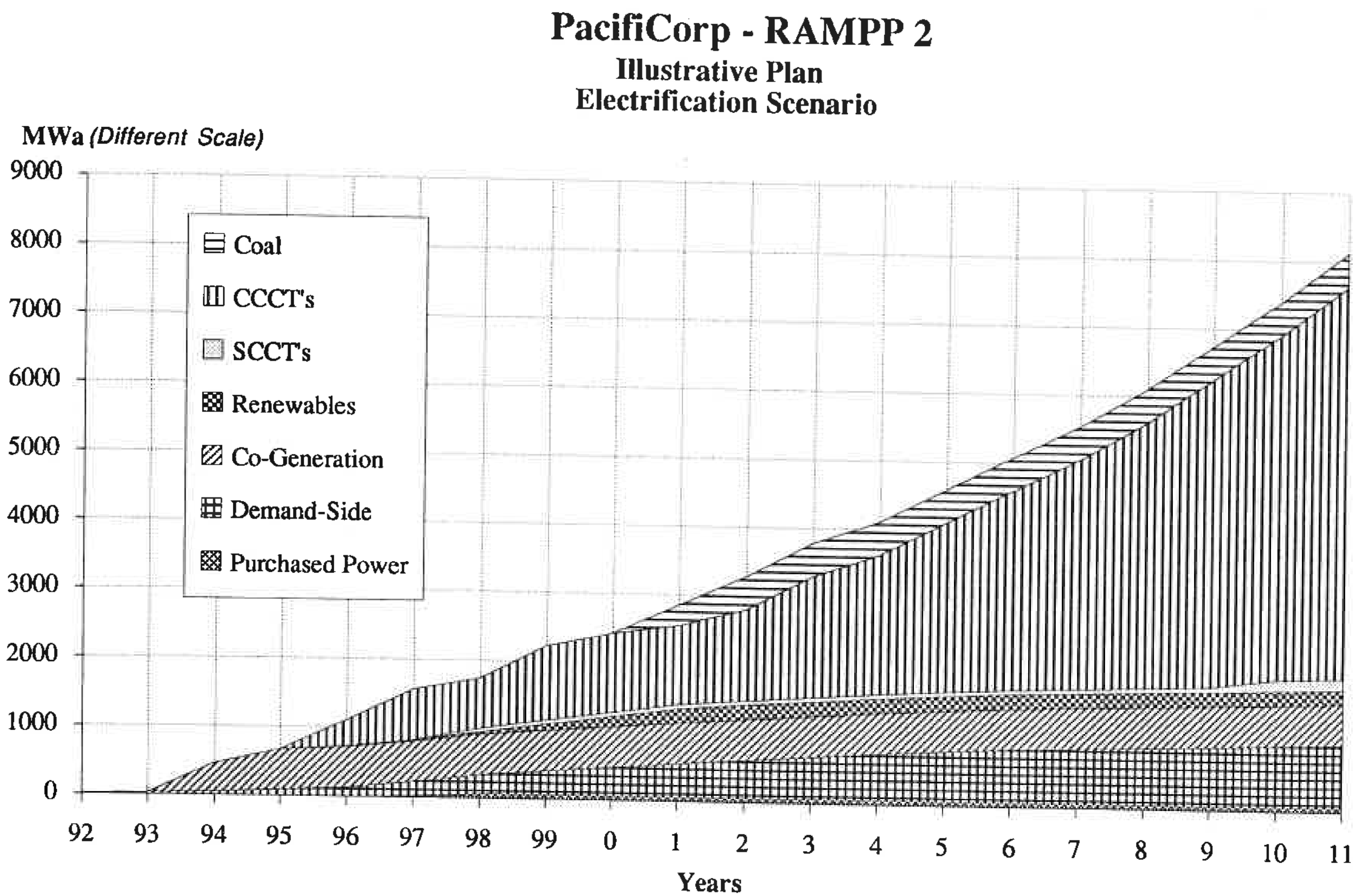

PacifiCorp - RAMPP 2
Illustrative Plan
Electrification Scenario
MWa (Different Scale)
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Coal
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

Electrification Scenario

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5550.0	5873.0	6125.0	6431.3	6752.8	7090.5	7445.0	7817.2	8208.1	8618.5	9049.4	9501.9	9977.0	10475.8	10999.6	11549.6	12127.1	12733.4	13370.1
Total Conservation	4.5	15.5	30.9	54.0	88.0	139.7	203.6	275.7	348.2	418.6	485.1	548.5	610.0	670.5	722.5	766.5	796.8	825.9	853.9	881.9
System Load net of Conservation	5195.5	5534.5	5842.1	6071.0	6343.3	6613.1	6886.9	7169.3	7469.1	7789.5	8133.4	8501.0	8891.9	9306.5	9753.3	10233.2	10752.8	11301.1	11879.5	12488.2
Energy Sales after Conservation	4749.7	5059.6	5340.9	5550.1	5799.0	6045.7	6296.0	6554.2	6828.2	7121.1	7435.6	7771.6	8129.0	8508.0	8916.5	9355.2	9830.2	10331.5	10860.3	11416.7
Total Customers (000's)	1,230	1,267	1,294	1,323	1,361	1,405	1,449	1,490	1,535	1,578	1,621	1,668	1,715	1,759	1,802	1,843	1,885	1,929	1,976	2,025
Net Electric Plant (M$)	5945.7	6544.0	7009.6	7602.3	8233.8	9039.6	10205.7	11440.7	12778.5	14167.3	15365.1	16432.4	17566.1	18876.3	20274.9	21895.0	23697.9	25717.4	27117.6	27503.7
Net Conservation Assets	16.1	57.5	119.6	208.6	335.3	504.7	794.1	1117.2	1442.1	1748.6	2025.5	2280.4	2520.9	2748.8	2911.2	3012.7	3012.4	3000.6	2980.9	2963.5
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1936.9	2015.0	2215.3	2367.0	2533.1	2825.3	3144.2	3451.4	3895.6	4291.9	4833.8	5423.1	6091.9	6694.4	7554.7	8434.7	9546.2	10700.0	12085.6	13731.9
Real	1936.9	1917.2	2005.5	2038.9	2076.0	2203.2	2332.9	2436.5	2616.7	2743.0	2939.4	3137.7	3353.7	3506.5	3765.1	3999.7	4307.1	4593.5	4936.5	5336.8
NPV (9.54% discount rate)	39940.2																			
Average Growth																				
Nominal	10.86%																			
Real	5.48%																			
Base Unit Cost (mills/kwh)																				
Nominal	46.6	45.3	47.3	48.7	49.9	53.2	57.0	60.1	65.1	68.6	74.2	79.7	85.5	89.6	96.7	102.9	110.9	117.9	127.0	137.3
Real	46.6	43.1	42.9	41.9	40.9	41.5	42.3	42.4	43.7	43.9	45.1	46.1	47.1	46.9	48.2	48.8	50.0	50.6	51.9	53.4
Average Growth																				
Nominal	5.86%																			
Real	0.72%																			
Average Customer Bill ($)																				
Nominal	1574.6	1590.8	1711.5	1788.8	1861.1	2011.0	2170.0	2315.6	2537.7	2719.8	2981.5	3251.0	3552.7	3805.1	4191.9	4575.9	5065.3	5548.2	6115.2	6782.4
Real	1574.6	1513.6	1549.5	1540.9	1525.3	1568.2	1610.1	1634.7	1704.6	1738.2	1813.0	1881.0	1955.8	1993.1	2089.1	2169.9	2285.4	2381.8	2497.8	2635.9
NPV (9.54% discount rate)	25111.4																			
Customer Cost (M$)	2.8	3.6	3.6	3.9	5.0	0.0	-3.9	-4.8	-3.0	-1.0	4.3	9.6	14.8	18.0	33.4	47.5	75.2	103.8	133.2	167.5
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.7	1.0	1.4	1.9	1.9	1.5	1.0	0.7	0.6	1.1	2.1	3.6	5.4	8.8	13.7	21.3	31.9	45.5	62.6
NPV (9.54% discount rate)	49.1																			
Energy Services Charge (M$)	1.0	4.2	9.2	16.6	27.0	41.1	66.7	96.0	126.8	158.9	191.7	226.2	262.4	300.6	335.0	365.0	371.8	376.6	378.8	378.7
NPV (9.54% discount rate)	1124.1																			
Total Resource Cost (M$)																				
Nominal	1938.3	2019.8	2225.5	2385.1	2562.0	2868.4	3212.4	3548.4	4023.1	4451.4	5026.6	5651.4	6357.9	7000.4	7898.4	8813.4	9939.2	11108.5	12509.8	14173.3
Real	1938.3	1921.8	2014.8	2054.4	2099.7	2236.8	2383.5	2505.0	2702.4	2844.9	3056.7	3269.8	3500.1	3666.8	3936.4	4179.3	4484.5	4768.8	5109.8	5508.3
NPV (9.54% discount rate)	41113.5																			
Average Growth																				
Nominal	11.04%																			
Real	5.65%																			
Mills / KWh																				
Nominal	46.5	45.3	47.3	48.6	49.7	52.9	56.6	59.5	64.3	67.5	72.8	78.0	83.6	87.4	94.1	100.1	107.5	114.1	122.7	132.4
Real	46.5	43.1	42.8	41.9	40.8	41.2	42.0	42.0	43.2	43.2	44.3	45.1	46.0	45.8	46.9	47.4	48.5	49.0	50.1	51.4
Average Growth																				
Nominal	5.66%																			
Real	0.53%																			

PacifiCorp Electric Operations
4/1 RIM - Super High Forecast
Electrification Scenario

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,550	5,873	6,125	6,431	6,753	7,090	7,445	7,817	8,208	8,618	9,049	9,502	9,977	10,476	11,000	11,550	12,127	12,733	13,370	14,039
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,644	6,868	7,125	7,436	7,781	8,126	8,483	8,803	9,179	9,565	9,996	10,425	10,803	11,230	11,722	12,185	12,762	13,325	13,953	14,622
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	4	8	14	24	37	50	62	76	89	103	116	130	142	155	167	178	190	201	213	225
D.S. Options (1)	12	23	40	64	103	154	213	272	329	382	432	480	528	568	600	619	636	653	669	685
CoGen 1 (1)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen (1)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (3)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen 1 (4)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 2 (1)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CC CT (1)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CC CT (2)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)					31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (3)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CC CT (4)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Hunter 4 (1)										300	300	300	300	300	300	300	300	300	300	300
Small CT (Jul) (1)							4	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)							4	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)							4	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (4)							4	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Wyodak 2 (1)											192	192	192	192	192	192	192	192	192	192
Large CC CT (5)								175	175	175	175	175	175	175	175	175	175	175	175	175
Large CC CT (6)								175	175	175	175	175	175	175	175	175	175	175	175	175
Medium CC CT (1)									64	64	64	64	64	64	64	64	64	64	64	64
Large CC CT (7)											175	175	175	175	175	175	175	175	175	175
Large CC CT (8)												175	175	175	175	175	175	175	175	175
Large CC CT (9)												175	175	175	175	175	175	175	175	175
Large CC CT (Jul) (1)												88	175	175	175	175	175	175	175	175
Large CC CT													175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT (Jul)														88	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT																175	175	175	175	175
Large CC CT																175	175	175	175	175
Large CC CT (Jul)																88	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT (Jul)																	88	175	175	175
Large CC CT																		175	175	175
Large CC CT																		175	175	175
Large CC CT (Jul)																		88	175	175
Large CC CT (Jul)																		88	175	175
Large CC CT (Jul)																			88	175
Large CC CT (Jul)																			88	175
Large CC CT (Jul)																			88	175
Large CC CT (Jul)																			88	175
Large CT																			31	31
Large CT																			31	31
Large CT																			31	31
Large CC CT (Jul)																				88
Large CC CT (Jul)																				88
Large CC CT (Jul)																				88
Large CC CT (Jul)																				88
total	6,699	6,788	7,445	7,649	8,002	8,386	8,651	9,068	9,336	9,719	10,201	10,629	11,002	11,426	11,918	12,349	12,939	13,519	14,146	14,807
Balance	55	-80	319	213	221	260	168	265	157	154	205	204	199	196	196	164	177	194	193	186

PacifiCorp Electric Operations
4/1 RIM - Super High Forecast
Electrification Scenario

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,312	7,651	7,985	8,384	8,803	9,244	9,706	10,191	10,701	11,236	11,797	12,387	13,007	13,657	14,340	15,057	15,810	16,600	17,430	18,302
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,589	8,904	9,238	9,641	9,962	10,403	10,865	11,350	11,810	12,345	12,906	13,496	13,916	14,466	15,141	15,658	16,411	17,201	17,956	18,828
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	5	11	20	34	52	70	88	108	128	148	168	188	208	227	246	265	284	303	323	342
D.S. Options (1)	15	30	55	90	156	244	347	448	546	636	719	799	878	944	998	1,029	1,058	1,085	1,112	1,138
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (3)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen 1 (4)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (1)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (4)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)										400	400	400	400	400	400	400	400	400	400	400
Small CT (Jul) (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (4)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)											256	256	256	256	256	256	256	256	256	256
Large CC CT (5)								250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (6)								250	250	250	250	250	250	250	250	250	250	250	250	250
Medium CC CT (1)									128	128	128	128	128	128	128	128	128	128	128	128
Large CC CT (7)											250	250	250	250	250	250	250	250	250	250
Large CC CT (8)												250	250	250	250	250	250	250	250	250
Large CC CT (9)												250	250	250	250	250	250	250	250	250
Large CC CT (Jul) (1)													250	250	250	250	250	250	250	250
Large CC CT													250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT (Jul)															250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT (Jul)																	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT (Jul)																		250	250	250
Large CC CT																		250	250	250
Large CC CT																		250	250	250
Large CC CT (Jul)																			250	250
Large CC CT (Jul)																			250	250
Large CC CT (Jul)																				250
Large CC CT (Jul)																				250
Large CC CT (Jul)																				250
Large CC CT (Jul)																				250
Large CT																			156	156
Large CT																			156	156
Large CT																			156	156
Large CC CT (Jul)																				
Large CC CT (Jul)																				
Large CC CT (Jul)																				
Large CC CT (Jul)																				
total	9,482	9,872	10,668	11,097	11,745	12,250	12,958	13,801	14,083	14,651	15,285	15,882	16,445	17,035	17,729	18,297	19,051	19,848	20,696	21,760
Reserve Requirement																				
Total Company Reserve	1,300*	1,300	1,373	1,403	1,502	1,579	1,631	1,737	1,766	1,836	1,914	1,989	2,064	2,139	2,252	2,327	2,439	2,552	2,697	2,847
Balance	-407	-332	57	52	281	269	463	713	507	470	464	397	465	430	336	312	201	95	43	86
(Reserve+Balance)/Requirement	10%	11%	15%	15%	18%	18%	19%	22%	19%	19%	18%	18%	18%	18%	17%	17%	16%	15%	15%	16%

PacifiCorp Electric Operations
4/1 RIM - Super High Forecast
Electrification Scenario

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,837	7,166	7,489	7,863	8,257	8,669	9,103	9,558	10,036	10,538	11,065	11,618	12,199	12,809	13,449	14,122	14,828	15,569	16,348	17,165
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,650	8,779	9,106	9,482	9,971	10,348	10,782	11,097	11,590	11,997	12,524	13,077	13,458	13,960	14,600	15,073	15,779	16,445	17,224	18,041
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	14	24	36	48	60	73	86	99	112	125	138	150	163	175	187	200	212	224
D.S. Options (1)	12	24	43	72	128	202	290	375	459	538	614	688	762	824	875	903	930	956	981	1,006
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (3)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen 1 (4)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (1)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (4)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)										400	400	400	400	400	400	400	400	400	400	400
Small CT (Jul) (1)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (4)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)											256	256	256	256	256	256	256	256	256	256
Large CC CT (5)								250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (6)								250	250	250	250	250	250	250	250	250	250	250	250	250
Medium CC CT (1)									128	128	128	128	128	128	128	128	128	128	128	128
Large CC CT (7)											250	250	250	250	250	250	250	250	250	250
Large CC CT (8)												250	250	250	250	250	250	250	250	250
Large CC CT (9)												250	250	250	250	250	250	250	250	250
Large CC CT (Jul) (1)												250	250	250	250	250	250	250	250	250
Large CC CT													250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT (Jul)														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT (Jul)																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT (Jul)																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																		250	250	250
Large CC CT (Jul)																		250	250	250
Large CC CT (Jul)																		250	250	250
Large CC CT (Jul)																			250	250
Large CC CT (Jul)																			250	250
Large CC CT (Jul)																			250	250
Large CC CT (Jul)																			250	250
Large CT																			156	156
Large CT																			156	156
Large CT																			156	156
Large CC CT (Jul)																				250
Large CC CT (Jul)																				250
Large CC CT (Jul)																				250
Large CC CT (Jul)																				250
total	9,786	9,838	10,652	11,011	11,565	12,042	12,431	13,057	13,351	13,896	14,508	15,307	15,645	16,474	16,921	17,767	18,562	19,601	20,957	21,996
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,373	1,403	1,502	1,579	1,631	1,737	1,766	1,836	1,914	1,989	2,064	2,139	2,252	2,327	2,439	2,552	2,697	2,847
Balance	-164	-241	173	125	92	115	19	223	-5	63	70	241	123	375	69	367	344	604	1,036	1,108
(Reserve+Balance)/Requirement	13%	12%	17%	16%	16%	16%	15%	18%	15%	16%	16%	17%	16%	18%	16%	18%	18%	19%	22%	22%

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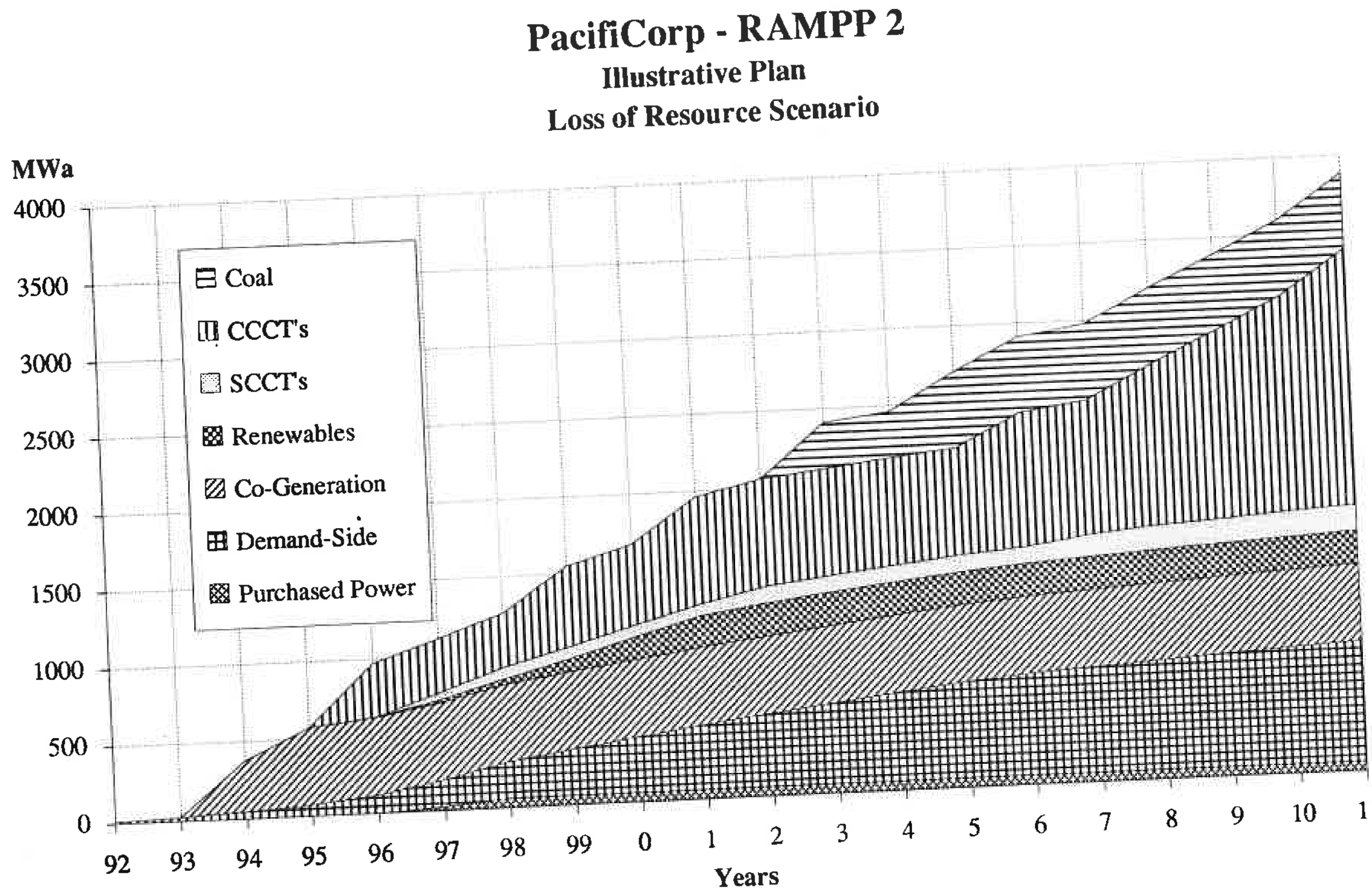
PacifiCorp - RAMPP 2
Illustrative Plan
Loss of Resource Scenario
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
Coal
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS
Loss of Resources Scenario

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6537.1	6944.3	7340.9	7772.3	8291.0	8956.9	9718.8	10667.9	11675.2	12649.8	13472.9	14163.0	14858.0	15553.3	16243.4	16885.3	17652.0	18318.6	18699.8
Net Conservation Assets	16.1	50.7	106.0	185.4	300.5	454.8	698.5	979.8	1262.7	1527.7	1763.9	1978.6	2179.6	2368.8	2529.8	2608.1	2601.0	2594.5	2579.1	2558.7
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1983.2	2171.9	2298.5	2444.0	2646.6	2827.9	3019.1	3308.1	3555.0	3894.5	4187.1	4606.9	4899.2	5377.1	5824.6	6334.8	6807.1	7341.7	7940.6
Real	1910.8	1887.0	1966.2	1979.9	2003.0	2063.8	2098.2	2131.4	2222.1	2272.0	2368.2	2422.6	2536.2	2566.2	2679.9	2762.0	2858.2	2922.2	2998.8	3086.1
NPV (9.54% discount rate)	31930.9																			
Average Growth																				
Nominal	7.79%																			
Real	2.55%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.6	50.0	51.7	54.4	57.0	59.6	63.7	66.5	71.2	74.6	80.0	82.9	89.2	94.2	99.9	104.6	110.6	117.0
Real	45.9	43.4	44.0	43.0	42.4	42.4	42.3	42.1	42.8	42.5	43.3	43.2	44.1	43.4	44.5	44.6	45.1	44.9	45.2	45.5
Average Growth																				
Nominal	5.04%																			
Real	-0.05%																			
Average Customer Bill ($)																				
Nominal	1566.3	1588.5	1712.8	1783.8	1854.8	1957.5	2040.0	2129.4	2278.0	2394.3	2566.2	2695.1	2898.7	3018.6	3249.2	3456.9	3693.5	3894.9	4116.0	4362.8
Real	1566.3	1511.4	1550.6	1536.6	1520.1	1526.5	1513.6	1503.3	1530.1	1530.2	1560.5	1559.3	1595.8	1581.2	1619.4	1639.3	1666.5	1672.1	1681.2	1695.5
NPV (9.54% discount rate)	21751.9																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1987.3	2180.9	2314.4	2469.8	2685.3	2887.5	3103.4	3418.6	3692.9	4060.8	4383.8	4835.9	5162.5	5676.0	6153.7	6675.9	7161.6	7709.0	8321.0
Real	1912.2	1890.9	1974.3	1993.6	2024.2	2094.0	2142.4	2190.9	2296.3	2360.2	2469.4	2536.4	2662.2	2704.1	2828.8	2918.1	3012.1	3074.4	3148.8	3233.9
NPV (9.54% discount rate)	32948.1																			
Average Growth																				
Nominal	8.05%																			
Real	2.80%																			
Mills / KWh																				
Nominal	45.9	45.6	48.5	49.9	51.6	54.1	56.6	59.1	62.9	65.5	69.9	73.2	78.3	81.1	87.0	91.7	96.9	101.2	106.7	112.5
Real	45.9	43.4	43.9	43.0	42.3	42.2	42.0	41.7	42.2	41.9	42.5	42.3	43.1	42.5	43.4	43.5	43.7	43.4	43.6	43.7
Average Growth																				
Nominal	4.83%																			
Real	-0.26%																			

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Loss of Resources Scenario

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	498	515	531	547	561	575	588
CoGen (1)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
BPA Out (1)		-20	-40	-60	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen 2 (1)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 2 (2)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CC CT (1)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CC CT (2)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Small CT (1)						8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (2)						8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (3)						8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Medium CT (1)						20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (3)								175	175	175	175	175	175	175	175	175	175	175	175	175
Hunter 4 (1)												300	300	300	300	300	300	300	300	300
Large CC CT (4)										175	175	175	175	175	175	175	175	175	175	175
Wyodak 2 (1)														192	192	192	192	192	192	192
Large CT (2)											31	31	31	31	31	31	31	31	31	31
Large CC CT															175	175	175	175	175	175
Small CT (Jul)																4	8	8	8	8
Small CT (Jul)																4	8	8	8	8
Small CT (Jul)																4	8	8	8	8
Small CT (Jul)																4	8	8	8	8
Medium CT																20	20	20	20	20
Large CC CT																	175	175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Small CT																			8	8
Large CC CT																				175
Large CC CT (Jul)																				88
total	6,697	6,764	7,312	7,491	7,786	7,854	8,094	8,310	8,505	8,753	8,891	9,171	9,273	9,446	9,669	9,693	9,945	10,083	10,269	10,489
Balance	180	159	519	509	578	452	499	537	516	557	464	537	516	546	563	454	496	471	453	453

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Loss of Resources Scenario

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
BPA Out (1)		-100	-200	-300	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen 2 (1)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (2)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Small CT (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Medium CT (1)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)								250	250	250	250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)												400	400	400	400	400	400	400	400	400
Large CC CT (4)										250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)														256	256	256	256	256	256	256
Large CT (2)											156	156	156	156	156	156	156	156	156	156
Large CC CT															250	250	250	250	250	250
Small CT (Jul)																	40	40	40	40
Small CT (Jul)																	40	40	40	40
Small CT (Jul)																	40	40	40	40
Small CT (Jul)																	40	40	40	40
Medium CT																100	100	100	100	100
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Small CT																			40	40
Large CC CT																				250
Large CC CT (Jul)																				
total	9,479	9,765	10,356	10,677	11,057	11,267	11,960	12,377	12,517	12,919	13,187	13,670	13,717	14,055	14,237	14,397	14,805	15,096	15,259	15,565
Reserve Requirement																				
Total Company Reserve	1,300	1,285	1,328	1,343	1,403	1,439	1,490	1,535	1,545	1,592	1,618	1,678	1,678	1,717	1,754	1,769	1,831	1,868	1,912	1,949
Balance	-153	-72	237	291	439	364	753	816	691	738	675	790	745	858	696	750	818	798	708	685
(Reserve+Balance)/Requirement	14%	14%	18%	18%	20%	19%	23%	23%	22%	22%	21%	22%	21%	22%	21%	21%	22%	21%	21%	20%

L&R - MH LoR 4/1

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Loss of Resources Scenario

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)																				
BPA Out (1)		-100	-200	-300	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen 2 (1)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (2)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Small CT (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Medium CT (1)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)								250	250	250	250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)												400	400	400	400	400	400	400	400	400
Large CC CT (4)										250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)														256	256	256	256	256	256	256
Large CT (2)											156	156	156	156	156	156	156	156	156	156
Large CC CT															250	250	250	250	250	250
Small CT (Jul)																40	40	40	40	40
Small CT (Jul)																40	40	40	40	40
Small CT (Jul)																40	40	40	40	40
Small CT (Jul)																40	40	40	40	40
Medium CT																100	100	100	100	100
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Small CT																			40	40
Large CC CT																				250
Large CC CT (Jul)																				250
total	9,783	9,733	10,342	10,595	10,882	11,066	11,281	11,643	11,794	12,175	12,423	12,858	12,931	13,258	13,444	13,794	14,083	14,367	14,539	15,072
Reserve Requirement																				
Total Company Reserve	1,300	1,285	1,328	1,343	1,403	1,439	1,490	1,535	1,545	1,592	1,618	1,678	1,678	1,717	1,754	1,769	1,831	1,868	1,912	1,949
Balance	81	8	336	331	203	146	66	200	30	158	85	164	153	274	113	363	321	377	264	476
(Reserve+Balance)/Requirement	16%	15%	19%	19%	17%	17%	16%	18%	15%	17%	16%	17%	16%	18%	16%	18%	18%	19%	18%	19%

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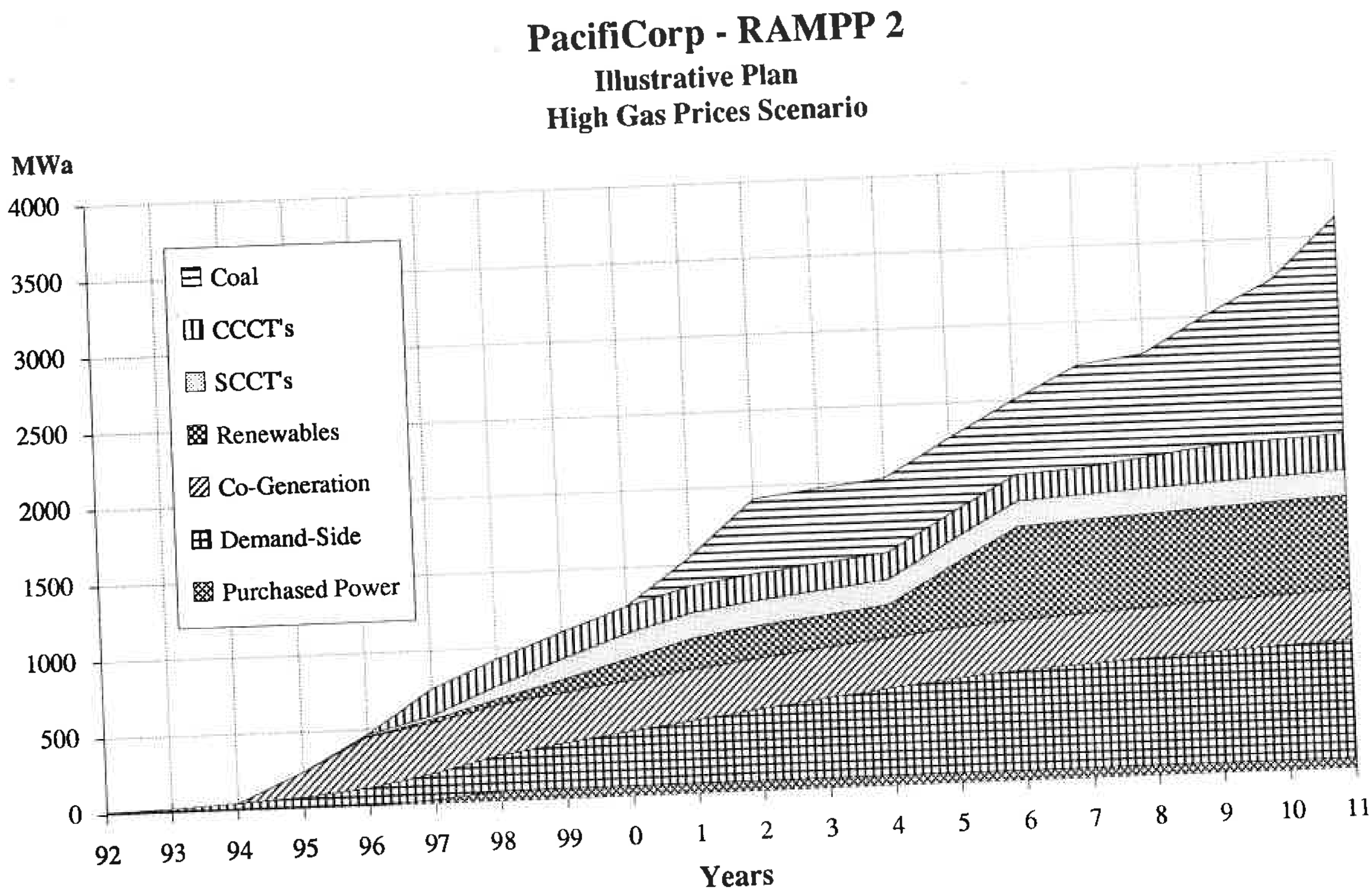
PacifiCorp - RAMPP 2
Illustrative Plan
High Gas Prices Scenario
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
Coal
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

High Gas Price Scenario

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485
Net Electric Plant (M$)	5945.7	6497.1	6789.2	7111.0	7482.5	8036.9	8972.9	10081.9	11212.6	12159.3
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)										
Nominal	1910.8	1984.0	2169.4	2277.2	2377.8	2531.9	2735.8	2955.0	3247.2	3509.3
Real	1910.8	1887.7	1964.0	1961.5	1948.8	1974.4	2029.8	2086.1	2181.2	2242.8
NPV (9.54% discount rate)	31943.6									
Average Growth										
Nominal	8.02%									
Real	2.78%									
Base Unit Cost (mills/kwh)										
Nominal	45.9	45.7	48.5	49.5	50.3	52.0	55.2	58.4	62.5	65.6
Real	45.9	43.5	43.9	42.6	41.2	40.6	40.9	41.2	42.0	42.0
Average Growth										
Nominal	5.28%									
Real	0.17%									
Average Customer Bill ($)										
Nominal	1566.3	1589.1	1710.9	1767.3	1804.5	1872.7	1973.6	2084.2	2236.1	2363.5
Real	1566.3	1512.0	1548.9	1522.3	1479.0	1460.3	1464.3	1471.4	1502.0	1510.5
NPV (9.54% discount rate)	21718.5									
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2
NPV (9.54% discount rate)	41.0									
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1
NPV (9.54% discount rate)	976.3									
Total Resource Cost (M$)										
Nominal	1912.2	1988.1	2178.4	2293.1	2403.7	2570.6	2795.3	3039.3	3357.7	3647.1
Real	1912.2	1891.7	1972.1	1975.2	1970.0	2004.6	2074.0	2145.6	2255.4	2330.9
NPV (9.54% discount rate)	32960.9									
Average Growth										
Nominal	8.27%									
Real	3.02%									
Mills / KWh										
Nominal	45.9	45.7	48.5	49.4	50.2	51.8	54.8	57.9	61.8	64.7
Real	45.9	43.4	43.9	42.6	41.1	40.4	40.7	40.9	41.5	41.4
Average Growth										
Nominal	5.05%									
Real	-0.05%									

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	12744.9	13254.8	14520.5	16365.1	17902.2	19144.1	20542.6	21957.4	23029.2	23577.7
Net Conservation Assets	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)										
Nominal	3901.4	4282.5	4576.0	4873.8	5415.7	5979.9	6575.9	7013.8	7629.1	8278.5
Real	2372.4	2477.8	2519.2	2552.9	2699.1	2835.7	2967.0	3011.0	3116.2	3217.4
Base Unit Cost (mills/kwh)										
Nominal	71.3	76.3	79.5	82.5	89.9	96.7	103.7	107.8	115.0	122.0
Real	43.4	44.1	43.8	43.2	44.8	45.8	46.8	46.3	47.0	47.4
Average Customer Bill ($)										
Nominal	2570.8	2756.5	2879.3	3003.0	3272.5	3549.1	3834.1	4013.1	4277.1	4548.4
Real	1563.3	1594.9	1585.1	1572.9	1631.0	1683.0	1729.9	1722.8	1747.0	1767.7
Customer Cost (M$)	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
Energy Services Charge (M$)	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
Total Resource Cost (M$)										
Nominal	4067.7	4479.2	4805.0	5137.1	5714.6	6309.0	6917.0	7368.3	7996.5	8658.8
Real	2473.6	2591.6	2645.2	2690.8	2848.0	2991.7	3120.9	3163.1	3266.2	3365.2
Mills / KWh										
Nominal	70.1	74.8	77.8	80.7	87.6	94.0	100.4	104.1	110.7	117.1
Real	42.6	43.3	42.8	42.2	43.7	44.6	45.3	44.7	45.2	45.5

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
High Gas Price Scenario

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Wyodak 2 (1)										192	192	192	192	192	192	192	192	192	192	192
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Hunter 4 (1)											300	300	300	300	300	300	300	300	300	300
Small CT (1)								8	8	8	8	8	8	8	8	8	8	8	8	8
Large CT (3)								31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CT (Jul) (1)								10	20	20	20	20	20	20	20	20	20	20	20	20
Medium CT (1)									20	20	20	20	20	20	20	20	20	20	20	20
New Geothermal (1)														100	100	100	100	100	100	100
New Geothermal (2)														100	100	100	100	100	100	100
New Geothermal (3)															100	100	100	100	100	100
New Geothermal (4)															100	100	100	100	100	100
AFB Coal (1)																188	188	188	188	188
Medium CC CT (Jul)																	32	64	64	64
AFB Coal																		188	188	188
AFB Coal																			188	188
AFB Coal																				188
IGCC Coal																				188
total	6,697	6,784	7,021	7,211	7,358	7,569	7,840	7,931	8,156	8,421	8,827	8,807	8,909	9,090	9,338	9,514	9,607	9,789	9,980	10,311
Balance	180	179	229	229	150	167	245	157	167	224	400	173	152	190	232	274	158	177	164	275

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
High Gas Price Scenario

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)											400	400	400	400	400	400	400	400	400	400
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (3)								156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (Jul) (1)									100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
New Geothermal (1)														100	100	100	100	100	100	100
New Geothermal (2)														100	100	100	100	100	100	100
New Geothermal (3)															100	100	100	100	100	100
New Geothermal (4)															100	100	100	100	100	100
AFB Coal (1)																250	250	250	250	250
Medium CC CT (Jul)																		128	128	128
AFB Coal																		250	250	250
AFB Coal																			250	250
AFB Coal																				250
IGCC Coal																				250
total	9,479	9,865	10,167	10,577	10,757	11,117	11,966	12,329	12,669	13,077	13,589	13,672	13,719	14,001	14,133	14,443	14,441	14,860	14,983	15,539
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,528	1,568	1,616	1,678	1,678	1,678	1,708	1,738	1,776	1,776	1,833	1,870	1,945
Balance	-153	13	77	206	184	237	758	775	821	873	1,017	791	746	812	608	789	509	597	474	663
(Reserve+Balance)/Requirement	14%	15%	16%	17%	17%	17%	23%	23%	23%	24%	25%	22%	21%	22%	20%	22%	19%	20%	19%	20%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
High Gas Price Scenario

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)											400	400	400	400	400	400	400	400	400	400
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (3)								156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (Jul) (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
New Geothermal (1)														100	100	100	100	100	100	100
New Geothermal (2)														100	100	100	100	100	100	100
New Geothermal (3)															100	100	100	100	100	100
New Geothermal (4)															100	100	100	100	100	100
AFB Coal (1)																250	250	250	250	250
Medium CC CT (Jul)																	128	128	128	128
AFB Coal																		250	250	250
AFB Coal																			250	250
AFB Coal																				250
IGCC Coal																				250
total	9,783	9,833	10,154	10,495	10,702	10,916	11,287	11,695	11,946	12,333	12,825	12,860	12,933	13,204	13,340	13,680	13,847	14,131	14,263	14,796
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,528	1,568	1,616	1,678	1,678	1,678	1,708	1,738	1,776	1,776	1,833	1,870	1,945
Balance	81	93	176	246	68	19	71	259	159	293	426	166	155	228	25	243	139	176	29	204
(Reserve+Balance)/Requirement	16%	17%	17%	18%	15%	15%	16%	18%	17%	18%	20%	17%	17%	17%	15%	17%	16%	17%	15%	17%

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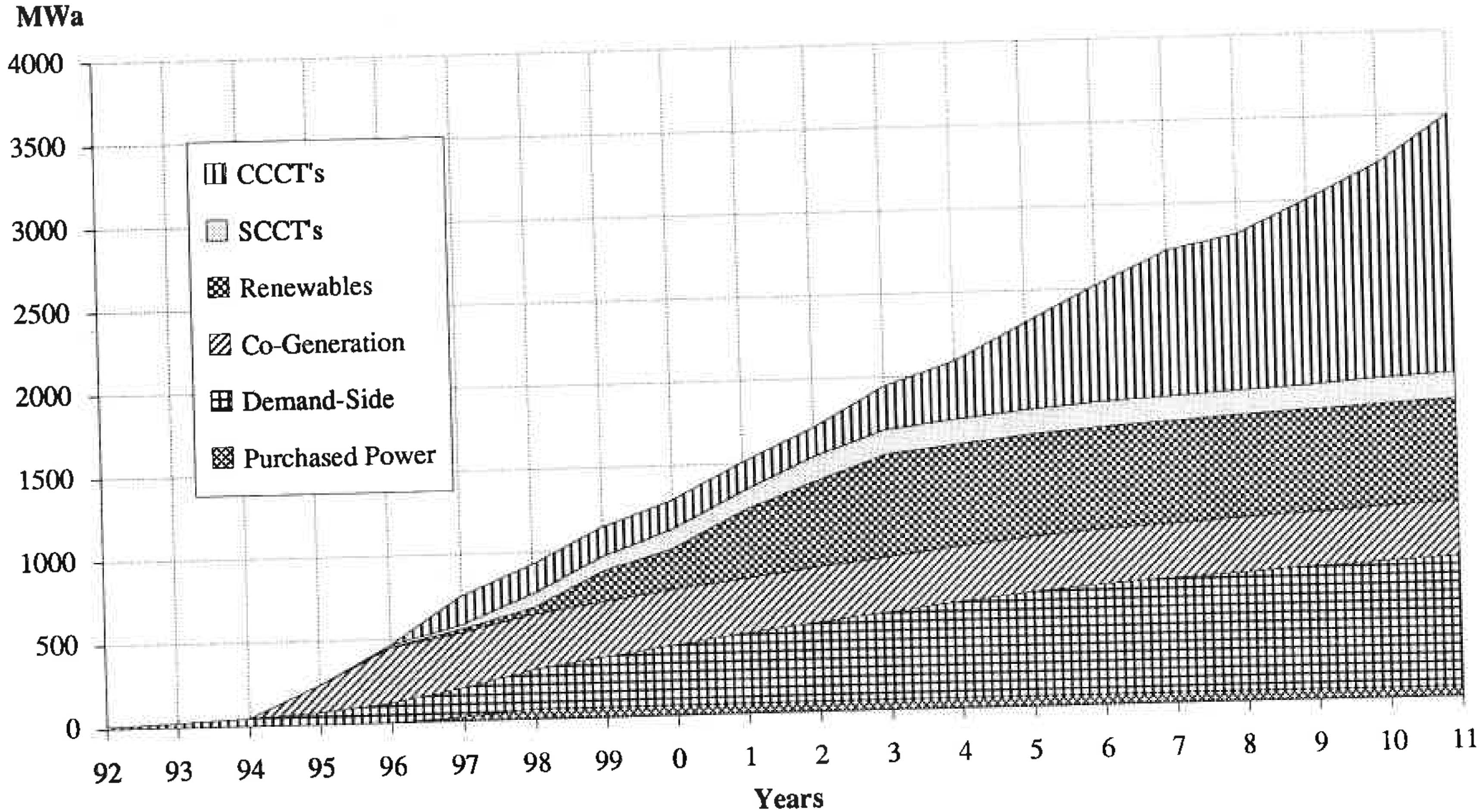
PacifiCorp - RAMPP 2
Illustrative Plan
CO2 Tax Scenario



KEY OUTPUTS

CO2 Tax Scenario

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485
Net Electric Plant (M$)	5945.7	6497.1	6789.2	7111.0	7482.5	8018.0	8836.2	9684.2	10654.0	11844.5
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)										
Nominal	1899.7	1973.7	2158.2	2268.6	2369.4	4409.0	4742.9	5094.7	5496.6	5934.6
Real	1899.7	1877.9	1953.8	1954.1	1941.9	3438.2	3519.0	3596.6	3692.1	3792.8
NPV (9.54% discount rate)	46114.0									
Average Growth										
Nominal	10.32%									
Real	4.97%									
Base Unit Cost (mills/kwh)										
Nominal	45.7	45.4	48.3	49.3	50.1	90.6	95.6	100.7	105.8	111.0
Real	45.7	43.2	43.7	42.5	41.1	70.6	71.0	71.1	71.1	70.9
Average Growth										
Nominal	7.52%									
Real	2.30%									
Average Customer Bill ($)										
Nominal	1557.1	1580.9	1702.0	1760.6	1798.1	3261.1	3421.5	3593.4	3785.0	3996.9
Real	1557.1	1504.2	1540.8	1516.6	1473.7	2543.0	2538.6	2536.8	2542.4	2554.4
NPV (9.54% discount rate)	30858.3									
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3
Levelized Customer Cost (M$)										
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2
NPV (9.54% discount rate)	41.0									
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1
NPV (9.54% discount rate)	976.3									
Total Resource Cost (M$)										
Nominal	1901.0	1977.9	2167.2	2284.5	2395.2	4447.8	4802.4	5179.0	5607.1	6072.4
Real	1901.0	1881.9	1961.9	1967.8	1963.1	3468.4	3563.2	3656.1	3766.3	3881.0
NPV (9.54% discount rate)	47131.2									
Average Growth										
Nominal	10.49%									
Real	5.13%									
Mills / KWh										
Nominal	45.6	45.4	48.2	49.3	50.0	89.6	94.2	98.6	103.1	107.7
Real	45.6	43.2	43.7	42.4	41.0	69.9	69.9	69.6	69.3	68.9
Average Growth										
Nominal	7.21%									
Real	2.00%									

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	12938.2	13701.9	14292.8	14973.1	15620.7	16205.2	16811.8	17582.0	18252.2	18636.5
Net Conservation Assets	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)										
Nominal	6405.2	6929.7	7488.4	7967.3	8525.9	9220.1	9913.4	10633.6	11380.4	12280.9
Real	3895.0	4009.4	4122.4	4173.2	4249.2	4372.2	4472.8	4564.9	4648.5	4772.9
Base Unit Cost (mills/kwh)										
Nominal	117.1	123.5	130.1	134.9	141.5	149.0	156.3	163.4	171.5	180.9
Real	71.2	71.4	71.6	70.6	70.5	70.7	70.5	70.1	70.1	70.3
Average Customer Bill ($)										
Nominal	4220.6	4460.4	4711.7	4909.0	5151.9	5472.2	5780.0	6084.4	6380.2	6747.4
Real	2566.6	2580.7	2593.9	2571.3	2567.6	2594.9	2607.9	2612.0	2606.1	2622.3
Customer Cost (M$)	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
Energy Services Charge (M$)	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
Total Resource Cost (M$)										
Nominal	6571.5	7126.4	7717.4	8230.6	8824.8	9549.3	10254.4	10988.2	11747.8	12661.2
Real	3996.1	4123.2	4248.5	4311.2	4398.1	4528.2	4626.7	4717.1	4798.5	4920.7
Mills / KWh										
Nominal	113.2	119.0	125.0	129.2	135.3	142.2	148.8	155.2	162.6	171.2
Real	68.8	68.8	68.8	67.7	67.4	67.4	67.1	66.6	66.4	66.5

KEY OUTPUTS

CO2 Tax Scenario without the tax in the financial results

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6789.2	7111.0	7482.5	8018.0	8836.2	9684.2	10654.0	11844.5	12938.2	13701.9	14292.8	14973.1	15620.7	16205.2	16811.8	17582.0	18252.2	18636.5
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.5	2169.9	2280.2	2381.0	2562.5	2772.1	2993.8	3305.9	3570.5	3936.7	4301.4	4730.7	5027.2	5377.8	5812.4	6451.4	6848.3	7389.9	7987.9
Real	1910.8	1888.2	1964.4	1964.1	1951.4	1998.2	2056.8	2113.5	2220.6	2281.9	2393.9	2488.7	2604.3	2633.3	2680.2	2756.2	2910.8	2939.9	3018.5	3104.4
NPV (9.54% discount rate)	31969.8																			
Average Growth																				
Nominal	7.82%																			
Real	2.59%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.6	50.4	52.7	55.9	59.1	63.6	66.8	72.0	76.6	82.2	85.1	89.3	94.0	101.7	105.2	111.4	117.7
Real	45.9	43.5	43.9	42.7	41.3	41.1	41.5	41.8	42.7	42.7	43.8	44.3	45.2	44.6	44.5	44.6	45.9	45.2	45.5	45.7
Average Growth																				
Nominal	5.08%																			
Real	-0.02%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.5	1711.3	1769.7	1807.0	1895.3	1999.8	2111.6	2276.5	2404.7	2594.0	2768.6	2976.6	3097.5	3249.6	3449.7	3761.5	3918.4	4143.0	4388.7
Real	1566.3	1512.4	1549.2	1524.4	1480.9	1478.0	1483.7	1490.7	1529.1	1536.9	1577.4	1601.9	1638.7	1622.5	1619.5	1635.8	1697.1	1682.2	1692.3	1705.6
NPV (9.54% discount rate)	21756.6																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.7	2178.9	2296.2	2406.9	2601.2	2831.6	3078.1	3416.4	3708.3	4103.0	4498.1	4959.7	5290.5	5676.7	6141.5	6792.5	7202.8	7757.2	8368.3
Real	1912.2	1892.2	1972.6	1977.9	1972.6	2028.4	2101.0	2173.0	2294.8	2370.0	2495.0	2602.5	2730.4	2771.2	2829.1	2912.3	3064.7	3092.1	3168.5	3252.3
NPV (9.54% discount rate)	32987.0																			
Average Growth																				
Nominal	8.08%																			
Real	2.83%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.5	50.3	52.4	55.5	58.6	62.8	65.8	70.7	75.1	80.3	83.1	87.0	91.5	98.6	101.8	107.4	113.2
Real	45.9	43.4	43.9	42.6	41.2	40.9	41.2	41.4	42.2	42.1	43.0	43.4	44.2	43.5	43.4	43.4	44.5	43.7	43.9	44.0
Average Growth																				
Nominal	4.86%																			
Real	-0.23%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
CO2 Tax Scenario

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	56	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
New Geothermal (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
New Geothermal (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)											100	100	100	100	100	100	100	100	100	100
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
New Geothermal (4)												100	100	100	100	100	100	100	100	100
Large CT (4)											31	31	31	31	31	31	31	31	31	31
Large CC CT (Jul) (1)												88	175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT																175	175	175	175	175
Medium CC CT																	64	64	64	64
Large CC CT																		175	175	175
Large CC CT																			175	175
Small CT																			8	8
Large CC CT																				175
Large CC CT (Jul)																				88
total	6,697	6,784	7,021	7,211	7,358	7,569	7,840	7,981	8,208	8,381	8,618	8,787	8,975	9,131	9,354	9,517	9,643	9,780	9,966	10,186
Balance	180	179	229	229	150	167	245	208	219	184	192	153	218	231	248	278	194	169	150	150

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
CO2 Tax Scenario

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
New Geothermal (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)											100	100	100	100	100	100	100	100	100	100
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (4)												100	100	100	100	100	100	100	100	100
Large CT (4)											156	156	156	156	156	156	156	156	156	156
Large CC CT (Jul) (1)													250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Medium CC CT																	128	128	128	128
Large CC CT																		250	250	250
Large CC CT																			250	250
Small CT																			40	40
Large CC CT																				250
Large CC CT (Jul)																				
total	9,479	9,865	10,167	10,577	10,757	11,117	11,966	12,233	12,529	12,781	13,149	13,332	13,629	13,961	14,143	14,453	14,579	14,870	15,033	15,339
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,514	1,547	1,572	1,612	1,627	1,665	1,702	1,740	1,777	1,797	1,834	1,878	1,915
Balance	-153	13	77	206	184	237	758	694	702	621	643	502	670	778	616	797	626	606	516	493
(Reserve+Balance)/Requirement	14%	15%	16%	17%	17%	17%	23%	22%	22%	21%	21%	19%	21%	22%	20%	22%	20%	20%	19%	19%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
CO2 Tax Scenario

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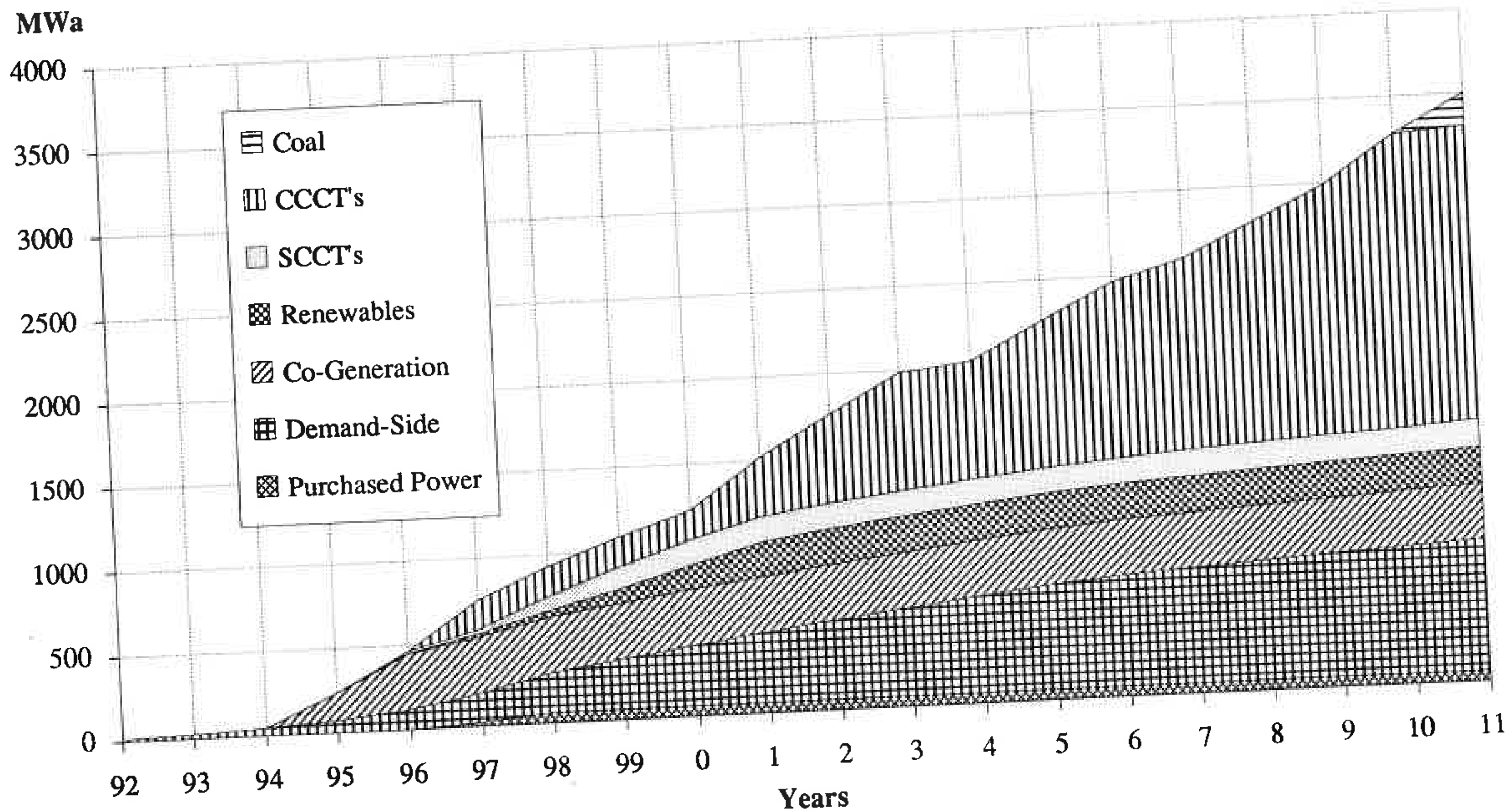
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
New Geothermal (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)											100	100	100	100	100	100	100	100	100	100
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (4)												100	100	100	100	100	100	100	100	100
Large CT (4)											156	156	156	156	156	156	156	156	156	156
Large CC CT (Jul) (1)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Medium CC CT																	128	128	128	128
Large CC CT																		250	250	250
Large CC CT																			250	250
Small CT																			40	40
Large CC CT																				250
Large CC CT (Jul)																				250
total	9,783	9,833	10,154	10,495	10,702	10,916	11,287	11,499	11,806	12,037	12,385	12,770	12,843	13,164	13,350	13,690	13,857	14,141	14,313	14,846
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,514	1,547	1,572	1,612	1,627	1,665	1,702	1,740	1,777	1,797	1,834	1,878	1,915
Balance	81	93	176	246	68	19	71	77	40	41	52	127	78	194	34	251	129	185	72	284
(Reserve+Balance)/Requirement	16%	17%	17%	18%	15%	15%	16%	16%	16%	15%	16%	16%	16%	17%	15%	17%	16%	17%	16%	17%

PacifiCorp - RAMPP 2

Illustrative Plan
Environmental Level 1



KEY OUTPUTS
Environmental Level 1

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6789.2	7111.0	7482.5	7983.9	8695.1	9469.5	10331.6	11130.8	11768.8	12326.5	12957.6	13694.0	14450.8	15232.4	16079.6	16903.8	17618.0	18098.8
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.4	2277.2	2377.8	2531.2	2726.2	2940.2	3218.0	3476.3	3810.7	4127.0	4477.2	4778.3	5212.7	5681.0	6237.3	6719.2	7277.6	7877.4
Real	1910.8	1887.7	1964.0	1961.5	1948.8	1973.9	2022.8	2075.7	2161.5	2221.8	2317.3	2387.8	2464.8	2502.9	2597.9	2693.9	2814.2	2884.5	2972.6	3061.5
NPV (9.54% discount rate)	31331.9																			
Average Growth																				
Nominal	7.74%																			
Real	2.51%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.3	52.0	55.0	58.1	61.9	65.0	69.6	73.5	77.8	80.9	86.5	91.8	98.3	103.3	109.7	116.1
Real	45.9	43.5	43.9	42.6	41.2	40.6	40.8	41.0	41.6	41.6	42.4	42.5	42.8	42.4	43.1	43.5	44.4	44.3	44.8	45.1
Average Growth																				
Nominal	5.00%																			
Real	-0.09%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1710.9	1767.3	1804.5	1872.2	1966.7	2073.8	2215.9	2341.3	2511.0	2656.4	2817.1	2944.1	3149.8	3371.7	3636.7	3844.6	4080.0	4328.0
Real	1566.3	1512.0	1548.9	1522.3	1479.0	1460.0	1459.2	1464.0	1488.4	1496.3	1526.9	1537.0	1550.8	1542.1	1569.8	1598.8	1640.8	1650.5	1666.5	1682.0
NPV (9.54% discount rate)	21351.1																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.1	2178.4	2293.1	2403.7	2570.0	2785.8	3024.5	3328.4	3614.2	3977.0	4323.7	4706.2	5041.6	5511.6	6010.1	6578.4	7073.7	7644.9	8257.8
Real	1912.2	1891.7	1972.1	1975.2	1970.0	2004.1	2067.0	2135.2	2235.7	2309.9	2418.4	2501.7	2590.8	2640.8	2746.9	2850.0	2968.1	3036.7	3122.7	3209.3
NPV (9.54% discount rate)	32349.1																			
Average Growth																				
Nominal	8.00%																			
Real	2.76%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.2	51.8	54.6	57.6	61.2	64.1	68.5	72.2	76.2	79.2	84.5	89.5	95.5	99.9	105.8	111.7
Real	45.9	43.4	43.9	42.6	41.1	40.4	40.5	40.7	41.1	41.0	41.7	41.8	42.0	41.5	42.1	42.4	43.1	42.9	43.2	43.4
Average Growth																				
Nominal	4.79%																			
Real	-0.30%																			

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PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Environmental Level 1

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Small CT (1)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (2)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (3)								8	8	8	8	8	8	8	8	8	8	8	8	8
Medium CT (1)								20	20	20	20	20	20	20	20	20	20	20	20	20
Medium CT (2)									20	20	20	20	20	20	20	20	20	20	20	20
Large CC CT (2)										175	175	175	175	175	175	175	175	175	175	175
Large CC CT (3)											175	175	175	175	175	175	175	175	175	175
Large CC CT (4)												175	175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT (Jul)																88	175	175	175	175
Small CT																8	8	8	8	8
Large CC CT (Jul)																	88	175	175	175
Large CC CT (Jul)																		88	175	175
Large CC CT																			175	175
Wyodak 2																				192
Medium CT (Jul)																				10
total	6,697	6,784	7,021	7,211	7,358	7,569	7,840	7,925	8,140	8,389	8,670	8,825	8,927	9,083	9,306	9,390	9,626	9,764	10,029	10,187
Balance	180	179	229	229	150	167	245	152	151	192	243	191	170	183	200	151	177	152	213	151

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L&R - ES1

PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Environmental Level 1

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Winter Peak

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588
Resources										
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545
BPA Entitlement (1)							164	164	164	164
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						16	39	39	55	71
CoGen (1)				94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40
Large CC CT (1)						250	250	250	250	250
Large CT (1)							156	156	156	156
Large CT (2)							156	156	156	156
Small CT (1)								40	40	40
Small CT (2)								40	40	40
Small CT (3)								40	40	40
Medium CT (1)								100	100	100
Medium CT (2)									100	100
Large CC CT (2)										250
Large CC CT (3)										
Large CC CT (4)										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
Small CT										
Large CC CT (Jul)										
Large CC CT (Jul)										
Large CC CT										
Wyodak 2										
Medium CT (Jul)										
total	9,479	9,865	10,167	10,577	10,757	11,117	11,966	12,353	12,593	12,995
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,556	1,604
Balance	-153	13	77	206	184	237	758	796	756	803
(Reserve+Balance)/Requirement	14%	15%	16%	17%	17%	17%	23%	23%	22%	23%

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,109	1,109	909	809	801	601	601	601	526	526
total	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources										
Existing Generation	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	87	87	87	87	87	87	87	87	87	87
CoGen (1)	94	94	94	94	94	94	94	94	94	94
CoGen (2)	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Large CT (2)	156	156	156	156	156	156	156	156	156	156
Small CT (1)	40	40	40	40	40	40	40	40	40	40
Small CT (2)	40	40	40	40	40	40	40	40	40	40
Small CT (3)	40	40	40	40	40	40	40	40	40	40
Medium CT (1)	100	100	100	100	100	100	100	100	100	100
Medium CT (2)	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)	250	250	250	250	250	250	250	250	250	250
Large CC CT (4)		250	250	250	250	250	250	250	250	250
Large CC CT				250	250	250	250	250	250	250
Large CC CT					250	250	250	250	250	250
Large CC CT (Jul)							250	250	250	250
Small CT						40	40	40	40	40
Large CC CT (Jul)								250	250	250
Large CC CT (Jul)									250	250
Large CC CT									250	250
Wyodak 2										256
Medium CT (Jul)										
total	13,357	13,690	13,737	14,069	14,251	14,351	14,599	14,890	15,263	15,575
Reserve Requirement										
Total Company Reserve	1,644	1,681	1,681	1,719	1,756	1,762	1,800	1,837	1,912	1,951
Balance	820	807	762	870	708	711	643	623	712	694
(Reserve+Balance)/Requirement	23%	22%	22%	23%	21%	21%	20%	20%	21%	20%

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PacifiCorp Electric Operations
3/4 RIM - Medium High Forecast
Environmental Level 1

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424
Resources										
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452
BPA Entitlement (1)										
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						10	25	25	35	45
CoGen (1)				94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40
Small CT (Jul) (2)					40	40	40	40	40	40
Small CT (Jul) (3)					40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250
Large CT (1)							156	156	156	156
Large CT (2)							156	156	156	156
Small CT (1)								40	40	40
Small CT (2)								40	40	40
Small CT (3)								40	40	40
Medium CT (1)								100	100	100
Medium CT (2)									100	100
Large CC CT (2)										250
Large CC CT (3)										
Large CC CT (4)										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
Small CT										
Large CC CT (Jul)										
Large CC CT (Jul)										
Large CC CT										
Wyodak 2										
Medium CT (Jul)										
total	9,783	9,833	10,154	10,495	10,702	10,916	11,287	11,619	11,870	12,251
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,556	1,604
Balance	81	93	176	246	68	19	71	179	95	223
(Reserve+Balance)/Requirement	16%	17%	17%	18%	15%	15%	16%	17%	16%	18%

Summer Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources										
Existing Generation	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)										
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	55	55	55	55	55	55	55	55	55	55
CoGen (1)	94	94	94	94	94	94	94	94	94	94
CoGen (2)	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Large CT (2)	156	156	156	156	156	156	156	156	156	156
Small CT (1)	40	40	40	40	40	40	40	40	40	40
Small CT (2)	40	40	40	40	40	40	40	40	40	40
Small CT (3)	40	40	40	40	40	40	40	40	40	40
Medium CT (1)	100	100	100	100	100	100	100	100	100	100
Medium CT (2)	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)	250	250	250	250	250	250	250	250	250	250
Large CC CT (4)		250	250	250	250	250	250	250	250	250
Large CC CT				250	250	250	250	250	250	250
Large CC CT					250	250	250	250	250	250
Large CC CT (Jul)						250	250	250	250	250
Small CT						40	40	40	40	40
Large CC CT (Jul)							250	250	250	250
Large CC CT (Jul)								250	250	250
Large CC CT									250	250
Wyodak 2										256
Medium CT (Jul)										100
total	12,593	12,878	12,951	13,272	13,458	13,838	14,127	14,411	14,543	14,932
Reserve Requirement										
Total Company Reserve	1,644	1,681	1,681	1,719	1,756	1,762	1,800	1,837	1,912	1,951
Balance	229	181	170	286	125	414	396	452	267	335
(Reserve+Balance)/Requirement	17%	17%	17%	18%	16%	19%	18%	19%	18%	18%

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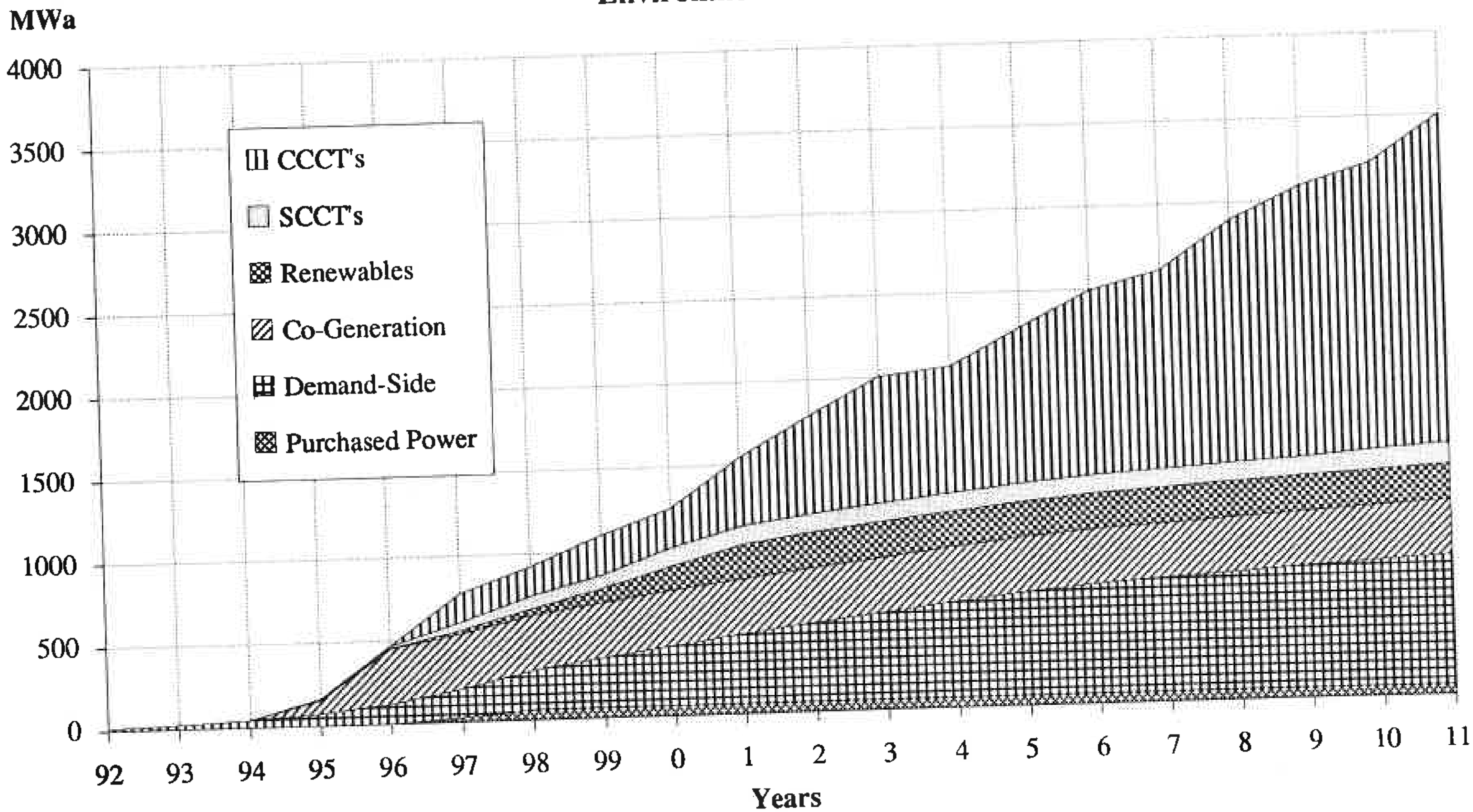
L&R - ES1

PacifiCorp - RAMPP 2

Illustrative Plan
Environmental Level 2



KEY OUTPUTS
Environmental Level 2

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6499.8	6800.8	7114.7	7515.5	8044.0	8689.7	9449.5	10332.6	11132.6	11771.4	12329.9	12961.8	13694.8	14429.7	15114.2	15758.1	16442.7	16986.8	17301.9
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.6	2277.2	2386.2	2526.3	2741.6	2932.7	3203.1	3472.3	3805.4	4122.5	4472.6	4773.5	5207.9	5675.1	6216.0	6696.4	7250.5	7878.9
Real	1910.8	1887.7	1964.1	1961.5	1955.7	1970.0	2034.2	2070.4	2151.6	2219.2	2314.1	2385.3	2462.2	2500.4	2595.5	2691.1	2804.6	2874.7	2961.6	3062.1
NPV (9.54% discount rate)	31306.4																			
Average Growth																				
Nominal	7.74%																			
Real	2.51%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.5	51.9	55.3	57.9	61.6	65.0	69.6	73.5	77.7	80.8	86.4	91.7	98.0	102.9	109.3	116.1
Real	45.9	43.5	43.9	42.6	41.4	40.5	41.0	40.9	41.4	41.5	42.3	42.5	42.8	42.3	43.1	43.5	44.2	44.2	44.6	45.1
Average Growth																				
Nominal	5.00%																			
Real	-0.09%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1711.0	1767.3	1810.9	1868.5	1977.8	2068.5	2205.7	2338.6	2507.5	2653.5	2814.2	2941.2	3147.0	3368.2	3624.3	3831.5	4064.9	4328.8
Real	1566.3	1512.0	1549.0	1522.3	1484.2	1457.1	1467.4	1460.3	1481.6	1494.6	1524.8	1535.3	1549.2	1540.6	1568.4	1597.2	1635.2	1644.9	1660.3	1682.4
NPV (9.54% discount rate)	21336.4																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.2	2178.6	2293.1	2412.1	2565.0	2801.2	3017.0	3313.6	3610.2	3971.7	4319.2	4701.6	5036.8	5506.8	6004.2	6557.0	7050.9	7617.9	8259.3
Real	1912.2	1891.7	1972.3	1975.3	1976.9	2000.2	2078.4	2129.9	2225.8	2307.3	2415.2	2499.1	2588.3	2638.3	2744.5	2847.2	2958.4	3026.9	3111.6	3209.9
NPV (9.54% discount rate)	32323.6																			
Average Growth																				
Nominal	8.00%																			
Real	2.76%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.4	51.7	54.9	57.5	61.0	64.1	68.4	72.1	76.1	79.1	84.4	89.4	95.2	99.6	105.5	111.7
Real	45.9	43.4	43.9	42.6	41.3	40.3	40.8	40.6	40.9	40.9	41.6	41.7	41.9	41.4	42.1	42.4	42.9	42.8	43.1	43.4
Average Growth																				
Nominal	4.79%																			
Real	-0.29%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 2

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Small CT (1)				8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)						31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CC CT (1)								64	64	64	64	64	64	64	64	64	64	64	64	64
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (2)										175	175	175	175	175	175	175	175	175	175	175
Large CC CT (3)											175	175	175	175	175	175	175	175	175	175
Large CC CT (4)												175	175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT (Jul)																88	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT																		175	175	175
Large CC CT (Jul)																			88	175
Small CT																			8	8
Small CT																			8	8
Large CC CT																				175
total	6,697	6,784	7,021	7,139	7,358	7,592	7,832	7,937	8,164	8,412	8,693	8,848	8,950	9,106	9,329	9,405	9,729	9,866	9,973	10,192
Balance	180	179	229	157	150	190	237	164	175	215	266	214	193	206	223	166	279	254	157	156

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 2

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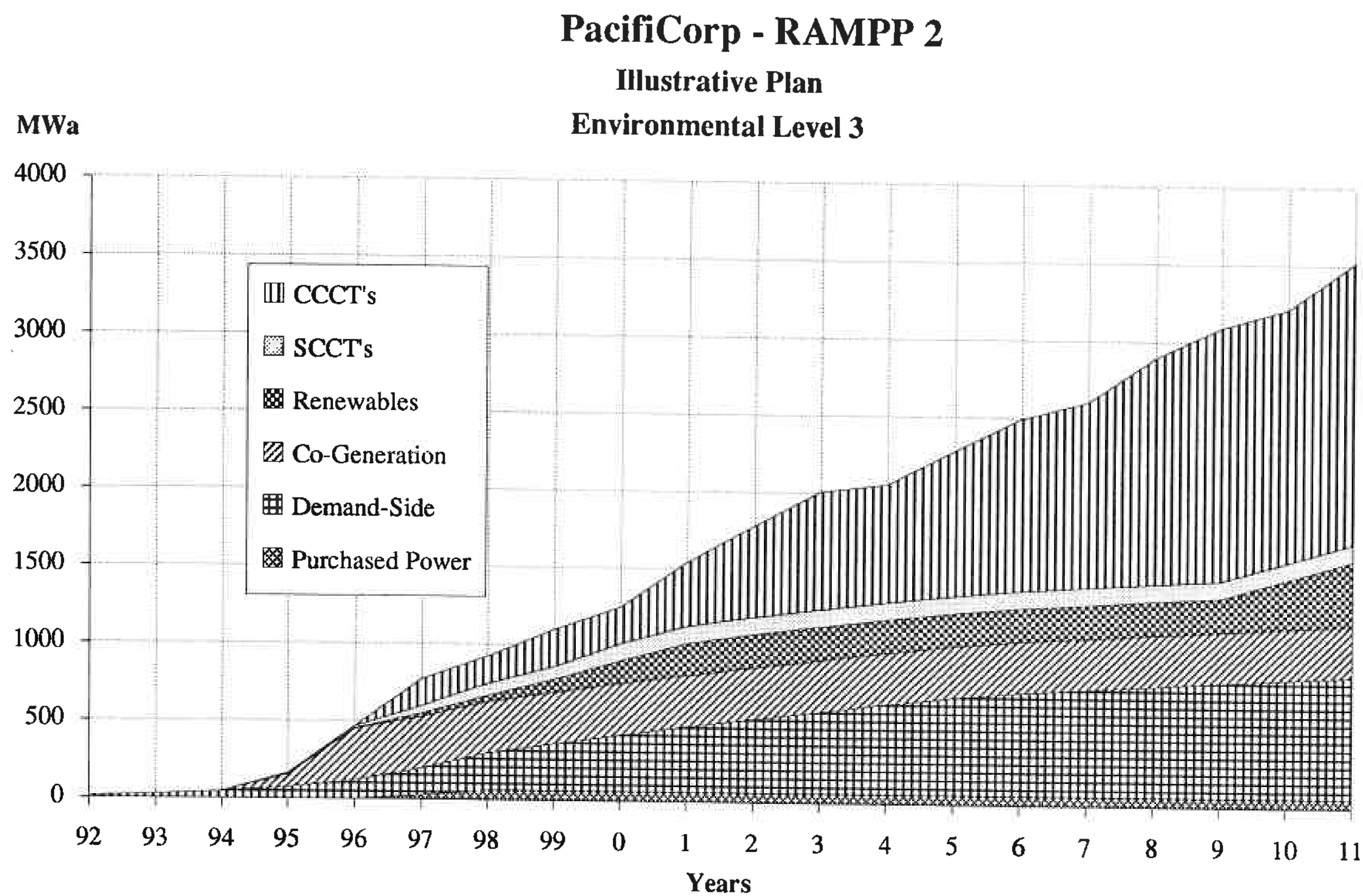
Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CC CT (1)								128	128	128	128	128	128	128	128	128	128	128	128	128
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)											250	250	250	250	250	250	250	250	250	250
Large CC CT (4)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT (Jul)																				250
Small CT																			40	40
Small CT																			40	40
Large CC CT																				250
total	9,479	9,865	10,167	10,523	10,797	11,233	11,926	12,221	12,517	12,919	13,281	13,614	13,661	13,993	14,175	14,235	14,733	15,024	14,977	15,533
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,364	1,434	1,485	1,512	1,545	1,592	1,632	1,670	1,670	1,707	1,745	1,745	1,820	1,857	1,869	1,944
Balance	-153	13	77	160	218	336	724	683	691	738	755	742	697	805	644	612	757	737	469	658
(Reserve+Balance)/Requirement	14%	15%	16%	16%	17%	19%	23%	22%	22%	22%	22%	22%	21%	22%	20%	20%	21%	21%	18%	20%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 2

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CC CT (1)								128	128	128	128	128	128	128	128	128	128	128	128	128
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)											250	250	250	250	250	250	250	250	250	250
Large CC CT (4)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT (Jul)																			250	250
Small CT																			40	40
Small CT																			40	40
Large CC CT																				250
total	9,783	9,833	10,154	10,441	10,662	11,032	11,247	11,487	11,794	12,175	12,517	12,802	12,875	13,196	13,382	13,722	14,011	14,295	14,507	14,790
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,364	1,434	1,485	1,512	1,545	1,592	1,632	1,670	1,670	1,707	1,745	1,745	1,820	1,857	1,869	1,944
Balance	81	93	176	200	22	117	37	67	30	158	164	116	105	221	61	316	260	316	274	199
(Reserve+Balance)/Requirement	16%	17%	17%	17%	15%	16%	16%	16%	15%	17%	17%	16%	16%	17%	16%	18%	17%	18%	17%	17%



PacifiCorp - RAMPP 2
Illustrative Plan
Environmental Level 3
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

Environmental Level 3

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6499.8	6800.8	7114.7	7515.5	8044.0	8689.7	9449.5	10332.6	11132.6	11771.4	12329.9	12961.8	13694.8	14429.7	15074.8	15652.2	16564.5	17680.4	18336.3
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.6	2277.2	2386.2	2526.3	2741.6	2932.7	3203.1	3472.3	3805.4	4122.5	4472.6	4773.5	5207.9	5674.6	6214.6	6697.9	7259.1	7893.1
Real	1910.8	1887.7	1964.1	1961.5	1955.7	1970.0	2034.2	2070.4	2151.6	2219.2	2314.1	2385.3	2462.2	2500.4	2595.5	2690.9	2804.0	2875.3	2965.1	3067.6
NPV (9.54% discount rate)	31310.4																			
Average Growth																				
Nominal	7.75%																			
Real	2.52%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.5	51.9	55.3	57.9	61.6	65.0	69.6	73.5	77.7	80.8	86.4	91.7	98.0	102.9	109.4	116.3
Real	45.9	43.5	43.9	42.6	41.4	40.5	41.0	40.9	41.4	41.5	42.3	42.5	42.8	42.3	43.1	43.5	44.2	44.2	44.7	45.2
Average Growth																				
Nominal	5.01%																			
Real	-0.08%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1711.0	1767.3	1810.9	1868.5	1977.8	2068.5	2205.7	2338.6	2507.5	2653.5	2814.2	2941.2	3147.0	3367.9	3623.5	3832.4	4069.7	4336.6
Real	1566.3	1512.0	1549.0	1522.3	1484.2	1457.1	1467.4	1460.3	1481.6	1494.6	1524.8	1535.3	1549.2	1540.6	1568.4	1597.1	1634.9	1645.2	1662.3	1685.4
NPV (9.54% discount rate)	21338.6																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.2	2178.6	2293.1	2412.1	2565.0	2801.2	3017.0	3313.6	3610.2	3971.7	4319.2	4701.6	5036.8	5506.8	6003.7	6555.7	7052.4	7626.5	8273.4
Real	1912.2	1891.7	1972.3	1975.3	1976.9	2000.2	2078.4	2129.9	2225.8	2307.3	2415.2	2499.1	2588.3	2638.3	2744.5	2847.0	2957.9	3027.5	3115.1	3215.4
NPV (9.54% discount rate)	32327.7																			
Average Growth																				
Nominal	8.01%																			
Real	2.77%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.4	51.7	54.9	57.5	61.0	64.1	68.4	72.1	76.1	79.1	84.4	89.4	95.1	99.6	105.6	111.9
Real	45.9	43.4	43.9	42.6	41.3	40.3	40.8	40.6	40.9	40.9	41.6	41.7	41.9	41.4	42.1	42.4	42.9	42.8	43.1	43.5
Average Growth																				
Nominal	4.80%																			
Real	-0.29%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 3

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Small CT (1)				8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)						31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CC CT (1)								64	64	64	64	64	64	64	64	64	64	64	64	64
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (2)										175	175	175	175	175	175	175	175	175	175	175
Large CC CT (3)											175	175	175	175	175	175	175	175	175	175
Large CC CT (4)												175	175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT (Jul)																88	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT																		175	175	175
New Geothermal																			100	100
Large CC CT																				175
New Geothermal																				100
total	6,697	6,784	7,021	7,139	7,358	7,592	7,832	7,937	8,164	8,412	8,693	8,848	8,950	9,106	9,329	9,405	9,729	9,866	9,969	10,201
Balance	180	179	229	157	150	190	237	164	175	215	266	214	193	206	223	166	279	254	153	165

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 3

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588
Resources										
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545
BPA Entitlement (1)							164	164	164	164
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						16	39	39	55	71
CoGen (1)				94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40
CoGen (2)					94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40
Large CC CT (1)						250	250	250	250	250
Large CT (1)						156	156	156	156	156
Large CT (2)							156	156	156	156
Medium CC CT (1)								128	128	128
Large CT (3)									156	156
Large CC CT (2)										250
Large CC CT (3)										
Large CC CT (4)										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
Large CC CT										
Large CC CT										
New Geothermal										
Large CC CT										
New Geothermal										
total	9,479	9,865	10,167	10,523	10,797	11,233	11,926	12,221	12,517	12,919
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,320	1,364	1,434	1,485	1,512	1,545	1,592
Balance	-153	13	77	160	218	336	724	683	691	738
(Reserve+Balance)/Requirement	14%	15%	16%	16%	17%	19%	23%	22%	22%	22%

Winter Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,109	1,109	909	809	801	601	601	601	526	526
total	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources										
Existing Generation	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	87	87	87	87	87	87	87	87	87	87
CoGen (1)	94	94	94	94	94	94	94	94	94	94
Small CT (1)	40	40	40	40	40	40	40	40	40	40
CoGen (2)	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Large CT (2)	156	156	156	156	156	156	156	156	156	156
Medium CC CT (1)	128	128	128	128	128	128	128	128	128	128
Large CT (3)	156	156	156	156	156	156	156	156	156	156
Large CC CT (2)	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)	250	250	250	250	250	250	250	250	250	250
Large CC CT (4)		250	250	250	250	250	250	250	250	250
Large CC CT				250	250	250	250	250	250	250
Large CC CT					250	250	250	250	250	250
Large CC CT (Jul)							250	250	250	250
Large CC CT							250	250	250	250
Large CC CT								250	250	250
New Geothermal									100	100
Large CC CT										250
New Geothermal										100
total	13,281	13,614	13,661	13,993	14,175	14,235	14,733	15,024	14,997	15,403
Reserve Requirement										
Total Company Reserve	1,632	1,670	1,670	1,707	1,745	1,745	1,820	1,857	1,872	1,925
Balance	755	742	697	805	644	612	757	737	486	547
(Reserve+Balance)/Requirement	22%	22%	21%	22%	20%	20%	21%	21%	19%	19%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 3

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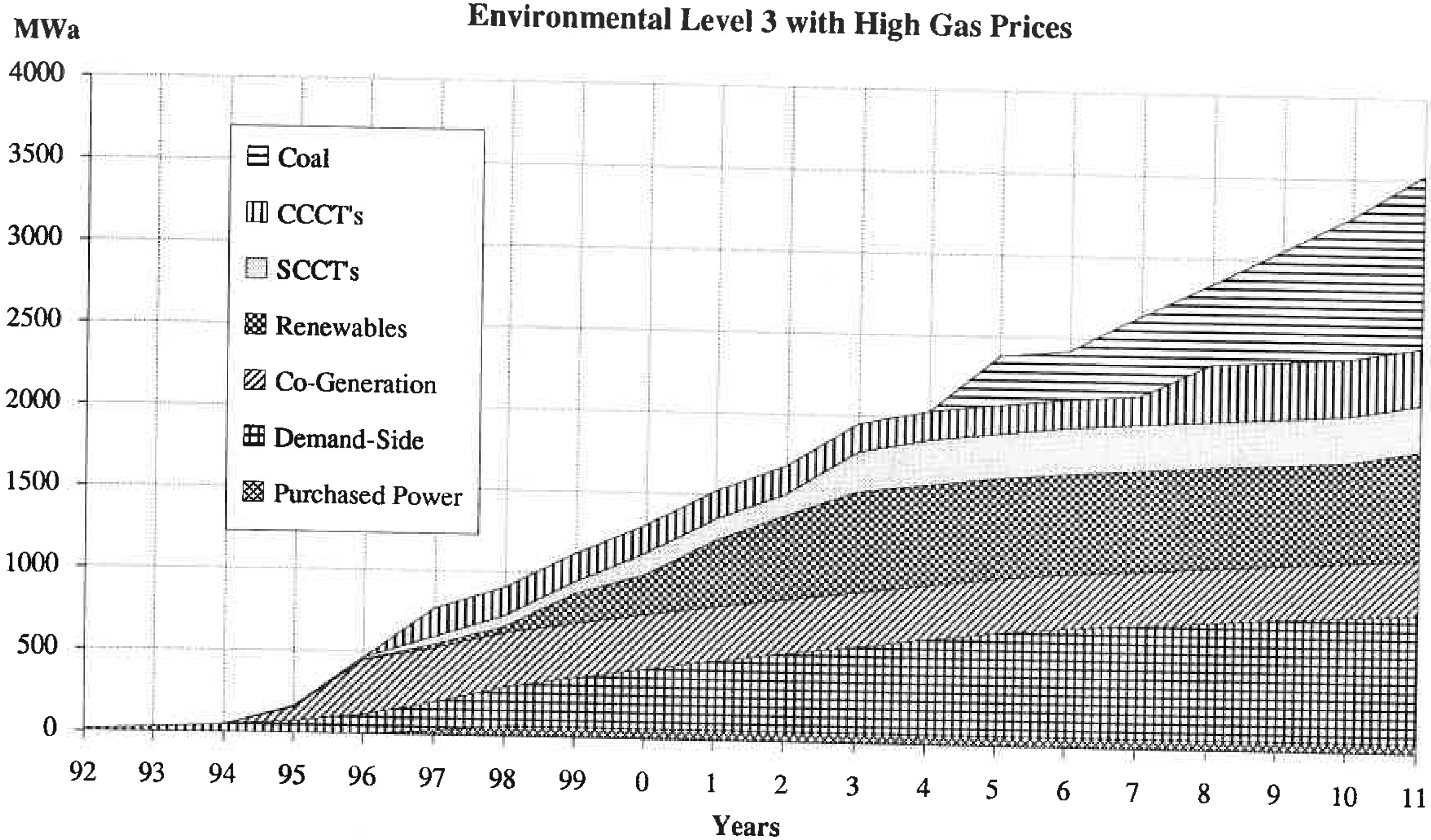
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CC CT (1)								128	128	128	128	128	128	128	128	128	128	128	128	128
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)											250	250	250	250	250	250	250	250	250	250
Large CC CT (4)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
New Geothermal																			100	100
Large CC CT																				250
New Geothermal																				100
total	9,783	9,833	10,154	10,441	10,662	11,032	11,247	11,487	11,794	12,175	12,517	12,802	12,875	13,196	13,382	13,722	14,011	14,295	14,277	14,660
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,364	1,434	1,485	1,512	1,545	1,592	1,632	1,670	1,670	1,707	1,745	1,745	1,820	1,857	1,872	1,925
Balance	81	93	176	200	22	117	37	67	30	158	164	116	105	221	61	316	260	316	41	89
(Reserve+Balance)/Requirement	16%	17%	17%	17%	15%	16%	16%	16%	15%	17%	17%	16%	16%	17%	16%	18%	17%	18%	15%	16%

PacifiCorp - RAMPP 2

Illustrative Plan

Environmental Level 3 with High Gas Prices



KEY OUTPUTS
Environmental Level 3 w/ High Gas

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6499.8	6800.8	7114.7	7497.0	8003.4	8768.1	9677.8	10660.1	11812.4	13220.7	14467.8	15394.6	16333.1	17375.5	18623.9	19826.1	20913.5	21690.0	22358.7
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.6	2277.2	2386.0	2525.7	2748.9	2934.0	3248.6	3546.4	3916.2	4264.2	4746.3	5068.8	5555.7	5952.8	6531.1	6994.8	7628.0	8309.0
Real	1910.8	1887.7	1964.1	1961.5	1955.5	1969.6	2039.6	2071.3	2182.1	2266.5	2381.4	2467.2	2612.9	2655.0	2768.9	2822.8	2946.7	3002.8	3115.8	3229.2
NPV (9.54% discount rate)	32097.9																			
Average Growth																				
Nominal	8.04%																			
Real	2.80%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.5	51.9	55.4	58.0	62.5	66.3	71.6	76.0	82.5	85.8	92.2	96.2	103.0	107.5	115.0	122.4
Real	45.9	43.5	43.9	42.6	41.4	40.5	41.1	40.9	42.0	42.4	43.5	44.0	45.4	44.9	46.0	45.6	46.5	46.1	47.0	47.6
Average Growth																				
Nominal	5.30%																			
Real	0.19%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1711.0	1767.3	1810.7	1868.1	1983.0	2069.4	2237.0	2388.4	2580.5	2744.8	2986.4	3123.1	3357.1	3533.0	3808.0	4002.3	4276.5	4565.1
Real	1566.3	1512.0	1549.0	1522.3	1484.0	1456.8	1471.4	1460.9	1502.6	1526.5	1569.2	1588.1	1644.1	1635.9	1673.1	1675.4	1718.1	1718.2	1746.8	1774.2
NPV (9.54% discount rate)	21815.3																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.2	2178.6	2293.1	2411.8	2564.5	2808.5	3018.3	3359.0	3684.2	4082.5	4460.9	4975.3	5332.0	5854.6	6281.9	6872.1	7349.3	7995.4	8689.3
Real	1912.2	1891.7	1972.3	1975.3	1976.6	1999.8	2083.8	2130.8	2256.3	2354.6	2482.5	2581.1	2739.0	2792.9	2917.8	2978.9	3100.6	3155.0	3265.8	3377.0
NPV (9.54% discount rate)	33115.1																			
Average Growth																				
Nominal	8.29%																			
Real	3.04%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.4	51.7	55.1	57.5	61.8	65.4	70.3	74.5	80.6	83.7	89.7	93.6	99.7	103.8	110.7	117.5
Real	45.9	43.4	43.9	42.6	41.3	40.3	40.9	40.6	41.5	41.8	42.8	43.1	44.4	43.9	44.7	44.4	45.0	44.6	45.2	45.7
Average Growth																				
Nominal	5.07%																			
Real	-0.03%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 3 with High Gas

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Small CT (1)				8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	65	85	85	85	85	85
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
New Geothermal (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)						31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CT (1)							20	20	20	20	20	20	20	20	20	20	20	20	20	20
New Geothermal (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)											100	100	100	100	100	100	100	100	100	100
Large CT (2)									31	31	31	31	31	31	31	31	31	31	31	31
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
New Geothermal (4)												100	100	100	100	100	100	100	100	100
Hunter 4 (1)														300	300	300	300	300	300	300
Large CT (4)												31	31	31	31	31	31	31	31	31
Large CT (5)												31	31	31	31	31	31	31	31	31
Large CT (6)												31	31	31	31	31	31	31	31	31
Medium CT (2)												20	20	20	20	20	20	20	20	20
Wyodak 2 (1)																192	192	192	192	192
Large CT													31	31	31	31	31	31	31	31
Small CT (Jul)															4	8	8	8	8	8
Large CC CT																	175	175	175	175
IGCC Coal																		188	188	188
IGCC Coal																			188	188
IGCC Coal																				188
Wind - WP																				52
total	6,697	6,784	7,021	7,139	7,358	7,592	7,821	7,962	8,220	8,393	8,599	8,793	8,926	9,207	9,259	9,443	9,679	9,829	10,020	10,216
Balance	180	179	229	157	150	190	226	189	231	196	172	159	169	307	153	203	230	218	204	180

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PacifiCorp Electric Operations
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Environmental Level 3 with High Gas

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
New Geothermal (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)							100	100	100	100	100	100	100	100	100	100	100	100	100	100
New Geothermal (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)											100	100	100	100	100	100	100	100	100	100
Large CT (2)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (4)												100	100	100	100	100	100	100	100	100
Hunter 4 (1)														400	400	400	400	400	400	400
Large CT (4)												156	156	156	156	156	156	156	156	156
Large CT (5)												156	156	156	156	156	156	156	156	156
Large CT (6)												156	156	156	156	156	156	156	156	156
Medium CT (2)												100	100	100	100	100	100	100	100	100
Wyodak 2 (1)																256	256	256	256	256
Large CT													156	156	156	156	156	156	156	156
Small CT (Jul)																40	40	40	40	40
Large CC CT																	250	250	250	250
IGCC Coal																		250	250	250
IGCC Coal																			250	250
IGCC Coal																				250
Wind - WP																				59
total	9,479	9,865	10,167	10,523	10,797	11,233	11,870	12,137	12,589	12,841	13,053	13,804	14,007	14,489	14,421	14,777	15,025	15,316	15,439	15,805
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,364	1,434	1,477	1,499	1,556	1,581	1,598	1,698	1,722	1,782	1,782	1,826	1,864	1,901	1,939	1,985
Balance	-153	13	77	160	218	336	676	612	753	672	561	904	991	1,227	853	1,073	1,005	985	861	889
(Reserve+Balance)/Requirement	14%	15%	16%	16%	17%	19%	22%	21%	22%	21%	20%	23%	24%	26%	22%	24%	24%	23%	22%	22%

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PacifiCorp Electric Operations
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Environmental Level 3 with High Gas

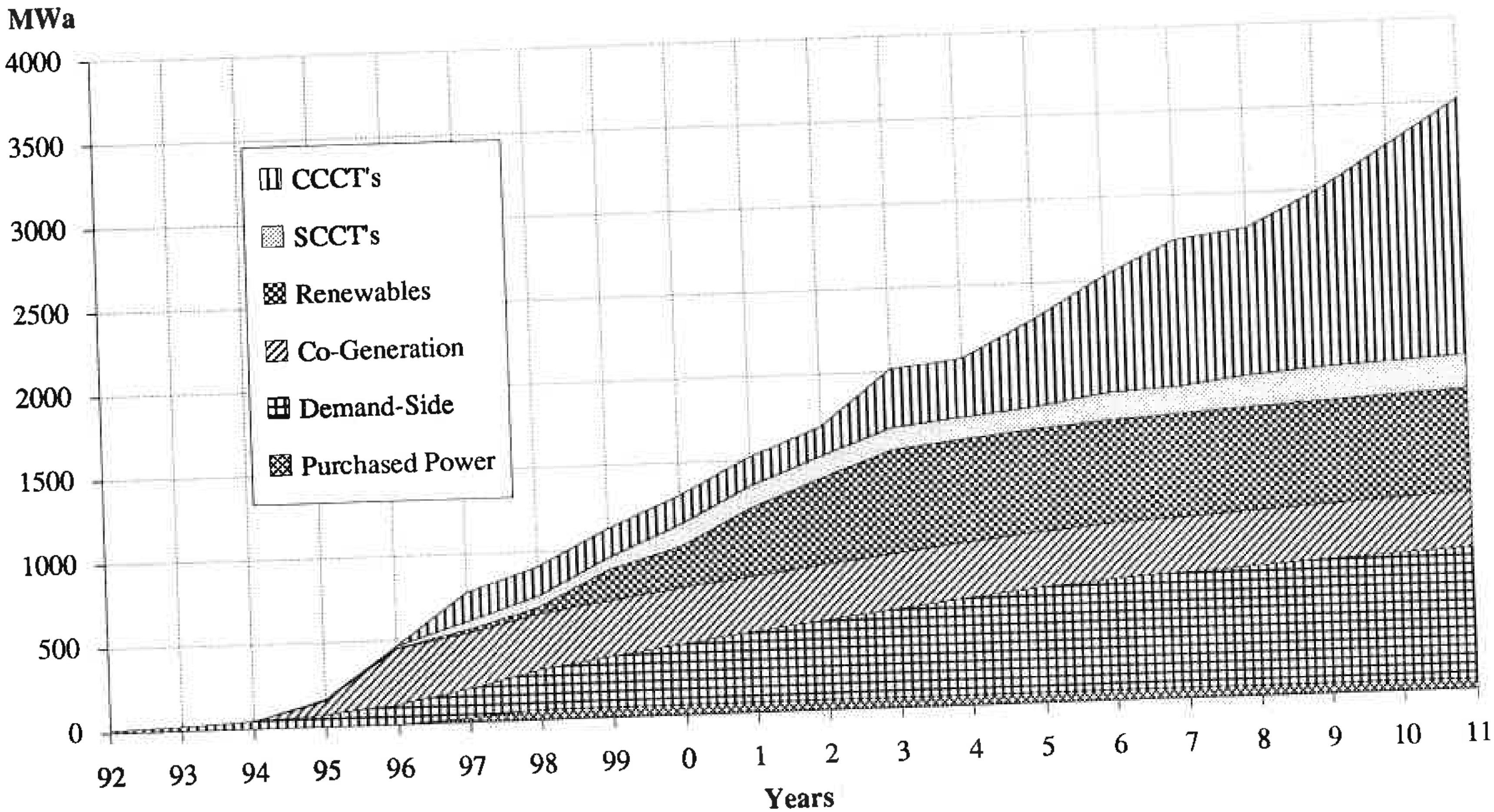
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424
Resources										
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452
BPA Entitlement (1)										
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						10	25	25	35	45
CoGen (1)				94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40
CoGen 1 (1)					100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100
CoGen (2)					94	94	94	94	94	94
Small CT (Jul) (1)					40	40	40	40	40	40
New Geothermal (1)								100	100	100
Large CC CT (1)						250	250	250	250	250
Large CT (1)						156	156	156	156	156
Medium CT (1)							100	100	100	100
New Geothermal (2)										100
New Geothermal (3)										
Large CT (2)									156	156
Large CT (3)									156	156
New Geothermal (4)										
Hunter 4 (1)										
Large CT (4)										
Large CT (5)										
Large CT (6)										
Medium CT (2)										
Wyodak 2 (1)										
Large CT										
Small CT (Jul)										
Large CC CT										
IGCC Coal										
IGCC Coal										
IGCC Coal										
Wind - WP										
total	9,783	9,833	10,154	10,441	10,662	11,032	11,191	11,403	11,866	12,097
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,320	1,364	1,434	1,477	1,499	1,556	1,581
Balance	81	93	176	200	22	117	-11	-4	91	92
(Reserve+Balance)/Requirement	16%	17%	17%	17%	15%	16%	15%	15%	16%	16%

Summer Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources										
Existing Generation	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)										
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	55	55	55	55	55	55	55	55	55	55
CoGen (1)	94	94	94	94	94	94	94	94	94	94
Small CT (1)	40	40	40	40	40	40	40	40	40	40
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
CoGen (2)	94	94	94	94	94	94	94	94	94	94
Small CT (Jul) (1)	40	40	40	40	40	40	40	40	40	40
New Geothermal (1)	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Medium CT (1)	100	100	100	100	100	100	100	100	100	100
New Geothermal (2)	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)	100	100	100	100	100	100	100	100	100	100
Large CT (2)	156	156	156	156	156	156	156	156	156	156
Large CT (3)	156	156	156	156	156	156	156	156	156	156
New Geothermal (4)		100	100	100	100	100	100	100	100	100
Hunter 4 (1)				400	400	400	400	400	400	400
Large CT (4)		156	156	156	156	156	156	156	156	156
Large CT (5)		156	156	156	156	156	156	156	156	156
Large CT (6)		156	156	156	156	156	156	156	156	156
Medium CT (2)		100	100	100	100	100	100	100	100	100
Wyodak 2 (1)						256	256	256	256	256
Large CT			156	156	156	156	156	156	156	156
Small CT (Jul)					40	40	40	40	40	40
Large CC CT							250	250	250	250
IGCC Coal								250	250	250
IGCC Coal									250	250
IGCC Coal										250
Wind - WP										14
total	12,289	12,992	13,221	13,692	13,668	14,014	14,303	14,587	14,719	15,016
Reserve Requirement										
Total Company Reserve	1,598	1,698	1,722	1,782	1,782	1,826	1,864	1,901	1,939	1,985
Balance	-29	278	399	643	310	526	508	564	417	385
(Reserve+Balance)/Requirement	15%	18%	19%	22%	18%	20%	20%	20%	19%	19%

PacifiCorp - RAMPP 2

Illustrative Plan

Environmental Level 4



KEY OUTPUTS
Environmental Level 4

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485
Net Electric Plant (M$)	5945.7	6499.8	6800.8	7114.7	7497.0	8003.4	8768.1	9677.8	10688.5	11814.4
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)										
Nominal	1910.8	1984.0	2169.6	2277.2	2386.0	2525.7	2742.5	2927.0	3240.1	3536.5
Real	1910.8	1887.7	1964.1	1961.5	1955.5	1969.6	2034.9	2066.3	2176.4	2260.2
NPV (9.54% discount rate)	31732.2									
Average Growth										
Nominal	7.82%									
Real	2.59%									
Base Unit Cost (mills/kwh)										
Nominal	45.9	45.7	48.5	49.5	50.5	51.9	55.3	57.8	62.4	66.2
Real	45.9	43.5	43.9	42.6	41.4	40.5	41.0	40.8	41.9	42.3
Average Growth										
Nominal	5.08%									
Real	-0.02%									
Average Customer Bill ($)										
Nominal	1566.3	1589.1	1711.0	1767.3	1810.7	1868.1	1978.5	2064.5	2231.1	2381.8
Real	1566.3	1512.0	1549.0	1522.3	1484.0	1456.8	1467.9	1457.4	1498.7	1522.2
NPV (9.54% discount rate)	21598.9									
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2
NPV (9.54% discount rate)	41.0									
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1
NPV (9.54% discount rate)	976.3									
Total Resource Cost (M$)										
Nominal	1912.2	1988.2	2178.6	2293.1	2411.8	2564.5	2802.1	3011.3	3350.5	3674.3
Real	1912.2	1891.7	1972.3	1975.3	1976.6	1999.8	2079.1	2125.9	2250.6	2348.3
NPV (9.54% discount rate)	32749.4									
Average Growth										
Nominal	8.08%									
Real	2.84%									
Mills / KWh										
Nominal	45.9	45.7	48.5	49.4	50.4	51.7	55.0	57.3	61.6	65.2
Real	45.9	43.4	43.9	42.6	41.3	40.3	40.8	40.5	41.4	41.7
Average Growth										
Nominal	4.86%									
Real	-0.22%									

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	12853.9	13621.9	14230.6	14970.4	15621.9	16218.7	16939.4	17763.9	18402.6	18740.2
Net Conservation Assets	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$) Nominal	3898.8	4242.7	4660.4	4948.2	5363.2	5844.7	6363.5	6806.0	7357.9	7990.3
Real	2370.9	2454.8	2565.6	2591.8	2672.9	2771.5	2871.1	2921.8	3005.4	3105.3
Base Unit Cost (mills/kwh) Nominal	71.3	75.6	81.0	83.8	89.0	94.5	100.3	104.6	110.9	117.7
Real	43.3	43.7	44.6	43.9	44.4	44.8	45.3	44.9	45.3	45.8
Average Customer Bill ($) Nominal	2569.1	2730.9	2932.4	3048.8	3240.8	3468.8	3710.3	3894.3	4125.1	4390.0
Real	1562.2	1580.1	1614.3	1596.9	1615.2	1644.9	1674.0	1671.8	1684.9	1706.1
Customer Cost (M$)	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
Energy Services Charge (M$)	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
Total Resource Cost (M$) Nominal	4065.1	4439.4	4889.4	5211.5	5662.1	6173.8	6704.5	7160.6	7725.2	8370.6
Real	2472.0	2568.6	2691.7	2729.8	2821.9	2927.6	3025.0	3074.0	3155.5	3253.2
Mills / KWh Nominal	70.0	74.1	79.2	81.8	86.8	92.0	97.3	101.2	106.9	113.2
Real	42.6	42.9	43.6	42.9	43.3	43.6	43.9	43.4	43.7	44.0

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Small CT (1)				8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
New Geothermal (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)						31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CT (1)							20	20	20	20	20	20	20	20	20	20	20	20	20	20
New Geothermal (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)											100	100	100	100	100	100	100	100	100	100
Large CT (2)									31	31	31	31	31	31	31	31	31	31	31	31
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
New Geothermal (4)												100	100	100	100	100	100	100	100	100
Large CC CT (2)												175	175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CT															31	31	31	31	31	31
Large CC CT																175	175	175	175	175
Large CT																	31	31	31	31
Large CC CT																		175	175	175
Small CT																		8	8	8
Large CC CT																			175	175
Medium CC CT																			64	64
Large CC CT																				175
Medium CC CT																				64
total	6,697	6,784	7,021	7,139	7,358	7,592	7,821	7,962	8,220	8,393	8,599	8,854	8,956	9,112	9,366	9,529	9,622	9,767	10,009	10,205
Balance	180	179	229	157	150	190	226	189	231	196	172	220	199	212	260	290	173	156	194	169

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 4

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,056	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
New Geothermal (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)							100	100	100	100	100	100	100	100	100	100	100	100	100	100
New Geothermal (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)											100	100	100	100	100	100	100	100	100	100
Large CT (2)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (4)												100	100	100	100	100	100	100	100	100
Large CC CT (2)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CT															156	156	156	156	156	156
Large CC CT																250	250	250	250	250
Large CT																	156	156	156	156
Large CC CT																		250	250	250
Small CT																		40	40	40
Large CC CT																			250	250
Medium CC CT																			128	128
Large CC CT																				250
Medium CC CT																				128
total	9,479	9,865	10,167	10,523	10,797	11,233	11,870	12,137	12,589	12,841	13,053	13,486	13,533	13,865	14,203	14,513	14,667	14,998	15,249	15,683
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,364	1,434	1,477	1,499	1,556	1,581	1,598	1,651	1,651	1,688	1,749	1,786	1,810	1,853	1,910	1,967
Balance	-153	13	77	160	218	336	676	612	753	672	561	633	588	696	667	848	701	715	700	785
(Reserve+Balance)/Requirement	14%	15%	16%	16%	17%	19%	22%	21%	22%	21%	20%	20%	20%	21%	21%	22%	21%	21%	21%	21%

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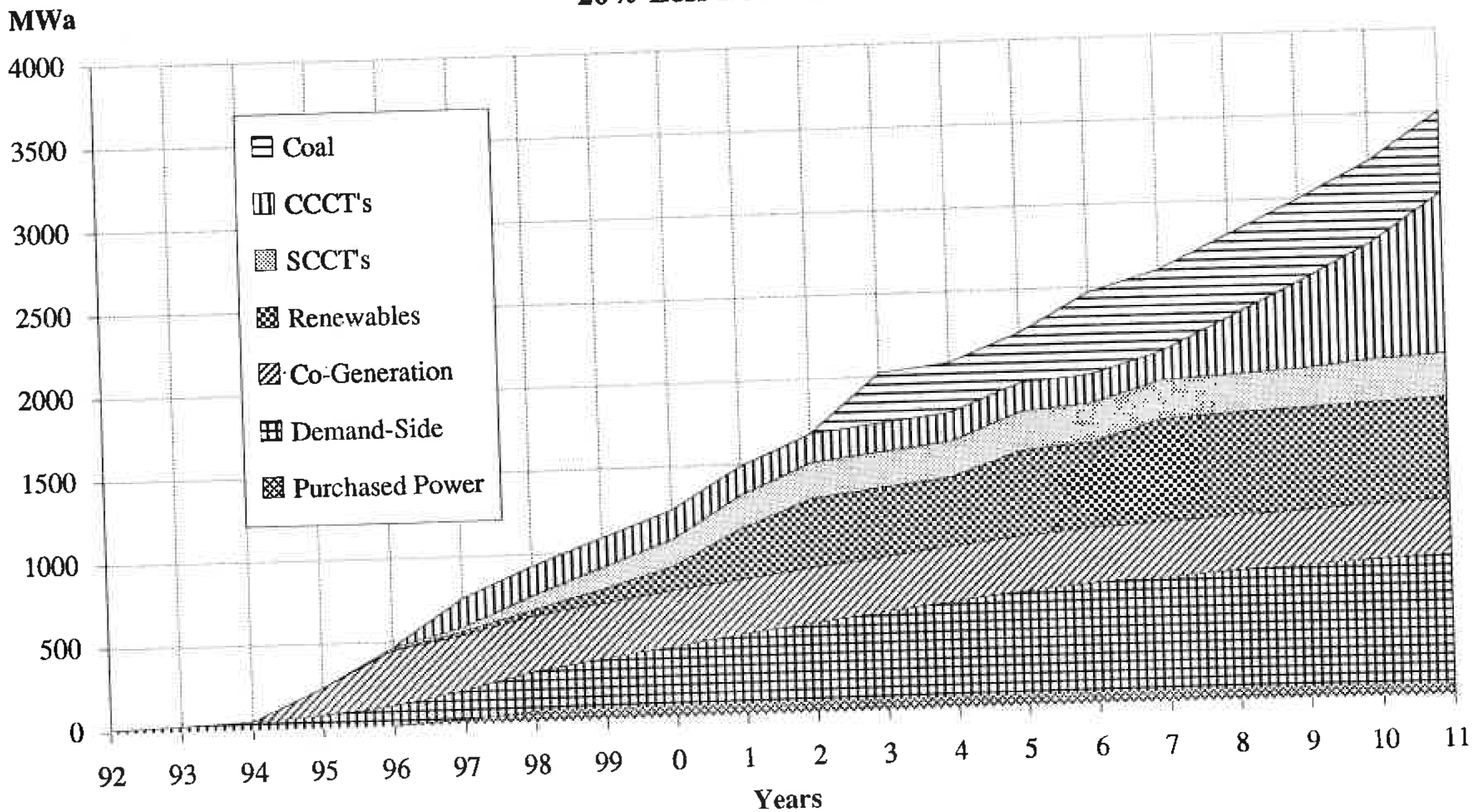
PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Environmental Level 4

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
New Geothermal (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)							100	100	100	100	100	100	100	100	100	100	100	100	100	100
New Geothermal (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)											100	100	100	100	100	100	100	100	100	100
Large CT (2)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (4)												100	100	100	100	100	100	100	100	100
Large CC CT (2)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CT															156	156	156	156	156	156
Large CC CT																250	250	250	250	250
Large CT																	156	156	156	156
Large CC CT																		250	250	250
Small CT																		40	40	40
Large CC CT																			250	250
Medium CC CT																			128	128
Large CC CT																				250
Medium CC CT																				128
total	9,783	9,833	10,154	10,441	10,662	11,032	11,191	11,403	11,866	12,097	12,289	12,674	12,747	13,068	13,410	13,750	13,945	14,269	14,529	14,940
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,364	1,434	1,477	1,499	1,556	1,581	1,598	1,651	1,651	1,688	1,749	1,786	1,810	1,853	1,910	1,967
Balance	81	93	176	200	22	117	-11	-4	91	92	-29	8	-3	112	85	302	204	294	255	327
(Reserve+Balance)/Requirement	16%	17%	17%	17%	15%	16%	15%	15%	16%	16%	15%	15%	15%	16%	16%	18%	17%	18%	18%	18%

PacifiCorp - RAMPP 2

Illustrative Plan

20% Less Renewables Cost



KEY OUTPUTS

Renewables Cost 20% Less

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6789.2	7111.0	7482.5	7983.9	8673.5	9487.9	10705.8	11982.8	12943.6	13736.7	14583.0	15505.4	16385.5	17149.4	17776.6	18577.9	19270.2	19621.0
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.4	2277.2	2377.8	2531.2	2726.0	2940.4	3222.6	3495.8	3879.8	4204.7	4618.0	4904.1	5341.2	5847.4	6353.7	6797.1	7315.6	7917.7
Real	1910.8	1887.7	1964.0	1961.5	1948.8	1973.9	2022.6	2075.8	2164.6	2234.2	2359.3	2432.8	2542.3	2568.8	2662.0	2772.8	2866.7	2917.9	2988.2	3077.1
NPV (9.54% discount rate)	31621.0																			
Average Growth																				
Nominal	7.77%																			
Real	2.54%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.3	52.0	55.0	58.1	62.0	65.4	70.9	74.9	80.2	83.0	88.6	94.5	100.2	104.4	110.3	116.7
Real	45.9	43.5	43.9	42.6	41.2	40.6	40.8	41.0	41.7	41.8	43.1	43.3	44.2	43.5	44.2	44.8	45.2	44.8	45.0	45.3
Average Growth																				
Nominal	5.03%																			
Real	-0.07%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1710.9	1767.3	1804.5	1872.2	1966.5	2073.9	2219.1	2354.4	2556.5	2706.4	2905.7	3021.7	3227.5	3470.5	3704.5	3889.2	4101.4	4350.1
Real	1566.3	1512.0	1548.9	1522.3	1479.0	1460.0	1459.1	1464.1	1490.6	1504.7	1554.6	1565.9	1599.6	1582.7	1608.5	1645.7	1671.4	1669.6	1675.3	1690.6
NPV (9.54% discount rate)	21528.6																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.1	2178.4	2293.1	2403.7	2570.0	2785.6	3024.7	3333.0	3633.7	4046.0	4401.4	4847.0	5167.4	5640.1	6176.5	6694.7	7151.6	7683.0	8298.0
Real	1912.2	1891.7	1972.1	1975.2	1970.0	2004.1	2066.8	2135.3	2238.8	2322.3	2460.4	2546.6	2668.3	2706.7	2810.9	2928.9	3020.6	3070.1	3138.2	3224.9
NPV (9.54% discount rate)	32638.3																			
Average Growth																				
Nominal	8.03%																			
Real	2.79%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.2	51.8	54.6	57.6	61.3	64.5	69.7	73.5	78.5	81.1	86.5	92.0	97.2	101.0	106.4	112.2
Real	45.9	43.4	43.9	42.6	41.1	40.4	40.5	40.7	41.2	41.2	42.4	42.5	43.2	42.5	43.1	43.6	43.8	43.4	43.4	43.6
Average Growth																				
Nominal	4.82%																			
Real	-0.27%																			

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Renewables cost 20% less

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Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
New Geothermal (1)										100	100	100	100	100	100	100	100	100	100	100
Small CT (1)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (2)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (3)								8	8	8	8	8	8	8	8	8	8	8	8	8
Medium CT (1)								20	20	20	20	20	20	20	20	20	20	20	20	20
New Geothermal (2)											100	100	100	100	100	100	100	100	100	100
Hunter 4 (1)												300	300	300	300	300	300	300	300	300
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (1)										16	31	31	31	31	31	31	31	31	31	31
Medium CT (2)										20	20	20	20	20	20	20	20	20	20	20
New Geothermal (3)														100	100	100	100	100	100	100
Wyodak 2 (1)															192	192	192	192	192	192
Medium CT														20	20	20	20	20	20	20
New Geothermal																100	100	100	100	100
Large CC CT																	175	175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Small CT (Jul)																			4	8
Medium CT																			20	20
Large CC CT																				175
Large CC CT (Jul)																				88
total	6,697	6,784	7,021	7,211	7,358	7,569	7,840	7,925	8,152	8,360	8,582	8,862	8,964	9,065	9,305	9,393	9,630	9,767	9,969	10,193
Balance	180	179	229	229	150	167	245	152	163	164	156	228	207	165	199	154	181	156	153	157

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Renewables cost 20% less

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (1)										100	100	100	100	100	100	100	100	100	100	100
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
New Geothermal (2)											100	100	100	100	100	100	100	100	100	100
Hunter 4 (1)												400	400	400	400	400	400	400	400	400
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)											156	156	156	156	156	156	156	156	156	156
Medium CT (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)														100	100	100	100	100	100	100
Wyodak 2 (1)															256	256	256	256	256	256
Medium CT														100	100	100	100	100	100	100
New Geothermal																100	100	100	100	100
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Small CT (Jul)																				40
Medium CT																			100	100
Large CC CT																				250
Large CC CT (Jul)																				
total	9,479	9,865	10,167	10,577	10,757	11,117	11,966	12,353	12,649	13,001	13,369	13,852	13,899	14,181	14,369	14,529	14,777	15,068	15,291	15,637
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,565	1,605	1,645	1,705	1,705	1,735	1,774	1,789	1,826	1,864	1,916	1,960
Balance	-153	13	77	206	184	237	758	796	804	808	830	944	899	965	809	862	794	774	736	746
(Reserve+Balance)/Requirement	14%	15%	16%	17%	17%	17%	23%	23%	23%	23%	23%	24%	23%	24%	22%	22%	22%	21%	21%	21%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Renewables cost 20% less

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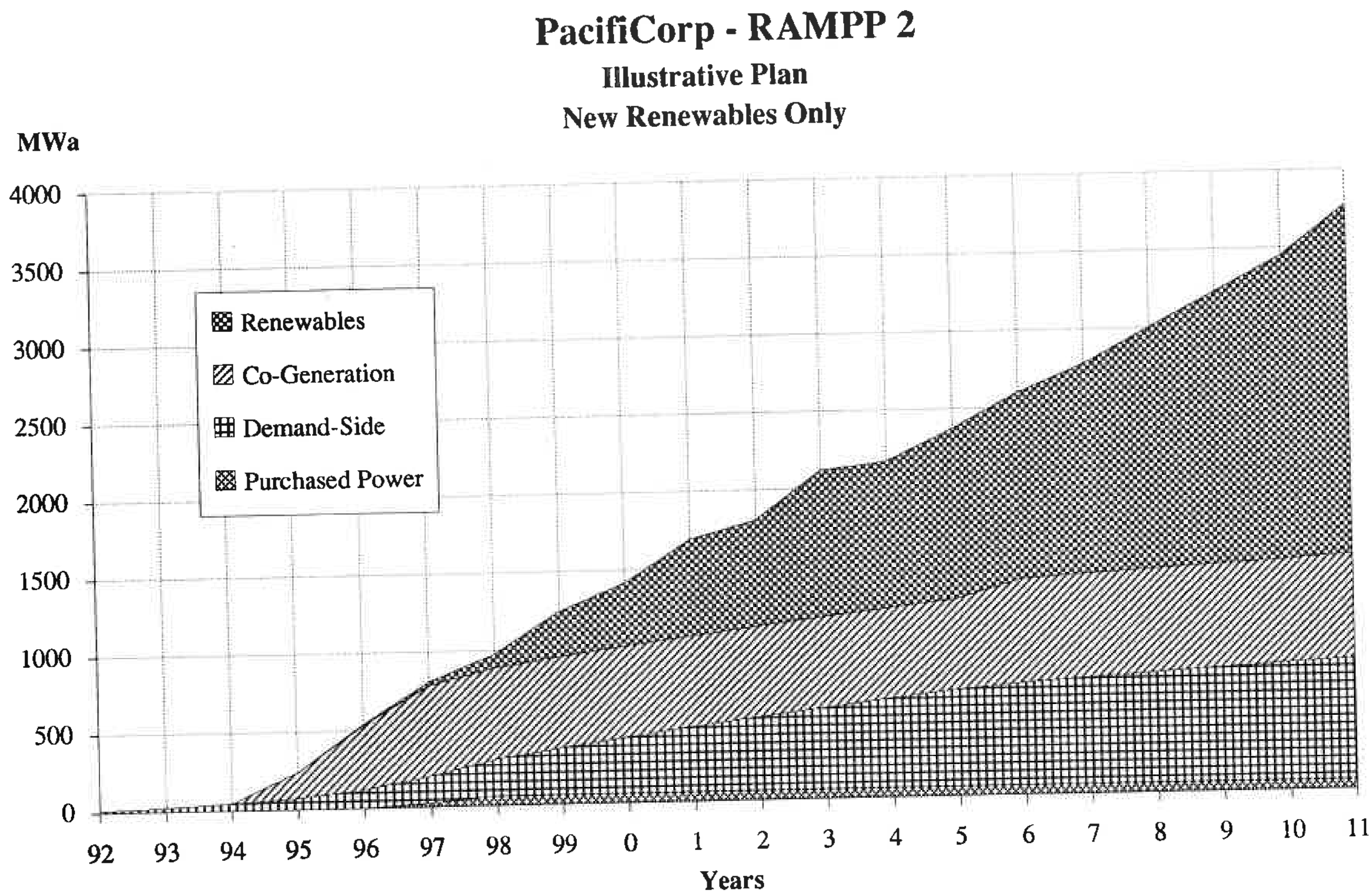
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
New Geothermal (1)										100	100	100	100	100	100	100	100	100	100	100
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
New Geothermal (2)											100	100	100	100	100	100	100	100	100	100
Hunter 4 (1)												400	400	400	400	400	400	400	400	400
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)										156	156	156	156	156	156	156	156	156	156	156
Medium CT (2)										100	100	100	100	100	100	100	100	100	100	100
New Geothermal (3)														100	100	100	100	100	100	100
Wyodak 2 (1)															256	256	256	256	256	256
Medium CT														100	100	100	100	100	100	100
New Geothermal																100	100	100	100	100
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Small CT (Jul)																			40	40
Medium CT																			100	100
Large CC CT																				250
Large CC CT (Jul)																				250
total	9,783	9,833	10,154	10,495	10,702	10,916	11,287	11,619	11,926	12,413	12,605	13,040	13,113	13,384	13,576	13,768	14,055	14,339	14,611	15,144
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,416	1,491	1,532	1,565	1,605	1,645	1,705	1,705	1,735	1,774	1,789	1,826	1,864	1,916	1,960
Balance	81	93	176	246	68	19	71	179	142	384	239	319	308	381	226	316	297	353	331	538
(Reserve+Balance)/Requirement	16%	17%	17%	18%	15%	15%	16%	17%	17%	19%	18%	18%	18%	19%	17%	18%	18%	18%	18%	20%


PacifiCorp - RAMPP 2
Illustrative Plan
New Renewables Only
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS
New Renewables Only

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6759.7	6960.8	7179.0	7654.3	8620.4	9588.9	10783.6	11709.5	12758.6	14203.4	14251.9	15405.1	17138.4	18116.3	19569.1	21174.3	23351.2	23888.0
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.0	2275.0	2373.4	2527.1	2852.6	3236.3	3348.9	3961.6	4095.1	4741.1	5313.6	5259.6	5774.6	6917.3	6924.0	7470.9	8084.5	9210.8
Real	1910.8	1887.7	1963.6	1959.6	1945.2	1970.6	2116.5	2284.7	2249.5	2531.9	2490.2	2743.1	2925.2	2755.0	2878.0	3280.2	3124.0	3207.2	3302.2	3579.7
NPV (9.54% discount rate)	33782.1																			
Average Growth																				
Nominal	8.63%																			
Real	3.36%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.4	50.2	51.9	57.5	63.9	64.5	74.1	74.8	84.5	92.3	89.0	95.8	111.8	109.2	114.8	121.8	135.7
Real	45.9	43.5	43.9	42.6	41.2	40.5	42.7	45.1	43.3	47.4	45.5	48.9	50.8	46.6	47.8	53.0	49.3	49.3	49.8	52.7
Average Growth																				
Nominal	5.87%																			
Real	0.73%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1710.6	1765.6	1801.2	1869.1	2057.9	2282.7	2306.1	2668.1	2698.4	3051.7	3343.4	3240.7	3489.4	4105.5	4037.1	4274.7	4532.4	5060.6
Real	1566.3	1512.0	1548.6	1520.8	1476.2	1457.6	1526.9	1611.5	1549.0	1705.2	1640.9	1765.7	1840.6	1697.5	1739.1	1946.8	1821.5	1835.1	1851.3	1966.8
NPV (9.54% discount rate)	22867.2																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.1	2178.0	2290.9	2399.3	2565.8	2912.2	3320.6	3459.4	4099.5	4261.4	4937.8	5542.6	5522.9	6073.5	7246.4	7265.0	7825.4	8451.8	9591.2
Real	1912.2	1891.7	1971.7	1973.3	1966.4	2000.8	2160.8	2344.2	2323.7	2620.0	2591.4	2856.9	3051.3	2892.9	3026.9	3436.2	3277.9	3359.4	3452.2	3727.5
NPV (9.54% discount rate)	34799.3																			
Average Growth																				
Nominal	8.86%																			
Real	3.58%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.1	51.7	57.1	63.2	63.6	72.7	73.4	82.4	89.8	86.7	93.1	107.9	105.4	110.6	117.0	129.7
Real	45.9	43.4	43.9	42.5	41.1	40.3	42.4	44.6	42.7	46.5	44.6	47.7	49.4	45.4	46.4	51.2	47.6	47.5	47.8	50.4
Average Growth																				
Nominal	5.62%																			
Real	0.49%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
New Renewables only

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Mod. Pumped Storage (1)						-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 2 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 2 (2)						85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 2 (3)						85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Mod. Pumped Storage (-1)							-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13
Mod. Pumped Storage (-2)							-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13
Wind - NS (1)							52	52	52	52	52	52	52	52	52	52	52	52	52	52
Wind - NS (7)								52	52	52	52	52	52	52	52	52	52	52	52	52
Wind - NS (8)								52	52	52	52	52	52	52	52	52	52	52	52	52
Wind - NS (9)								52	52	52	52	52	52	52	52	52	52	52	52	52
Mod. Pumped Storage (-3)									-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13
Mod. Pumped Storage (-4)									-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13
Wind - NS (10)									52	52	52	52	52	52	52	52	52	52	52	52
Mod. Pumped Storage (2)											-13	-13	-13	-13	-13	-13	-13	-13	-13	-13
Mod. Pumped Storage (3)											-13	-13	-13	-13	-13	-13	-13	-13	-13	-13
Wind - NS (17)										52	52	52	52	52	52	52	52	52	52	52
Wind - NS (18)										52	52	52	52	52	52	52	52	52	52	52
Wind - NS (19)										52	52	52	52	52	52	52	52	52	52	52
Mod. Pumped Storage (4)												-13	-13	-13	-13	-13	-13	-13	-13	-13
Mod. Pumped Storage (5)												-13	-13	-13	-13	-13	-13	-13	-13	-13
Wind - NS (-1)												52	52	52	52	52	52	52	52	52
Wind - NS (-2)												52	52	52	52	52	52	52	52	52
Wind - NS (-3)												52	52	52	52	52	52	52	52	52
Wind - NS (-4)												52	52	52	52	52	52	52	52	52
Wind - NS (-5)												52	52	52	52	52	52	52	52	52
Wind - NS (20)											52	52	52	52	52	52	52	52	52	52
Wind - NS (-6)														52	52	52	52	52	52	52
Wind - NS (-7)														52	52	52	52	52	52	52
Wind - NS (-8)														52	52	52	52	52	52	52
Mod. Pumped Storage															-13	-13	-13	-13	-13	-13
Mod. Pumped Storage															-13	-13	-13	-13	-13	-13
Mod. Pumped Storage															-13	-13	-13	-13	-13	-13
CoGen 2															85	85	85	85	85	85
Wind - NS (-9)															52	52	52	52	52	52
Wind - NS (-10)															52	52	52	52	52	52
New Geothermal																100	100	100	100	100
Wind - NS (-11)																52	52	52	52	52
New Geothermal																	100	100	100	100
New Geothermal																	100	100	100	100
New Geothermal																		100	100	100
New Geothermal																		100	100	100
Mod. Pumped Storage																			-13	-13
Mod. Pumped Storage																			-13	-13
New Geothermal																			100	100
New Geothermal																			100	100
New Geothermal																				100
New Geothermal																				100
New Geothermal																				100
total	6,697	6,784	7,021	7,211	7,431	7,612	7,846	8,043	8,263	8,492	8,624	8,838	8,940	9,076	9,273	9,413	9,675	9,837	10,014	10,270
Balance	180	179	229	229	223	210	251	269	274	296	197	203	183	176	167	174	226	226	198	234

Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Mod. Pumped Storage (1)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (2)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (3)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (-1)							100	100	100	100	100	100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (-2)							100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wind - NS (1)							30	30	30	30	30	30	30	30	30	30	30	30	30	30
Wind - NS (7)								30	30	30	30	30	30	30	30	30	30	30	30	30
Wind - NS (8)								30	30	30	30	30	30	30	30	30	30	30	30	30
Wind - NS (9)								30	30	30	30	30	30	30	30	30	30	30	30	30
Mod. Pumped Storage (-3)									100	100	100	100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (-4)									100	100	100	100	100	100	100	100	100	100	100	100
Wind - NS (10)									30	30	30	30	30	30	30	30	30	30	30	30
Mod. Pumped Storage (2)											100	100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (3)											100	100	100	100	100	100	100	100	100	100
Wind - NS (17)										30	30	30	30	30	30	30	30	30	30	30
Wind - NS (18)										30	30	30	30	30	30	30	30	30	30	30
Wind - NS (19)										30	30	30	30	30	30	30	30	30	30	30
Mod. Pumped Storage (4)												100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (5)												100	100	100	100	100	100	100	100	100
Wind - NS (-1)												30	30	30	30	30	30	30	30	30
Wind - NS (-2)												30	30	30	30	30	30	30	30	30
Wind - NS (-3)												30	30	30	30	30	30	30	30	30
Wind - NS (-4)												30	30	30	30	30	30	30	30	30
Wind - NS (-5)												30	30	30	30	30	30	30	30	30
Wind - NS (20)											30	30	30	30	30	30	30	30	30	30
Wind - NS (-6)														30	30	30	30	30	30	30
Wind - NS (-7)														30	30	30	30	30	30	30
Wind - NS (-8)														30	30	30	30	30	30	30
Mod. Pumped Storage															100	100	100	100	100	100
Mod. Pumped Storage															100	100	100	100	100	100
Mod. Pumped Storage															100	100	100	100	100	100
CoGen 2															100	100	100	100	100	100
Wind - NS (-9)															30	30	30	30	30	30
Wind - NS (-10)															30	30	30	30	30	30
New Geothermal																100	100	100	100	100
Wind - NS (-11)																30	30	30	30	30
New Geothermal																	100	100	100	100
New Geothermal																	100	100	100	100
New Geothermal																		100	100	100
New Geothermal																		100	100	100
Mod. Pumped Storage																			100	100
Mod. Pumped Storage																			100	100
New Geothermal																			100	100
New Geothermal																			100	100
New Geothermal																				100
New Geothermal																				100
New Geothermal																				100
total	9,479	9,865	10,167	10,577	10,857	11,147	11,914	12,171	12,541	12,783	13,125	13,558	13,605	13,777	14,169	14,359	14,557	14,798	15,071	15,427
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,373	1,421	1,476	1,497	1,538	1,561	1,598	1,658	1,658	1,673	1,733	1,748	1,778	1,808	1,868	1,913
Balance	-153	13	77	206	269	262	721	648	722	633	633	697	652	623	649	732	622	560	564	583
(Reserve+Balance)/Requirement	14%	15%	16%	17%	18%	18%	23%	21%	22%	21%	20%	21%	20%	20%	20%	21%	20%	19%	19%	19%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
New Renewables only

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Mod. Pumped Storage (1)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (2)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (3)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (-1)							100	100	100	100	100	100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (-2)							100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wind - NS (1)							30	30	30	30	30	30	30	30	30	30	30	30	30	30
Wind - NS (7)								30	30	30	30	30	30	30	30	30	30	30	30	30
Wind - NS (8)								30	30	30	30	30	30	30	30	30	30	30	30	30
Wind - NS (9)								30	30	30	30	30	30	30	30	30	30	30	30	30
Mod. Pumped Storage (-3)									100	100	100	100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (-4)									100	100	100	100	100	100	100	100	100	100	100	100
Wind - NS (10)									30	30	30	30	30	30	30	30	30	30	30	30
Mod. Pumped Storage (2)											100	100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (3)											100	100	100	100	100	100	100	100	100	100
Wind - NS (17)										30	30	30	30	30	30	30	30	30	30	30
Wind - NS (18)										30	30	30	30	30	30	30	30	30	30	30
Wind - NS (19)										30	30	30	30	30	30	30	30	30	30	30
Mod. Pumped Storage (4)												100	100	100	100	100	100	100	100	100
Mod. Pumped Storage (5)												100	100	100	100	100	100	100	100	100
Wind - NS (-1)												30	30	30	30	30	30	30	30	30
Wind - NS (-2)												30	30	30	30	30	30	30	30	30
Wind - NS (-3)												30	30	30	30	30	30	30	30	30
Wind - NS (-4)												30	30	30	30	30	30	30	30	30
Wind - NS (-5)												30	30	30	30	30	30	30	30	30
Wind - NS (20)											30	30	30	30	30	30	30	30	30	30
Wind - NS (-6)														30	30	30	30	30	30	30
Wind - NS (-7)														30	30	30	30	30	30	30
Wind - NS (-8)														30	30	30	30	30	30	30
Mod. Pumped Storage															100	100	100	100	100	100
Mod. Pumped Storage															100	100	100	100	100	100
Mod. Pumped Storage															100	100	100	100	100	100
CoGen 2															100	100	100	100	100	100
Wind - NS (-9)															30	30	30	30	30	30
Wind - NS (-10)															30	30	30	30	30	30
New Geothermal																100	100	100	100	100
Wind - NS (-11)																30	30	30	30	30
New Geothermal																	100	100	100	100
New Geothermal																	100	100	100	100
New Geothermal																		100	100	100
New Geothermal																		100	100	100
Mod. Pumped Storage																			100	100
Mod. Pumped Storage																			100	100
New Geothermal																			100	100
New Geothermal																			100	100
New Geothermal																				100
New Geothermal																				100
New Geothermal																				100
total	9,783	9,833	10,154	10,495	10,682	10,946	11,235	11,437	11,818	12,039	12,361	12,746	12,819	12,980	13,376	13,596	13,835	14,069	14,351	14,684
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,373	1,421	1,476	1,497	1,538	1,561	1,598	1,656	1,658	1,673	1,733	1,748	1,778	1,808	1,868	1,913
Balance	81	93	176	246	33	44	34	32	61	53	42	72	61	39	66	186	125	139	119	124
(Reserve+Balance)/Requirement	16%	17%	17%	18%	15%	15%	16%	15%	16%	15%	15%	16%	15%	15%	16%	17%	16%	16%	16%	16%

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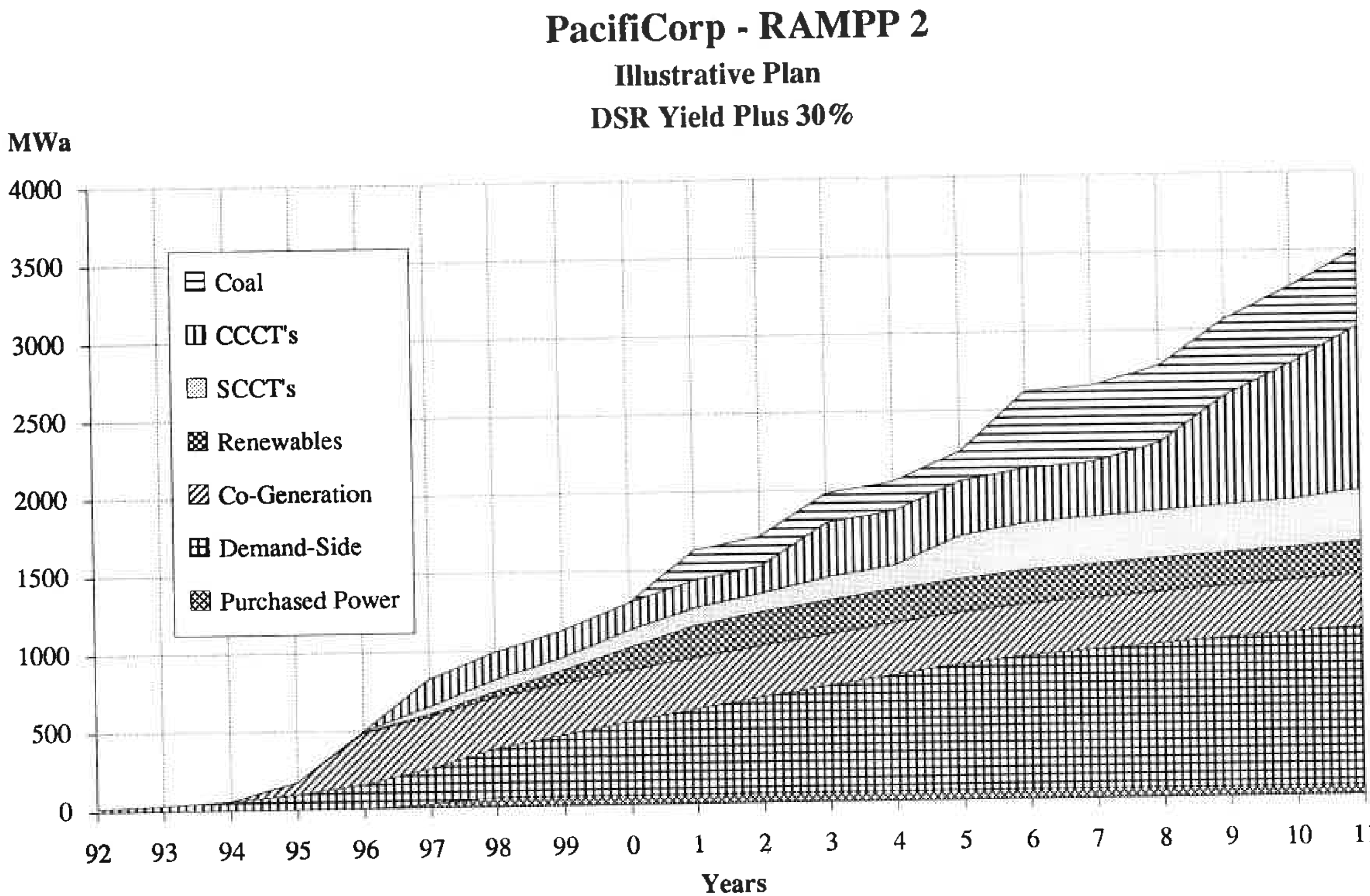

PacifiCorp - RAMPP 2
Illustrative Plan
DSR Yield Plus 30%
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
Coal
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

DSR Yield Plus 30%

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	17.3	34.3	59.9	98.1	155.7	226.1	307.8	389.9	469.3	543.4	613.6	681.3	747.7	809.1	856.9	890.0	923.2	954.7	985.5
System Load net of Conservation	5195.5	5405.7	5575.7	5732.1	5879.9	6024.3	6139.9	6249.2	6398.1	6548.7	6706.6	6866.4	7029.7	7183.3	7336.9	7527.1	7714.0	7890.8	8065.3	8247.6
Energy Sales after Conservation	4749.7	4941.9	5097.3	5240.3	5375.4	5507.4	5613.1	5713.0	5849.1	5986.8	6131.2	6277.3	6426.5	6567.0	6707.4	6881.3	7052.1	7213.8	7373.3	7539.9
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6786.4	7103.0	7502.6	8027.4	8740.3	9554.6	10460.5	11242.1	11940.4	12772.3	13844.0	14911.7	15618.0	16165.7	16762.0	17382.2	17997.6	18413.6
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.6	1983.3	2168.1	2274.5	2375.8	2519.0	2730.8	2916.9	3149.7	3410.3	3801.3	4058.6	4427.4	4717.2	5234.5	5737.2	6185.9	6645.6	7151.4	7720.4
Real	1910.6	1887.1	1962.8	1959.2	1947.2	1964.4	2026.1	2059.2	2115.6	2179.6	2311.6	2348.3	2437.3	2470.9	2608.8	2720.6	2791.0	2852.9	2921.1	3000.5
NPV (9.54% discount rate)	31123.4																			
Average Growth																				
Nominal	7.63%																			
Real	2.40%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.6	49.5	50.5	52.1	55.5	58.3	61.5	64.8	70.8	73.8	78.6	81.8	89.1	95.2	100.1	104.9	110.7	116.9
Real	45.9	43.5	44.0	42.7	41.4	40.6	41.2	41.1	41.3	41.4	43.0	42.7	43.3	42.8	44.4	45.1	45.2	45.0	45.2	45.4
Average Growth																				
Nominal	5.04%																			
Real	-0.06%																			
Average Customer Bill ($)																				
Nominal	1566.1	1588.6	1709.9	1765.2	1803.0	1863.2	1970.0	2057.4	2168.9	2296.8	2504.8	2612.4	2785.7	2906.5	3163.0	3405.1	3606.7	3802.5	4009.3	4241.7
Real	1566.1	1511.5	1547.9	1520.5	1477.7	1452.9	1461.6	1452.4	1456.9	1467.9	1523.2	1511.5	1533.6	1522.4	1576.4	1614.7	1627.3	1632.4	1637.7	1648.5
NPV (9.54% discount rate)	21218.8																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.0	1987.5	2177.1	2290.4	2401.7	2557.8	2790.4	3001.2	3260.1	3548.2	3967.6	4255.3	4656.4	4980.5	5533.4	6066.3	6527.0	7000.2	7518.8	8100.7
Real	1912.0	1891.0	1970.9	1972.9	1968.3	1994.6	2070.3	2118.7	2189.8	2267.7	2412.7	2462.1	2563.4	2608.8	2757.7	2876.6	2944.9	3005.1	3071.1	3148.3
NPV (9.54% discount rate)	32140.7																			
Average Growth																				
Nominal	7.90%																			
Real	2.66%																			
Mills / KWh																				
Nominal	45.9	45.6	48.5	49.4	50.2	51.5	54.7	57.2	60.0	63.0	68.3	71.0	75.4	78.2	84.8	90.4	94.7	98.9	104.1	109.6
Real	45.9	43.4	43.9	42.5	41.1	40.2	40.6	40.3	40.3	40.2	41.6	41.1	41.5	41.0	42.3	42.8	42.7	42.5	42.5	42.6
Average Growth																				
Nominal	4.68%																			
Real	-0.40%																			

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
DSR yield plus 30%

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	4	9	16	28	43	57	71	87	102	117	132	147	161	174	187	200	212	225	238	251
D.S. Options (1)	13	25	43	70	113	169	236	303	367	426	482	535	587	635	670	690	711	729	747	764
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)						31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Wyodak 2 (1)										192	192	192	192	192	192	192	192	192	192	192
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
Small CT (Jul) (3)										4	8	8	8	8	8	8	8	8	8	8
Small CT (1)												8	8	8	8	8	8	8	8	8
Small CT (2)												8	8	8	8	8	8	8	8	8
Small CT (Jul) (4)												4	8	8	8	8	8	8	8	8
Small CT (3)												8	8	8	8	8	8	8	8	8
Hunter 4 (1)															300	300	300	300	300	300
Large CC CT (2)												175	175	175	175	175	175	175	175	175
Large CT														31	31	31	31	31	31	31
Large CT														31	31	31	31	31	31	31
Large CT (Jul)														16	31	31	31	31	31	31
Large CT (Jul)														16	31	31	31	31	31	31
Large CT														31	31	31	31	31	31	31
Large CC CT (Jul)																	88	175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Large CC CT																				175
Small CT																				8
Medium CT (Jul)																				10
Medium CT (Jul)																				10
total	6,701	6,792	7,035	7,154	7,390	7,644	7,904	7,963	8,208	8,494	8,620	8,819	8,941	9,061	9,451	9,446	9,603	9,835	10,020	10,187
Balance	184	187	243	172	182	243	308	190	219	298	194	185	184	161	345	207	154	224	205	151

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
DSR yield plus 30%

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	6	12	23	39	60	81	101	124	147	169	192	214	236	257	278	298	319	340	361	383
D.S. Options (1)	15	31	57	97	169	265	383	498	609	709	801	889	976	1,055	1,113	1,148	1,181	1,212	1,242	1,270
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Small CT (Jul) (3)											40	40	40	40	40	40	40	40	40	40
Small CT (1)												40	40	40	40	40	40	40	40	40
Small CT (2)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (4)													40	40	40	40	40	40	40	40
Small CT (3)												40	40	40	40	40	40	40	40	40
Hunter 4 (1)															400	400	400	400	400	400
Large CC CT (2)												250	250	250	250	250	250	250	250	250
Large CT														156	156	156	156	156	156	156
Large CT														156	156	156	156	156	156	156
Large CT (Jul)															156	156	156	156	156	156
Large CT (Jul)															156	156	156	156	156	156
Large CT														156	156	156	156	156	156	156
Large CC CT (Jul)																		250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Small CT																				40
Medium CT (Jul)																				
Medium CT (Jul)																				
total	9,484	9,875	10,186	10,514	10,810	11,313	12,038	12,237	12,563	12,999	13,178	13,656	13,768	14,342	15,004	15,076	15,087	15,640	15,775	16,133
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,314	1,358	1,434	1,485	1,493	1,526	1,574	1,582	1,638	1,644	1,714	1,821	1,821	1,821	1,896	1,933	1,977
Balance	-148	23	96	157	237	415	835	718	757	837	702	816	831	1,147	1,396	1,377	1,110	1,314	1,202	1,225
(Reserve+Balance)/Requirement	14%	15%	16%	16%	17%	20%	24%	22%	22%	23%	21%	22%	22%	25%	27%	27%	24%	26%	25%	25%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
DSR yield plus 30%

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	4	9	16	28	42	56	70	85	100	115	130	145	159	173	187	201	215	228	242	256
D.S. Options (1)	12	25	45	76	136	217	314	409	501	587	670	750	829	901	955	986	1,016	1,045	1,072	1,098
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Small CT (Jul) (3)										40	40	40	40	40	40	40	40	40	40	40
Small CT (1)												40	40	40	40	40	40	40	40	40
Small CT (2)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (4)												40	40	40	40	40	40	40	40	40
Small CT (3)												40	40	40	40	40	40	40	40	40
Hunter 4 (1)															400	400	400	400	400	400
Large CC CT (2)												250	250	250	250	250	250	250	250	250
Large CT														156	156	156	156	156	156	156
Large CT														156	156	156	156	156	156	156
Large CT (Jul)														156	156	156	156	156	156	156
Large CT (Jul)														156	156	156	156	156	156	156
Large CT														156	156	156	156	156	156	156
Large CC CT (Jul)																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Small CT																				40
Medium CT (Jul)																				100
Medium CT (Jul)																				100
total	9,787	9,840	10,168	10,425	10,703	11,095	11,335	11,473	11,805	12,255	12,369	12,837	12,931	13,802	14,154	14,253	14,553	14,847	14,988	15,520
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,314	1,358	1,434	1,485	1,493	1,526	1,574	1,582	1,638	1,644	1,714	1,821	1,821	1,821	1,896	1,933	1,977
Balance	85	100	190	190	69	180	125	72	60	257	67	183	187	820	756	771	801	829	691	897
(Reserve+Balance)/Requirement	16%	17%	17%	17%	15%	17%	17%	16%	16%	18%	15%	17%	16%	22%	22%	22%	22%	22%	21%	23%

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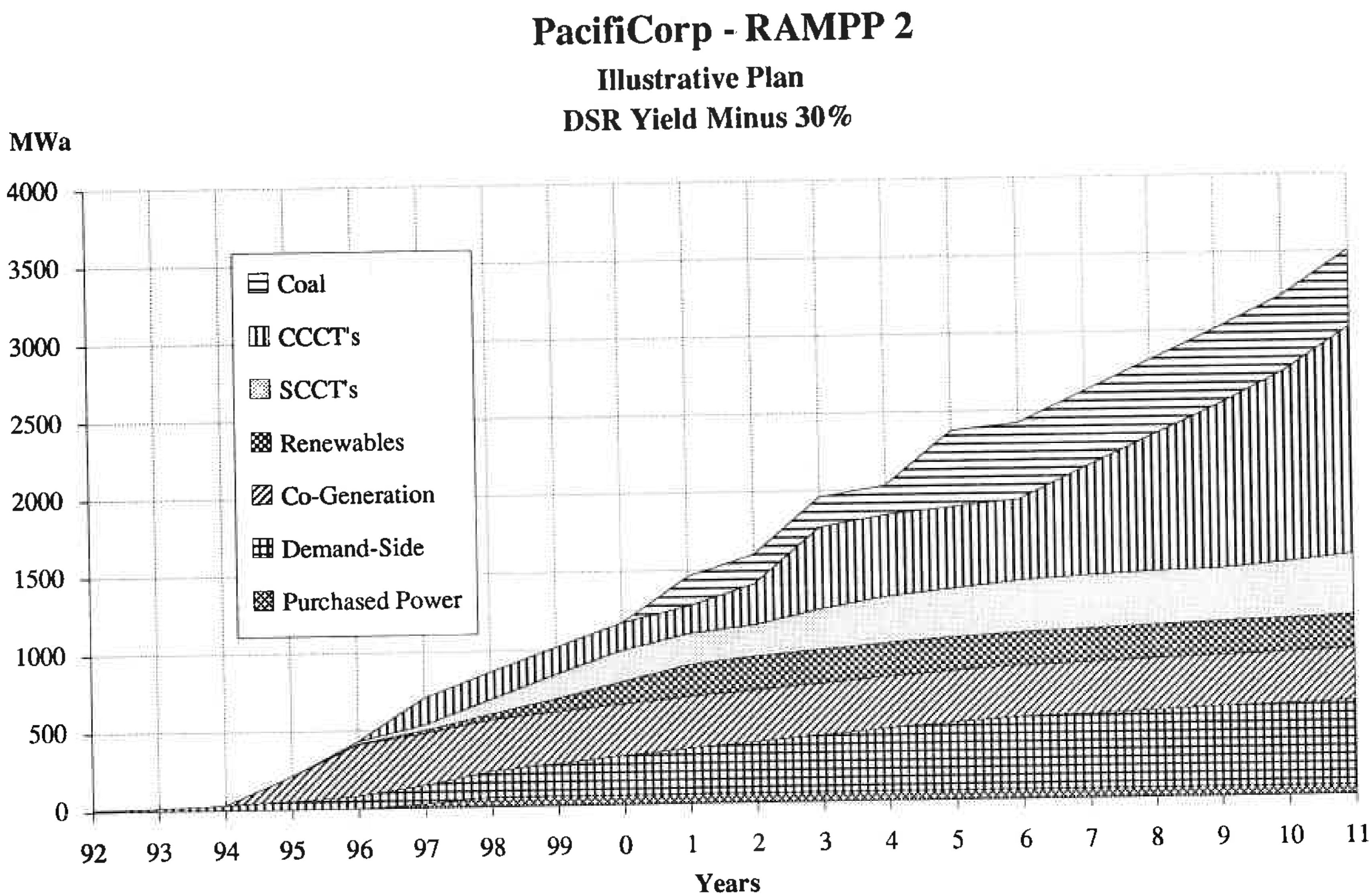
PacifiCorp - RAMPP 2
Illustrative Plan
DSR Yield Minus 30%
MWa
4000
3500
3000
2500
2000
1500
1000
500
0
Coal
CCCT's
SCCT's
Renewables
Co-Generation
Demand-Side
Purchased Power
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

DSR yield minus 30%

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	9.3	18.5	32.3	52.8	83.8	121.8	165.8	210.0	252.7	292.6	330.4	366.9	402.6	435.7	461.4	479.2	497.1	514.1	530.6
System Load net of Conservation	5195.5	5413.7	5591.5	5759.8	5925.2	6096.2	6244.2	6391.3	6578.1	6765.3	6957.4	7149.6	7344.1	7528.4	7710.4	7922.6	8124.8	8316.9	8505.9	8702.4
Energy Sales after Conservation	4749.7	4949.2	5111.8	5265.6	5416.8	5573.1	5708.5	5842.9	6013.7	6184.8	6360.5	6536.2	6714.0	6882.4	7048.8	7242.8	7427.7	7603.3	7776.1	7955.7
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6792.0	7128.7	7512.8	8072.7	8975.7	9932.3	10903.0	11868.7	12879.8	13851.8	14662.1	15427.0	16081.2	16711.1	17338.2	18136.1	18858.1	19232.3
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1911.1	1984.6	2170.7	2280.0	2382.4	2545.2	2747.4	2969.7	3277.5	3557.3	3963.7	4296.4	4705.0	5061.9	5566.6	5999.6	6529.3	7005.7	7556.9	8205.6
Real	1911.1	1888.3	1965.2	1963.9	1952.6	1984.7	2038.5	2096.5	2201.5	2273.5	2410.3	2485.8	2590.2	2651.4	2774.3	2845.0	2945.9	3007.5	3086.7	3189.0
NPV (9.54% discount rate)	32148.0																			
Average Growth																				
Nominal	7.97%																			
Real	2.73%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.4	50.2	52.0	54.9	58.0	62.2	65.5	71.1	75.0	80.0	83.7	90.2	94.6	100.3	104.9	110.9	117.7
Real	45.9	43.4	43.9	42.6	41.1	40.5	40.8	41.0	41.8	41.8	43.3	43.4	44.0	43.9	44.9	44.8	45.3	45.0	45.3	45.8
Average Growth																				
Nominal	5.08%																			
Real	-0.02%																			
Average Customer Bill ($)																				
Nominal	1566.5	1589.6	1711.9	1769.5	1808.0	1882.5	1982.0	2094.6	2256.9	2395.8	2611.8	2765.4	2960.4	3118.9	3363.7	3560.8	3806.9	4008.5	4236.7	4508.3
Real	1566.5	1512.5	1549.8	1524.2	1481.8	1468.0	1470.5	1478.7	1516.0	1531.2	1588.2	1600.0	1629.8	1633.7	1676.4	1688.5	1717.6	1720.8	1730.5	1752.1
NPV (9.54% discount rate)	21853.5																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.4	1988.8	2179.7	2295.9	2408.3	2583.9	2807.0	3054.0	3388.0	3695.1	4130.0	4493.1	4934.0	5325.2	5865.5	6328.7	6870.4	7360.2	7924.3	8585.9
Real	1912.4	1892.3	1973.3	1977.6	1973.8	2014.9	2082.7	2156.0	2275.7	2361.6	2511.4	2599.6	2716.2	2789.3	2923.2	3001.0	3099.8	3159.7	3236.8	3336.8
NPV (9.54% discount rate)	33165.3																			
Average Growth																				
Nominal	8.22%																			
Real	2.97%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.5	50.3	52.1	55.1	58.2	62.3	65.6	71.1	75.0	79.9	83.6	89.9	94.3	99.7	104.0	109.7	116.1
Real	45.9	43.5	43.9	42.6	41.2	40.6	40.9	41.1	41.9	41.9	43.3	43.4	44.0	43.8	44.8	44.7	45.0	44.6	44.8	45.1
Average Growth																				
Nominal	5.00%																			
Real	-0.09%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
DSR yield minus 30%

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	2	5	9	15	23	31	38	47	55	63	71	79	87	94	101	108	114	121	128	135
D.S. Options (1)	7	14	23	38	61	91	127	163	198	230	259	288	316	342	361	372	383	393	402	412
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Small CT (Jul) (1)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (4)					4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Wyodak 2 (1)										192	192	192	192	192	192	192	192	192	192	192
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Small CT (1)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (2)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (3)								8	8	8	8	8	8	8	8	8	8	8	8	8
Large CT (Jul) (1)								16	31	31	31	31	31	31	31	31	31	31	31	31
Medium CT (1)								20	20	20	20	20	20	20	20	20	20	20	20	20
Large CT (3)									31	31	31	31	31	31	31	31	31	31	31	31
Hunter 4 (1)														300	300	300	300	300	300	300
Large CC CT (Jul) (1)											88	175	175	175	175	175	175	175	175	175
Large CC CT (2)												175	175	175	175	175	175	175	175	175
Large CT (4)												31	31	31	31	31	31	31	31	31
Large CT (5)												31	31	31	31	31	31	31	31	31
Large CT (Jul)													16	31	31	31	31	31	31	31
Medium CT													20	20	20	20	20	20	20	20
Small CT															8	8	8	8	8	8
Medium CT (Jul)															10	20	20	20	20	20
Large CC CT																175	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Medium CT (Jul)																			10	20
Medium CT (Jul)																			10	20
Large CC CT																				175
Medium CC CT																				64
Medium CT (Jul)																				10
total	6,693	6,776	7,008	7,189	7,326	7,525	7,777	7,859	8,083	8,331	8,509	8,797	8,920	9,202	9,257	9,422	9,651	9,781	9,973	10,191
Balance	176	171	215	207	118	123	182	86	93	134	82	163	163	302	151	183	202	170	157	155

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
DSR yield minus 30%

4/7/92 9:47

Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	3	7	12	21	32	43	55	67	79	91	103	115	127	138	149	160	172	183	194	206
D.S. Options (1)	8	17	31	52	91	143	206	269	328	382	431	479	525	568	600	618	636	653	669	684
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (4)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (Jul) (1)									156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)														400	400	400	400	400	400	400
Large CC CT (Jul) (1)												250	250	250	250	250	250	250	250	250
Large CC CT (2)												250	250	250	250	250	250	250	250	250
Large CT (4)												156	156	156	156	156	156	156	156	156
Large CT (5)												156	156	156	156	156	156	156	156	156
Large CT (Jul)														156	156	156	156	156	156	156
Medium CT													100	100	100	100	100	100	100	100
Small CT															40	40	40	40	40	40
Medium CT (Jul)																100	100	100	100	100
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Medium CT (Jul)																				100
Medium CT (Jul)																				100
Large CC CT																				250
Medium CC CT																				128
Medium CT (Jul)																				
total	9,474	9,854	10,149	10,546	10,705	11,077	11,894	12,250	12,670	13,050	13,136	14,005	14,127	14,742	14,696	15,093	15,329	15,608	15,719	16,342
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,422	1,497	1,538	1,594	1,642	1,645	1,767	1,782	1,865	1,871	1,924	1,961	1,999	2,036	2,123
Balance	-158	2	59	174	131	191	680	686	796	819	597	1,037	1,052	1,396	1,038	1,292	1,212	1,179	1,044	1,288
(Reserve+Balance)/Requirement	14%	15%	15%	17%	16%	17%	22%	22%	23%	23%	21%	25%	25%	28%	25%	27%	26%	26%	24%	26%

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
DSR yield minus 30%

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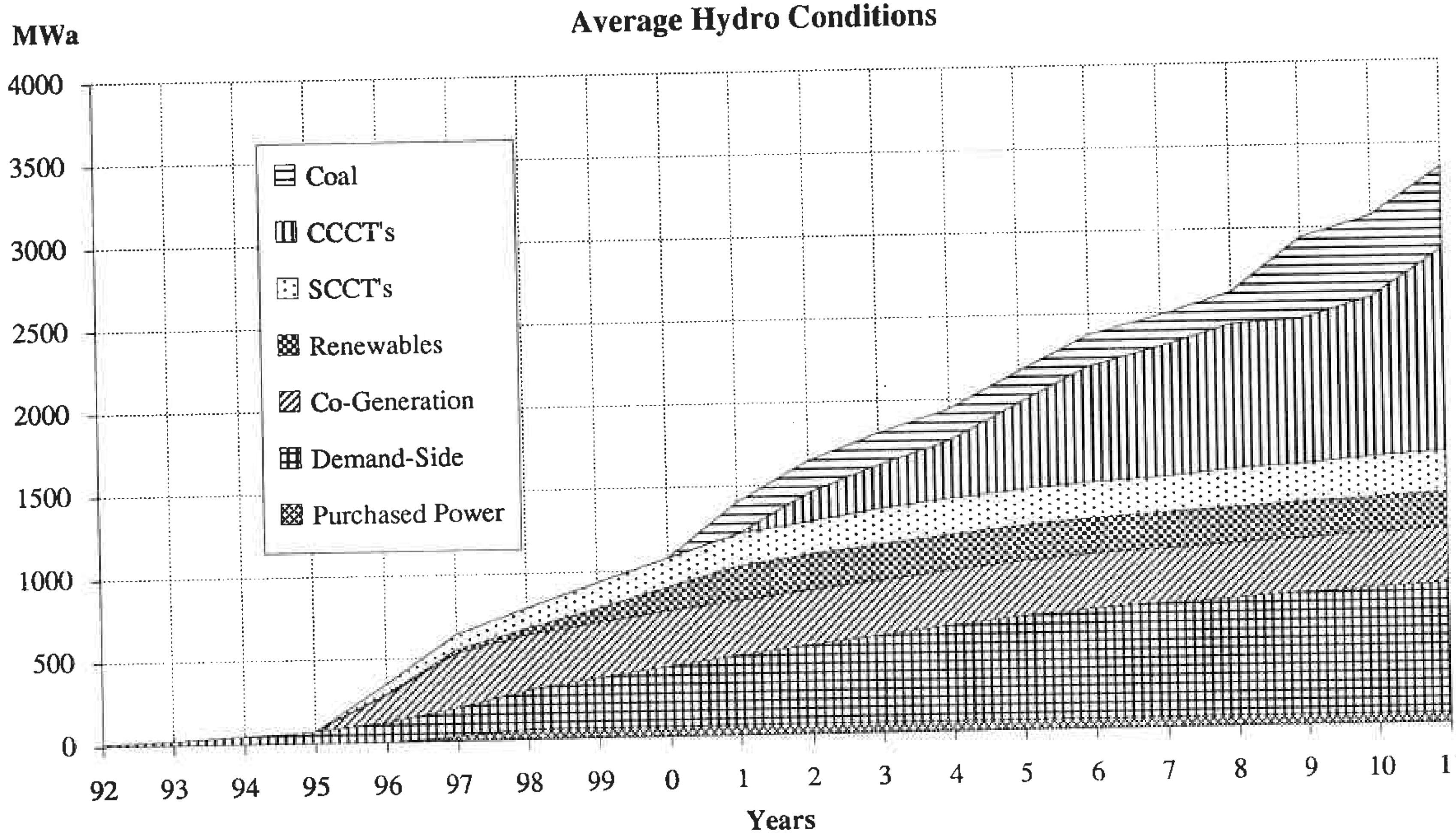
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	2	5	9	15	23	30	38	46	54	62	70	78	86	93	101	108	116	123	130	138
D.S. Options (1)	7	13	24	41	73	117	169	220	270	316	361	404	447	485	514	531	547	563	577	591
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (4)					40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (Jul) (1)								156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (3)									156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)														400	400	400	400	400	400	400
Large CC CT (Jul) (1)											250	250	250	250	250	250	250	250	250	250
Large CC CT (2)												250	250	250	250	250	250	250	250	250
Large CT (4)												156	156	156	156	156	156	156	156	156
Large CT (5)												156	156	156	156	156	156	156	156	156
Large CT (Jul)													156	156	156	156	156	156	156	156
Medium CT													100	100	100	100	100	100	100	100
Small CT															40	40	40	40	40	40
Medium CT (Jul)															100	100	100	100	100	100
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Medium CT (Jul)																			100	100
Medium CT (Jul)																			100	100
Large CC CT																				250
Medium CC CT																				128
Medium CT (Jul)																				100
total	9,779	9,825	10,139	10,471	10,701	10,893	11,238	11,701	11,983	12,346	12,666	13,242	13,549	14,000	14,061	14,390	14,669	14,943	15,265	15,767
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,358	1,422	1,497	1,538	1,594	1,642	1,645	1,767	1,782	1,865	1,871	1,924	1,961	1,999	2,036	2,123
Balance	77	85	161	222	67	-10	16	255	170	280	301	459	667	867	613	805	776	823	866	998
(Reserve+Balance)/Requirement	16%	16%	17%	17%	15%	15%	16%	18%	17%	18%	18%	20%	22%	24%	21%	23%	23%	23%	23%	25%

PacifiCorp - RAMPP 2

Illustrative Plan

Average Hydro Conditions



KEY OUTPUTS

Average Hydro Condition

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6778.0	7085.4	7446.8	7924.2	8699.0	9603.9	10600.9	11476.6	12145.1	12728.0	13346.3	14129.7	15016.3	15863.4	16709.4	17561.8	18069.0	18347.4
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.0	2169.2	2276.8	2381.1	2545.0	2729.6	2922.7	3190.1	3467.3	3862.7	4180.3	4546.2	4838.9	5267.7	5731.1	6274.9	6714.3	7314.5	7937.4
Real	1910.8	1887.7	1963.8	1961.2	1951.5	1984.6	2025.3	2063.3	2142.8	2216.0	2348.9	2418.7	2502.7	2534.6	2625.3	2717.7	2831.2	2882.4	2987.7	3084.8
NPV (9.54% discount rate)	31453.5																			
Average Growth																				
Nominal	7.78%																			
Real	2.55%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.5	49.5	50.4	52.3	55.0	57.7	61.4	64.9	70.6	74.5	79.0	81.9	87.4	92.6	98.9	103.2	110.2	116.9
Real	45.9	43.5	43.9	42.6	41.3	40.8	40.8	40.8	41.2	41.5	42.9	43.1	43.5	42.9	43.6	43.9	44.6	44.3	45.0	45.5
Average Growth																				
Nominal	5.04%																			
Real	-0.05%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.1	1710.8	1767.0	1807.0	1882.4	1969.2	2061.4	2196.7	2335.2	2545.3	2690.7	2860.5	2981.5	3183.1	3401.4	3658.6	3841.8	4100.8	4361.0
Real	1566.3	1512.0	1548.8	1522.1	1481.0	1467.9	1461.0	1455.3	1475.6	1492.4	1547.8	1556.8	1574.7	1561.7	1586.4	1613.0	1650.7	1649.2	1675.0	1694.8
NPV (9.54% discount rate)	21425.5																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.1	2178.2	2292.7	2407.0	2583.7	2789.2	3007.0	3300.5	3605.2	4029.0	4377.0	4775.1	5102.2	5566.6	6060.2	6616.0	7068.8	7681.9	8317.7
Real	1912.2	1891.7	1972.0	1974.9	1972.7	2014.8	2069.5	2122.8	2217.0	2304.1	2450.0	2532.5	2628.8	2672.5	2774.3	2873.7	2985.1	3034.6	3137.8	3232.6
NPV (9.54% discount rate)	32470.8																			
Average Growth																				
Nominal	8.04%																			
Real	2.80%																			
Mills / KWh																				
Nominal	45.9	45.7	48.5	49.4	50.3	52.1	54.7	57.3	60.7	64.0	69.4	73.1	77.3	80.1	85.3	90.3	96.0	99.9	106.3	112.5
Real	45.9	43.4	43.9	42.6	41.2	40.6	40.6	40.4	40.8	40.9	42.2	42.3	42.6	42.0	42.5	42.8	43.3	42.9	43.4	43.7
Average Growth																				
Nominal	4.83%																			
Real	-0.26%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Average Hydro Condition

	1,992	1,993	1,994	1,995	1,996	1,997	1,998	1,999	2,000	2,001	2,002	2,003	2,004	2,005	2,006	2,007	2,008	2,009	2,010	2,011
Average Megawatts																				
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
Average Water (1)	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CT (1)					31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (2)					31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
CoGen (2)						80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (2)						85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CT (3)						31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Wyodak 2 (1)										192	192	192	192	192	192	192	192	192	192	192
Large CT (4)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (5)								31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (1)									16	31	31	31	31	31	31	31	31	31	31	31
Small CT (Jul) (1)									4	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (1)											175	175	175	175	175	175	175	175	175	175
Large CC CT (Jul) (1)												88	175	175	175	175	175	175	175	175
Medium CT (1)												20	20	20	20	20	20	20	20	20
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT (Jul)																88	175	175	175	175
Small CT																	8	8	8	8
Small CT																	8	8	8	8
Hunter 4																		300	300	300
Large CC CT (Jul)																			88	175
Small CT																			8	8
Small CT																			8	8
Large CC CT																				175
total	6,847	6,934	7,171	7,201	7,393	7,614	7,854	7,926	8,141	8,425	8,706	8,795	8,984	9,139	9,363	9,439	9,603	9,865	9,973	10,191
Balance	330	329	379	219	185	212	259	152	152	229	280	161	227	239	257	199	154	254	157	155

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Average Hydro Condition

Winter Peak

Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
Average Water (1)																				
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
CoGen (2)						94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (2)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (3)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (4)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (5)								156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)										156	156	156	156	156	156	156	156	156	156	156
Small CT (Jul) (1)										40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)											250	250	250	250	250	250	250	250	250	250
Large CC CT (Jul) (1)													250	250	250	250	250	250	250	250
Medium CT (1)												100	100	100	100	100	100	100	100	100
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																	250	250	250	250
Small CT																	40	40	40	40
Small CT																	40	40	40	40
Hunter 4																		400	400	400
Large CC CT (Jul)																				250
Small CT																			40	40
Small CT																			40	40
Large CC CT																				250
total	9,479	9,865	10,167	10,389	10,875	11,215	11,908	12,231	12,371	12,975	13,337	13,520	13,817	14,149	14,331	14,391	14,719	15,160	15,113	15,569
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,376	1,431	1,482	1,513	1,523	1,601	1,641	1,656	1,693	1,731	1,768	1,768	1,818	1,878	1,890	1,965
Balance	-153	13	77	46	284	320	709	692	567	786	803	662	830	938	776	745	745	852	584	774
(Reserve+Balance)/Requirement	14%	15%	16%	15%	18%	19%	23%	22%	20%	23%	22%	21%	22%	23%	22%	21%	21%	22%	20%	21%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Average Hydro Condition

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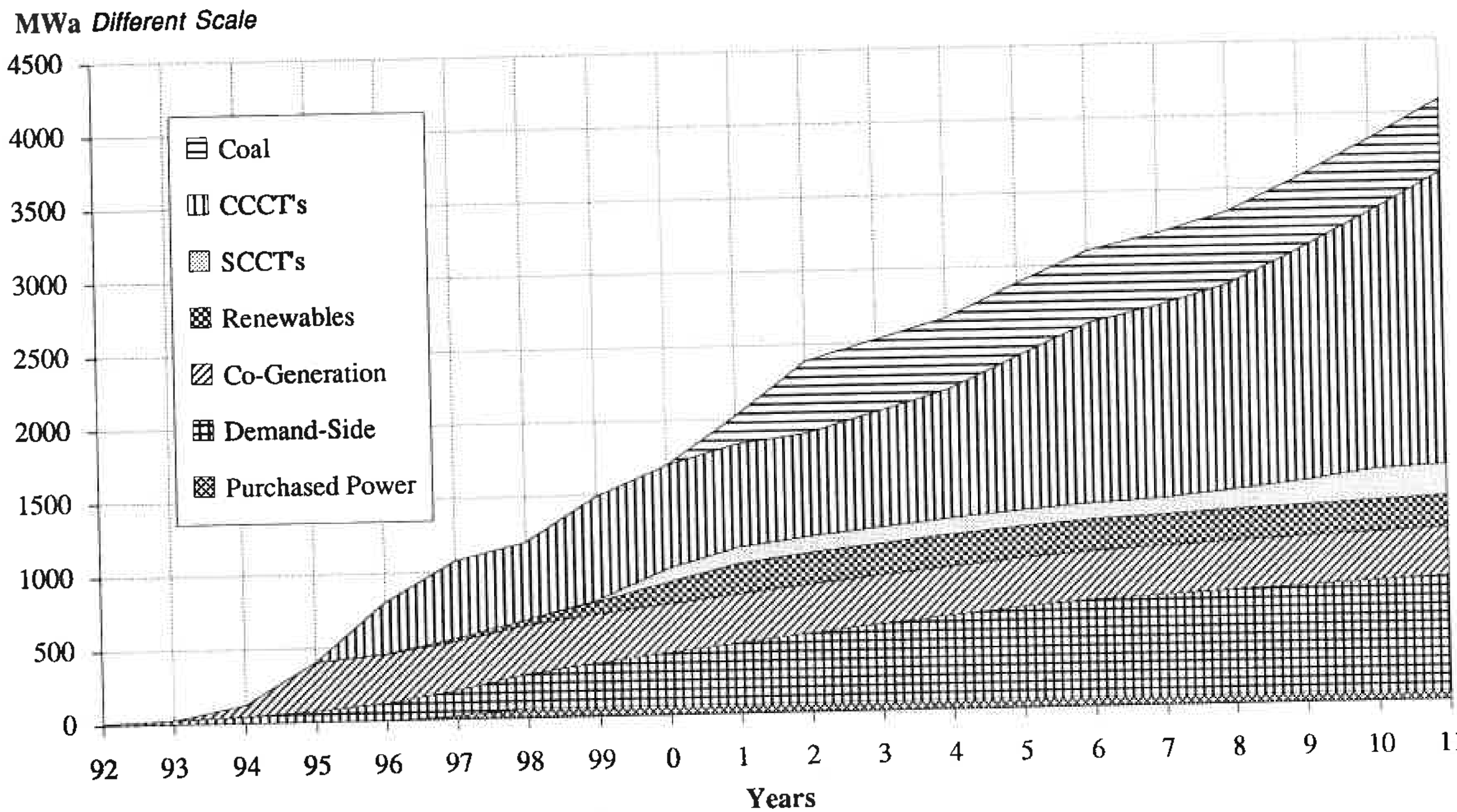
Summer Peak

Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
Average Water (1)																				
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
CoGen (2)						94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (2)						100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (3)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (4)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (5)								156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)									156	156	156	156	156	156	156	156	156	156	156	156
Small CT (Jul) (1)									40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (1)											250	250	250	250	250	250	250	250	250	250
Large CC CT (Jul) (1)												250	250	250	250	250	250	250	250	250
Medium CT (1)												100	100	100	100	100	100	100	100	100
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																250	250	250	250	250
Small CT																	40	40	40	40
Small CT																	40	40	40	40
Hunter 4																		400	400	400
Large CC CT (Jul)																			250	250
Small CT																			40	40
Small CT																			40	40
Large CC CT																				250
total	9,783	9,833	10,154	10,307	10,700	11,014	11,229	11,497	11,844	12,231	12,573	12,958	13,031	13,352	13,538	13,878	13,997	14,431	14,643	14,926
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,376	1,431	1,482	1,513	1,523	1,601	1,641	1,656	1,693	1,731	1,768	1,768	1,818	1,878	1,890	1,965
Balance	81	93	176	86	48	102	21	75	102	206	212	286	238	354	193	448	248	431	390	315
(Reserve+Balance)/Requirement	16%	17%	17%	16%	15%	16%	15%	16%	16%	17%	17%	18%	17%	18%	17%	19%	17%	19%	18%	18%

PacifiCorp - RAMPP 2

Illustrative Plan

10% Less Thermal Resources



KEY OUTPUTS

10% Less Thermal

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.0	5610.0	5792.0	5978.0	6180.0	6366.0	6557.0	6788.0	7018.0	7250.0	7480.0	7711.0	7931.0	8146.0	8384.0	8604.0	8814.0	9020.0	9233.0
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5409.7	5583.6	5745.9	5902.5	6060.2	6192.1	6320.2	6488.1	6657.0	6832.0	7008.0	7186.9	7355.8	7523.6	7724.8	7919.4	8103.9	8285.6	8475.0
Energy Sales after Conservation	4749.7	4945.5	5104.5	5252.9	5396.1	5540.3	5660.8	5777.9	5931.4	6085.8	6245.8	6406.7	6570.3	6724.7	6878.1	7062.0	7239.9	7408.6	7574.7	7747.8
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6537.3	6965.9	7424.5	7862.7	8370.1	9261.8	10499.0	11766.4	12798.7	13526.6	14030.9	14610.3	15254.4	15820.6	16398.2	17146.6	18042.5	18684.2	19008.3
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1984.6	2181.0	2299.4	2436.3	2648.2	2860.3	3052.1	3381.3	3731.2	4153.5	4575.9	4923.9	5221.5	5648.4	6120.6	6663.7	7120.7	7735.7	8389.2
Real	1910.8	1888.3	1974.5	1980.7	1996.8	2065.1	2122.3	2154.7	2271.2	2384.7	2525.7	2647.5	2710.7	2735.0	2815.1	2902.4	3006.6	3056.9	3159.7	3260.4
NPV (9.54% discount rate)	32987.2																			
Average Growth																				
Nominal	8.10%																			
Real	2.85%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.8	50.0	51.5	54.4	57.7	60.3	65.1	69.8	75.9	81.5	85.6	88.4	93.7	98.9	105.1	109.4	116.6	123.6
Real	45.9	43.5	44.2	43.0	42.2	42.4	42.8	42.6	43.7	44.6	46.2	47.2	47.1	46.3	46.7	46.9	47.4	47.0	47.6	48.0
Average Growth																				
Nominal	5.35%																			
Real	0.24%																			
Average Customer Bill ($)																				
Nominal	1566.3	1589.6	1720.1	1784.6	1848.9	1958.8	2063.4	2152.7	2328.4	2512.9	2736.9	2945.3	3098.2	3217.2	3413.2	3632.6	3885.3	4074.3	4336.9	4609.2
Real	1566.3	1512.4	1557.2	1537.2	1515.3	1527.5	1531.0	1519.7	1564.0	1606.0	1664.3	1704.1	1705.6	1685.2	1701.1	1722.6	1753.0	1749.1	1771.4	1791.3
NPV (9.54% discount rate)	22406.4																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.2	1988.7	2190.0	2315.4	2462.2	2687.0	2919.9	3136.4	3491.8	3869.1	4319.7	4772.6	5152.9	5484.8	5947.3	6449.8	7004.8	7475.2	8103.0	8769.6
Real	1912.2	1892.2	1982.7	1994.4	2017.9	2095.3	2166.5	2214.2	2345.4	2472.8	2626.8	2761.3	2836.8	2873.0	2964.0	3058.5	3160.5	3209.1	3309.8	3408.2
NPV (9.54% discount rate)	34004.5																			
Average Growth																				
Nominal	8.35%																			
Real	3.09%																			
Mills / KWh																				
Nominal	45.9	45.7	48.7	49.9	51.4	54.1	57.3	59.7	64.2	68.7	74.4	79.7	83.4	86.1	91.2	96.1	101.7	105.6	112.2	118.6
Real	45.9	43.5	44.1	43.0	42.2	42.2	42.5	42.2	43.1	43.9	45.2	46.1	45.9	45.1	45.4	45.6	45.9	45.3	45.8	46.1
Average Growth																				
Nominal	5.12%																			
Real	0.02%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
10% Less Thermal

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,610	5,792	5,978	6,180	6,366	6,557	6,788	7,018	7,250	7,480	7,711	7,931	8,146	8,384	8,604	8,814	9,020	9,233	9,453
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,605	6,792	6,982	7,208	7,402	7,595	7,773	7,989	8,196	8,426	8,634	8,757	8,900	9,106	9,239	9,449	9,611	9,816	10,036
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	10	19	33	54	87	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
CoGen (1)			80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
Loss of Thermal (1)		-57	-115	-173	-231	-289	-348	-406	-464	-522	-580	-580	-580	-580	-580	-580	-580	-580	-580	-580
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CC CT (1)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CC CT (2)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CC CT (3)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Wyodak 2 (1)										192	192	192	192	192	192	192	192	192	192	192
Hunter 4 (1)											300	300	300	300	300	300	300	300	300	300
Large CC CT (4)								175	175	175	175	175	175	175	175	175	175	175	175	175
Medium CT (Jul) (1)								10	20	20	20	20	20	20	20	20	20	20	20	20
Large CT (1)									31	31	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (1)									16	31	31	31	31	31	31	31	31	31	31	31
Medium CT (1)									20	20	20	20	20	20	20	20	20	20	20	20
Small CT (Jul) (1)									4	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (Jul) (1)												88	175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT (Jul)																88	175	175	175	175
Small CT																	8	8	8	8
Small CT																	8	8	8	8
Small CT																	8	8	8	8
Large CC CT																		175	175	175
Small CT																		8	8	8
Small CT (Jul)																		4	8	8
Small CT (Jul)																		4	8	8
Medium CT (Jul)																		10	20	20
Large CC CT																			175	175
Large CT																			31	31
Large CC CT																				175
Medium CC CT																				64
total	6,697	6,727	6,987	7,208	7,465	7,606	7,757	7,924	8,142	8,369	8,717	8,785	8,974	9,130	9,353	9,429	9,601	9,765	9,992	10,188
Balance	180	122	194	226	257	204	161	151	153	172	290	151	217	230	247	190	152	153	176	152

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
10% Less Thermal

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,299	7,537	7,786	8,056	8,305	8,558	8,867	9,171	9,479	9,785	10,093	10,385	10,672	10,986	11,277	11,555	11,829	12,113	12,405
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,552	8,790	9,043	9,215	9,464	9,717	10,026	10,280	10,588	10,894	11,202	11,294	11,481	11,787	11,878	12,156	12,430	12,639	12,931
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	18	30	46	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	12	24	44	74	130	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
Loss of Thermal (1)																				
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)				100	100	100	100	.100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Hunter 4 (1)											400	400	400	400	400	400	400	400	400	400
Large CC CT (4)								250	250	250	250	250	250	250	250	250	250	250	250	250
Medium CT (Jul) (1)									100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)										156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)										40	40	40	40	40	40	40	40	40	40	40
Large CC CT (Jul) (1)													250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																	250	250	250	250
Small CT																	40	40	40	40
Small CT																	40	40	40	40
Small CT																	40	40	40	40
Large CC CT																		250	250	250
Small CT																		40	40	40
Small CT (Jul)																			40	40
Small CT (Jul)																			40	40
Medium CT (Jul)																			100	100
Large CC CT																			250	250
Large CT																			156	156
Large CC CT																				250
Medium CC CT																				128
total	9,479	9,865	10,261	10,777	11,257	11,497	12,034	12,451	12,947	13,551	14,063	14,146	14,443	14,775	14,957	15,017	15,385	15,716	16,175	16,609
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,314	1,358	1,433	1,473	1,501	1,546	1,610	1,687	1,750	1,750	1,787	1,825	1,862	1,862	1,918	1,961	2,049	2,106
Balance	-153	13	157	376	609	560	816	879	1,057	1,275	1,420	1,194	1,362	1,470	1,308	1,277	1,311	1,325	1,487	1,573
(Reserve+Balance)/Requirement	14%	15%	17%	19%	22%	21%	24%	24%	26%	28%	29%	26%	28%	29%	27%	26%	27%	26%	28%	28%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
10% Less Thermal

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Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,589	6,827	7,061	7,302	7,562	7,802	8,046	8,369	8,665	8,965	9,261	9,557	9,841	10,117	10,426	10,710	10,981	11,246	11,487	11,770
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,402	8,440	8,678	8,921	9,276	9,481	9,725	9,908	10,219	10,424	10,720	11,016	11,100	11,268	11,577	11,661	11,932	12,122	12,363	12,646
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	7	13	21	32	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	10	19	35	59	105	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
CoGen (1)			94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
Loss of Thermal (1)																				
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Hunter 4 (1)											400	400	400	400	400	400	400	400	400	400
Large CC CT (4)								250	250	250	250	250	250	250	250	250	250	250	250	250
Medium CT (Jul) (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)									156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
Small CT (Jul) (1)									40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (Jul) (1)												250	250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT (Jul)																250	250	250	250	250
Small CT																	40	40	40	40
Small CT																	40	40	40	40
Small CT																	40	40	40	40
Large CC CT																		250	250	250
Small CT																		40	40	40
Small CT (Jul)																		40	40	40
Small CT (Jul)																		40	40	40
Medium CT (Jul)																		100	100	100
Large CC CT																			250	250
Large CT																			156	156
Large CC CT																				250
Medium CC CT																				128
total	9,783	9,833	10,248	10,695	11,082	11,296	11,355	11,817	12,420	12,807	13,299	13,584	13,657	13,978	14,164	14,504	14,663	15,167	15,455	15,866
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,314	1,358	1,433	1,473	1,501	1,546	1,610	1,687	1,750	1,750	1,787	1,825	1,862	1,862	1,918	1,961	2,049	2,106
Balance	81	93	256	416	373	342	129	362	592	695	829	819	770	886	725	980	814	1,084	1,043	1,114
(Reserve+Balance)/Requirement	16%	17%	18%	20%	19%	19%	17%	19%	22%	23%	24%	23%	23%	24%	22%	24%	23%	25%	25%	25%

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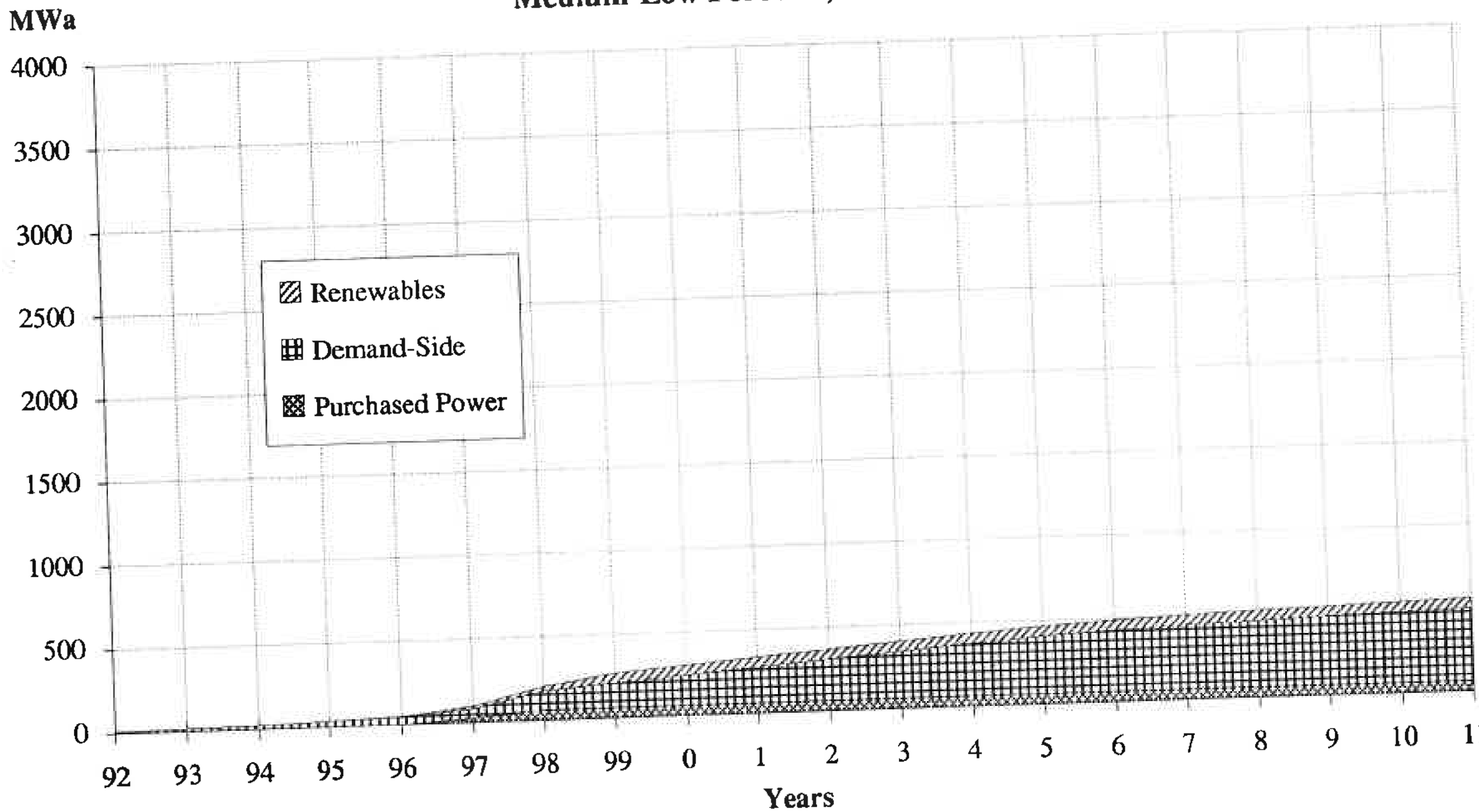
PacifiCorp - RAMPP 2

Illustrative Plan

Medium-Low Forecast, Low Actuals



KEY OUTPUTS
Medium Low Forecast / Low Actual

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5075.0	5099.9	5125.4	5151.0	5177.3	5202.6	5228.7	5254.8	5281.6	5307.5	5334.0	5360.7	5388.1	5414.4	5441.5	5468.7	5496.6	5523.5	5551.1
Total Conservation	4.5	9.3	16.5	25.7	35.7	46.8	58.5	114.5	146.5	179.3	212.8	247.0	280.9	314.0	342.5	366.1	383.0	397.5	410.7	423.3
System Load net of Conservation	5195.5	5065.7	5083.4	5099.7	5115.3	5130.5	5144.2	5114.2	5108.3	5102.4	5094.7	5087.0	5079.8	5074.1	5071.9	5075.4	5085.7	5099.1	5112.8	5127.9
Energy Sales after Conservation	4749.7	4631.1	4647.2	4662.1	4676.4	4690.3	4702.8	4675.4	4670.0	4664.6	4657.6	4650.6	4643.9	4638.7	4636.8	4640.0	4649.3	4661.6	4674.1	4687.9
Total Customers (000's)	1,198	1,200	1,211	1,219	1,222	1,228	1,236	1,243	1,250	1,255	1,260	1,268	1,275	1,283	1,292	1,299	1,308	1,318	1,330	1,342
Net Electric Plant (M$)	5941.6	6486.7	6732.8	6906.9	7072.2	7302.8	7521.0	7742.3	7914.9	8115.5	8359.1	8654.7	8972.6	9314.2	9674.6	10043.6	10432.8	10837.9	11262.9	11704.5
Net Conservation Assets	11.9	40.4	79.2	131.7	194.2	272.1	321.7	373.3	429.1	501.4	604.6	746.5	897.0	1056.3	1218.9	1374.2	1532.3	1687.8	1843.1	1994.2
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.0	1930.5	2098.8	2180.0	2245.5	2266.9	2357.4	2409.7	2539.1	2619.6	2713.8	2808.6	2921.3	3053.6	3201.4	3362.1	3534.0	3683.4	3875.1	4064.4
Real	1910.0	1836.8	1900.0	1877.8	1840.4	1767.7	1749.1	1701.2	1705.5	1674.2	1650.3	1625.0	1608.2	1599.5	1595.5	1594.3	1594.5	1581.3	1582.8	1579.6
NPV (9.54% discount rate)	23955.6																			
Average Growth																				
Nominal	4.05%																			
Real	-0.99%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	47.5	51.6	53.4	54.8	55.0	57.2	58.8	62.1	63.9	66.5	68.9	71.8	74.9	78.8	82.7	86.8	90.0	94.6	99.0
Real	45.9	45.2	46.7	46.0	44.9	42.9	42.5	41.5	41.7	40.9	40.4	39.9	39.5	39.3	39.3	39.2	39.2	38.6	38.7	38.5
Average Growth																				
Nominal	4.13%																			
Real	-0.93%																			
Average Customer Bill ($)																				
Nominal	1594.5	1609.0	1732.6	1788.8	1837.5	1845.5	1907.0	1938.6	2032.0	2087.9	2154.0	2215.1	2291.0	2379.3	2477.9	2588.4	2702.0	2794.6	2912.9	3029.6
Real	1594.5	1530.9	1568.5	1540.8	1506.0	1439.2	1415.0	1368.6	1364.9	1334.4	1309.9	1281.6	1261.2	1246.3	1234.9	1227.4	1219.1	1199.7	1189.8	1177.4
NPV (9.54% discount rate)	19192.8																			
Customer Cost (M$)	2.8	2.6	3.2	3.6	3.8	1.8	1.9	1.8	2.1	2.0	2.5	3.3	3.6	4.3	9.5	16.7	34.2	48.2	70.8	86.2
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.5	0.9	1.2	1.6	1.8	2.0	2.2	2.4	2.6	2.9	3.2	3.6	4.0	5.0	6.7	10.2	15.1	22.3	31.1
NPV (9.54% discount rate)	32.6																			
Energy Services Charge (M$)	1.1	2.5	5.2	9.2	14.2	20.7	25.6	30.9	37.0	45.1	56.8	73.0	91.2	111.2	133.0	154.9	164.2	172.1	178.7	183.4
NPV (9.54% discount rate)	439.3																			
Total Resource Cost (M$)																				
Nominal	1911.4	1933.5	2104.9	2190.4	2261.4	2289.4	2384.9	2442.8	2578.5	2667.3	2773.5	2884.8	3016.0	3168.8	3339.4	3523.6	3708.4	3870.6	4076.1	4278.9
Real	1911.4	1839.6	1905.5	1886.8	1853.4	1785.3	1769.5	1724.6	1732.0	1704.7	1686.6	1669.1	1660.4	1659.8	1664.3	1670.9	1673.2	1661.6	1664.9	1662.9
NPV (9.54% discount rate)	24427.4																			
Average Growth																				
Nominal	4.33%																			
Real	-0.73%																			
Mills / KWh																				
Nominal	45.9	47.4	51.5	53.4	54.8	55.1	57.2	58.3	61.3	62.9	65.3	67.5	70.3	73.2	77.0	80.9	84.7	87.7	92.1	96.2
Real	45.9	45.1	46.7	46.0	44.9	42.9	42.5	41.2	41.2	40.2	39.7	39.1	38.7	38.4	38.4	38.3	38.2	37.6	37.6	37.4
Average Growth																				
Nominal	3.97%																			
Real	-1.07%																			

PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
Medium Low Forecast/Low Actuals

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	5,075	5,100	5,125	5,151	5,177	5,203	5,229	5,255	5,282	5,307
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946
total	6,169	6,095	6,126	6,155	6,205	6,239	6,267	6,240	6,253	6,254
Resources										
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316
Firm Purchases	612	632	675	682	554	535	566	558	556	551
D.S. Lost Opportunities (1)	2	4	8	13	18	23	24	28	32	37
D.S. Options (1)	7	12	17	23	29	36	91	118	147	176
BPA Entitlement (1)						26	65	65	65	65
Geothermal-Pilot (1)							11	45	45	45
Wind-Pilot (1)					5	15	15	15	15	15
total	6,693	6,774	7,001	7,012	6,943	6,917	7,115	7,109	7,216	7,205
Balance	524	679	875	856	738	679	849	869	963	951

Average Megawatts	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	5,334	5,361	5,388	5,414	5,441	5,469	5,497	5,524	5,551	5,579
Firm Sales	946	923	826	754	722	635	635	591	583	583
total	6,280	6,284	6,214	6,168	6,164	6,104	6,132	6,115	6,134	6,162
Resources										
Existing Generation	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	41	45	49	54	58	62	66	70	74	78
D.S. Options (1)	206	236	265	289	308	321	332	341	349	357
BPA Entitlement (1)	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)	45	45	45	45	45	45	45	45	45	45
Wind-Pilot (1)	15	15	15	15	15	15	15	15	15	15
total	7,281	7,243	7,327	7,289	7,324	7,304	7,354	7,305	7,298	7,242
Balance	1,001	960	1,113	1,121	1,161	1,200	1,222	1,191	1,164	1,081

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PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
Medium Low Forecast/Low Actuals

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,587	6,620	6,653	6,686	6,720	6,753	6,787	6,821	6,855	6,889	6,924	6,958	6,993	7,028	7,063	7,099	7,134	7,170	7,206	7,242
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	7,864	7,873	7,906	7,943	7,879	7,912	7,946	7,980	7,964	7,998	8,033	8,067	7,902	7,837	7,864	7,700	7,735	7,771	7,732	7,768
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	2	6	12	18	25	32	33	40	47	53	60	66	73	79	86	92	99	106	113	119
D.S. Options (1)	9	16	24	33	44	57	148	196	245	295	347	399	448	489	521	542	559	574	588	601
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	50	50	50	50	50	50	50	50	50	50	50	50
Wind-Pilot (1)						16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
total	9,474	9,852	10,141	10,335	10,263	10,181	10,681	10,796	10,823	10,872	10,939	10,995	11,014	11,066	10,977	11,023	11,002	11,025	10,880	10,917
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,300	1,302	1,327	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334
Balance	310	679	935	1,092	1,084	967	1,408	1,482	1,524	1,539	1,572	1,593	1,778	1,895	1,778	1,988	1,933	1,920	1,814	1,814
(Reserve+Balance)/Requirement	20%	25%	28%	30%	30%	29%	34%	35%	36%	36%	36%	36%	39%	41%	40%	43%	42%	42%	41%	41%

PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
Medium Low Forecast/Low Actuals

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Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	6,140	6,171	6,202	6,233	6,264	6,295	6,327	6,358	6,390	6,422
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459
total	7,953	7,784	7,819	7,852	7,978	7,974	8,006	7,897	7,944	7,881
Resources										
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130
D.S. Lost Opportunities (1)	2	4	8	13	18	22	23	28	32	37
D.S. Options (1)	7	12	18	25	35	46	120	158	197	236
BPA Entitlement (1)										
Geothermal-Pilot (1)								50	50	50
Wind-Pilot (1)						10	10	10	10	10
total	9,779	9,823	10,132	10,265	10,109	10,015	10,049	10,119	10,171	10,208
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,300	1,300	1,302	1,327	1,334	1,334	1,334
Balance	526	739	1,014	1,113	832	739	717	887	893	993
(Reserve+Balance)/Requirement	23%	26%	30%	31%	27%	26%	26%	28%	28%	30%

Summer Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	6,454	6,486	6,519	6,551	6,584	6,617	6,650	6,683	6,717	6,750
Firm Sales	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	7,913	7,945	7,778	7,702	7,735	7,568	7,601	7,559	7,593	7,626
Resources										
Existing Generation	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	41	45	50	54	58	63	67	72	76	80
D.S. Options (1)	277	318	358	393	421	439	454	467	479	491
BPA Entitlement (1)										
Geothermal-Pilot (1)	50	50	50	50	50	50	50	50	50	50
Wind-Pilot (1)	10	10	10	10	10	10	10	10	10	10
total	10,260	10,267	10,313	10,357	10,274	10,351	10,376	10,395	10,262	10,279
Reserve Requirement										
Total Company Reserve	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334
Balance	1,012	988	1,201	1,321	1,204	1,449	1,441	1,501	1,335	1,318
(Reserve+Balance)/Requirement	30%	29%	33%	34%	33%	37%	37%	38%	35%	35%

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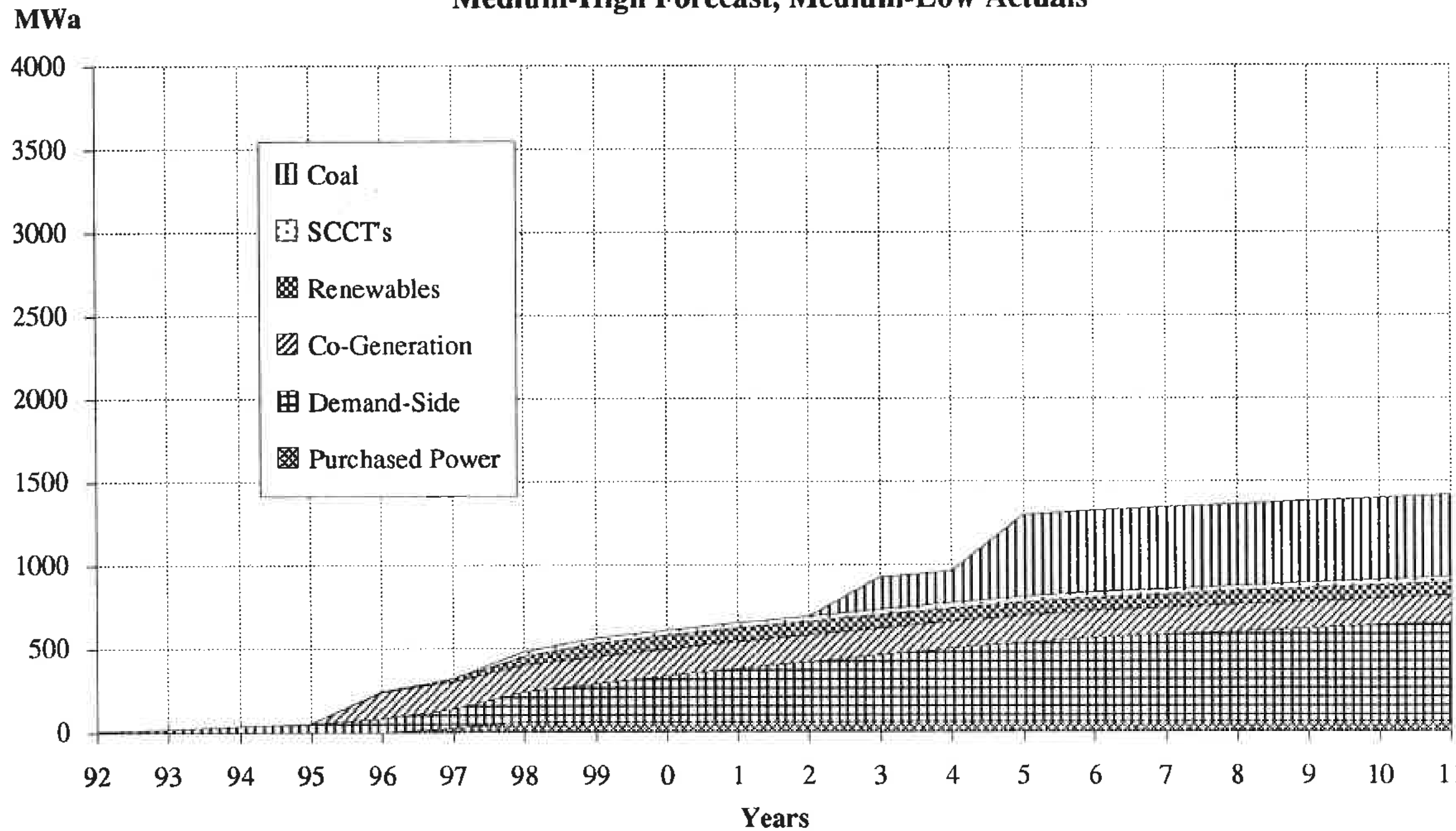
Illustrative Plan

Medium-High Forecast, Medium-Low Actuals



KEY OUTPUTS

Med-High Forecast, Med-Low Actuals

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5182.5	5270.1	5359.7	5450.8	5544.1	5637.7	5733.5	5825.2	5918.9	6012.9	6109.0	6206.7	6306.5	6406.7	6509.1	6613.2	6719.6	6826.3	6935.4
Total Conservation	4.5	9.9	20.7	35.5	55.5	82.8	115.9	178.7	226.6	272.9	316.1	356.9	396.3	435.0	470.6	498.3	517.1	535.9	553.8	571.2
System Load net of Conservation	5195.5	5172.7	5249.4	5324.2	5395.3	5461.3	5521.9	5554.9	5598.6	5646.0	5696.8	5752.1	5810.3	5871.6	5936.1	6010.9	6096.1	6183.7	6272.5	6364.2
Energy Sales after Conservation	4749.7	4728.9	4799.0	4867.4	4932.4	4992.7	5048.1	5078.3	5118.2	5161.6	5208.0	5258.6	5311.8	5367.8	5426.8	5495.1	5573.0	5653.1	5734.3	5818.2
Total Customers (000's)	1,207	1,218	1,240	1,259	1,274	1,290	1,309	1,327	1,344	1,361	1,377	1,397	1,416	1,437	1,458	1,478	1,500	1,524	1,551	1,576
Net Electric Plant (M$)	5944.2	6484.6	6745.4	6937.8	7140.8	7474.3	7910.3	8332.9	8922.7	9560.1	10404.1	11256.5	11955.6	12525.4	12813.9	13070.3	13285.7	13490.5	13705.9	13937.8
Net Conservation Assets	14.5	38.3	91.8	162.7	252.7	363.9	511.8	693.0	887.7	1086.8	1288.8	1491.3	1685.9	1868.7	2008.8	2097.5	2124.4	2118.2	2098.2	2069.5
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1911.1	1947.3	2130.6	2228.3	2306.0	2361.3	2475.8	2606.1	2784.6	2951.7	3112.9	3276.6	3585.6	3784.8	4166.2	4386.3	4622.7	4838.4	5091.9	5360.5
Real	1911.1	1852.8	1928.8	1919.4	1889.9	1841.3	1837.0	1839.8	1870.4	1886.5	1892.9	1895.8	1973.9	1982.5	2076.4	2080.0	2085.7	2077.1	2079.9	2083.3
NPV (9.54% discount rate)	26847.3																			
Average Growth																				
Nominal	5.58%																			
Real	0.46%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	46.9	50.7	52.3	53.4	53.8	56.0	58.6	62.1	65.1	68.2	71.1	77.1	80.3	87.6	91.1	94.7	97.4	101.4	105.2
Real	45.9	44.6	45.9	45.0	43.7	42.0	41.5	41.4	41.7	41.6	41.5	41.2	42.4	42.0	43.7	43.2	42.7	41.8	41.4	40.9
Average Growth																				
Nominal	4.46%																			
Real	-0.61%																			
Average Customer Bill ($)																				
Nominal	1584.0	1598.4	1718.1	1769.8	1810.5	1830.2	1891.8	1964.6	2071.6	2169.6	2260.3	2345.3	2531.9	2634.2	2857.3	2967.9	3081.4	3174.8	3284.1	3401.5
Real	1584.0	1520.8	1555.4	1524.4	1483.8	1427.2	1403.6	1387.0	1391.5	1386.6	1374.5	1356.9	1393.8	1379.8	1424.0	1407.4	1390.3	1362.9	1341.4	1322.0
NPV (9.54% discount rate)	19936.3																			
Customer Cost (M$)	2.8	2.8	3.6	4.2	4.8	3.1	3.2	3.6	3.3	1.9	0.9	-0.8	-1.2	-0.2	9.4	17.0	37.8	60.2	102.6	129.1
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	0.9	1.4	1.8	2.2	2.5	2.9	3.2	3.4	3.5	3.4	3.3	3.2	4.2	5.9	9.8	15.9	26.4	39.6
NPV (9.54% discount rate)	36.5																			
Energy Services Charge (M$)	0.9	2.4	6.4	11.9	19.5	29.0	43.3	61.7	82.2	104.0	126.9	150.8	175.2	200.7	225.7	247.9	251.3	249.8	247.7	243.4
NPV (9.54% discount rate)	748.0																			
Total Resource Cost (M$)																				
Nominal	1912.2	1950.2	2137.9	2241.6	2327.4	2392.5	2521.6	2670.6	2870.0	3059.1	3243.3	3430.7	3764.1	3988.7	4396.2	4640.1	4883.7	5104.2	5366.0	5643.5
Real	1912.2	1855.6	1935.5	1930.9	1907.5	1865.7	1870.9	1885.4	1927.8	1955.1	1972.2	1985.0	2072.2	2089.3	2191.0	2200.3	2203.5	2191.2	2191.8	2193.3
NPV (9.54% discount rate)	27631.8																			
Average Growth																				
Nominal	5.86%																			
Real	0.72%																			
Mills / KWh																				
Nominal	45.9	46.9	50.7	52.2	53.3	53.7	55.9	58.2	61.5	64.4	67.4	70.1	75.7	78.8	85.7	89.0	92.2	94.6	98.2	101.6
Real	45.9	44.6	45.9	45.0	43.7	41.9	41.4	41.1	41.3	41.1	41.0	40.6	41.7	41.3	42.7	42.2	41.6	40.6	40.1	39.5
Average Growth																				
Nominal	4.27%																			
Real	-0.79%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/Medium Low Actual

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,183	5,270	5,360	5,451	5,544	5,638	5,734	5,825	5,919	6,013	6,109	6,207	6,307	6,407	6,509	6,613	6,720	6,826	6,935	7,046
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,277	6,265	6,360	6,455	6,572	6,674	6,772	6,811	6,890	6,959	7,055	7,130	7,133	7,161	7,231	7,249	7,355	7,418	7,518	7,629
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	2	5	11	17	25	32	37	45	53	61	69	76	84	91	97	104	110	117	124	131
D.S. Options (1)	8	15	25	38	58	84	142	182	220	255	288	320	351	380	401	413	426	437	447	458
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)							11	45	45	45	45	45	45	45	45	45	45	45	45	45
Wind-Pilot (1)					5	22	38	38	38	38	38	38	38	38	38	38	38	38	38	38
CoGen (1)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Large CT (1)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Wyodak 2 (1)												192	191	192	193	192	191	192	193	192
Hunter 4 (1)														300	300	301	299	300	300	301
Wind (1) C																				
total	6,694	6,778	7,011	7,031	7,138	7,142	7,393	7,403	7,523	7,523	7,605	7,765	7,853	8,124	8,163	8,145	8,197	8,155	8,152	8,103
Balance	417	513	651	576	567	469	622	592	633	564	550	635	721	963	932	896	842	737	634	473

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/Medium Low Actual

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,731	6,845	6,962	7,080	7,201	7,323	7,447	7,566	7,687	7,810	7,935	8,062	8,191	8,322	8,455	8,590	8,727	8,867	9,009	9,153
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,008	8,098	8,215	8,337	8,360	8,482	8,606	8,725	8,796	8,919	9,044	9,171	9,100	9,131	9,256	9,191	9,328	9,468	9,535	9,679
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	2	7	15	24	35	45	53	65	76	88	100	111	123	134	144	155	166	177	188	199
D.S. Options (1)	9	19	33	53	87	132	229	298	364	425	479	532	584	632	667	687	707	726	744	760
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	50	50	50	50	50	50	50	50	50	50	50	50
Wind-Pilot (1)						16	39	39	39	39	39	39	39	39	39	39	39	39	39	39
CoGen (1)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Large CT (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)												256	256	256	256	256	256	256	256	256
Hunter 4 (1)														400	400	400	400	400	400	400
Wind (1) C																				
total	9,475	9,857	10,153	10,361	10,503	10,458	11,149	11,291	11,340	11,404	11,480	11,797	11,824	12,288	12,205	12,254	12,241	12,271	12,134	12,180
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,328	1,331	1,382	1,390	1,390	1,390	1,390	1,428	1,428	1,488	1,488	1,488	1,488	1,488	1,488	1,488
Balance	167	459	638	724	815	645	1,161	1,176	1,154	1,095	1,046	1,198	1,296	1,669	1,461	1,575	1,424	1,315	1,111	1,013
(Reserve+Balance)/Requirement	18%	22%	24%	24%	26%	23%	30%	29%	29%	28%	27%	29%	30%	35%	32%	33%	31%	30%	27%	26%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/Medium Low Actual

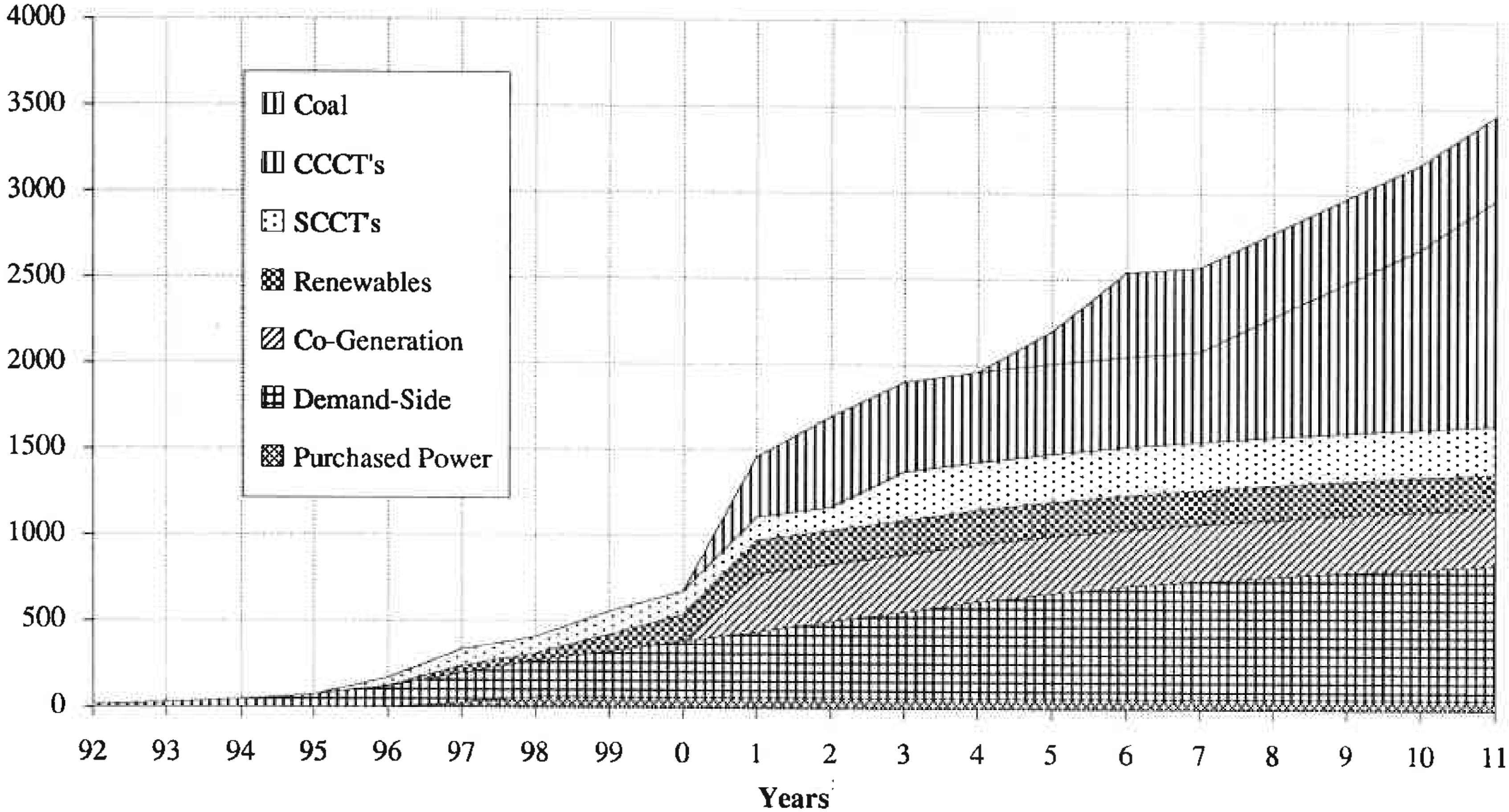
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	6,277	6,384	6,492	6,603	6,715	6,829	6,945	7,056	7,169	7,283
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459
total	8,090	7,997	8,109	8,222	8,429	8,508	8,624	8,595	8,723	8,742
Resources										
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130
D.S. Lost Opportunities (1)	2	5	11	17	24	32	36	44	52	60
D.S. Options (1)	8	15	26	41	70	108	188	245	300	352
BPA Entitlement (1)										
Geothermal-Pilot (1)								50	50	50
Wind-Pilot (1)						10	25	25	25	25
CoGen (1)					94	94	94	94	94	94
CoGen (2)					94	94	94	94	94	94
Large CT (1)							156	156	156	156
Wyodak 2 (1)										
Hunter 4 (1)										
Wind (1) C										
total	9,780	9,827	10,143	10,285	10,339	10,275	10,490	10,582	10,654	10,706
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,300	1,328	1,331	1,382	1,390	1,390	1,390
Balance	390	530	733	764	582	436	484	597	541	573
(Reserve+Balance)/Requirement	21%	23%	25%	25%	23%	21%	22%	23%	22%	22%

Summer Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	7,400	7,518	7,638	7,760	7,885	8,011	8,139	8,269	8,401	8,535
Firm Sales	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,859	8,977	8,897	8,911	9,036	8,962	9,090	9,145	9,277	9,411
Resources										
Existing Generation	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	68	75	83	90	97	104	111	119	126	133
D.S. Options (1)	401	449	497	540	572	590	608	625	642	658
BPA Entitlement (1)										
Geothermal-Pilot (1)	50	50	50	50	50	50	50	50	50	50
Wind-Pilot (1)	25	25	25	25	25	25	25	25	25	25
CoGen (1)	94	94	94	94	94	94	94	94	94	94
CoGen (2)	94	94	94	94	94	94	94	94	94	94
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)		256	256	256	256	256	256	256	256	256
Hunter 4 (1)				400	400	400	400	400	400	400
Wind (1) C										
total	10,770	11,044	11,100	11,555	11,479	11,559	11,591	11,616	11,489	11,514
Reserve Requirement										
Total Company Reserve	1,390	1,428	1,428	1,488	1,488.	1,488	1,488	1,488	1,488	1,488
Balance	521	639	775	1,156	955	1,110	1,013	983	724	615
(Reserve+Balance)/Requirement	22%	23%	25%	30%	27%	29%	28%	27%	24%	22%

PacifiCorp - RAMPP 2

Illustrative Plan

Medium Low Forecast, Medium High Actuals



KEY OUTPUTS

Med-Low Forecast, Med-High Actual

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.3	5585.5	5753.0	5925.6	6104.0	6286.5	6475.1	6716.0	6948.5	7182.4	7414.8	7648.1	7871.4	8088.0	8328.4	8550.4	8763.3	8970.4	9177.1
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	208.3	264.7	322.4	381.3	441.2	500.5	558.4	608.9	651.1	682.6	709.9	735.2	759.2
System Load net of Conservation	5195.5	5410.0	5559.0	5706.9	5850.1	5984.2	6112.5	6266.8	6451.3	6626.0	6801.2	6973.6	7147.6	7313.1	7479.0	7677.3	7867.8	8053.5	8235.3	8417.9
Energy Sales after Conservation	4749.7	4945.8	5082.1	5217.3	5348.2	5470.8	5588.1	5729.1	5897.8	6057.5	6217.6	6375.3	6534.3	6685.6	6837.3	7018.6	7192.7	7362.5	7528.7	7695.6
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6497.1	6804.6	7243.8	7679.1	8078.5	8620.9	9440.7	10376.4	11197.6	12215.4	13358.1	14307.2	15211.5	15912.8	16456.2	17088.1	17820.5	18457.5	18836.4
Net Conservation Assets	16.1	50.8	106.1	185.7	301.0	455.6	699.7	981.5	1264.9	1530.3	1766.8	1981.9	2183.3	2372.8	2534.0	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1909.9	1983.6	2169.6	2279.3	2385.4	2587.3	2765.0	2924.0	3198.3	3461.3	3844.6	4156.7	4594.1	4899.4	5391.5	5905.7	6369.7	6832.7	7369.0	7956.0
Real	1909.9	1887.3	1964.2	1963.3	1955.0	2017.6	2051.5	2064.2	2148.3	2212.2	2337.9	2405.0	2529.1	2566.3	2687.0	2800.5	2873.9	2933.2	3009.9	3092.0
NPV (9.54% discount rate)	31665.5																			
Average Growth																				
Nominal	7.80%																			
Real	2.57%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.7	48.7	49.9	50.9	53.8	56.5	58.3	61.9	65.1	70.6	74.4	80.3	83.4	90.0	96.1	101.1	105.7	111.7	118.0
Real	45.9	43.4	44.1	43.0	41.7	42.0	41.9	41.1	41.6	41.6	42.9	43.1	44.2	43.7	44.9	45.5	45.6	45.4	45.6	45.9
Average Growth																				
Nominal	5.10%																			
Real	0.00%																			
Average Customer Bill ($)																				
Nominal	1565.5	1588.8	1711.1	1769.0	1810.3	1913.7	1994.7	2062.3	2202.4	2331.2	2533.4	2675.5	2890.6	3018.7	3257.9	3505.1	3713.9	3909.6	4131.3	4371.2
Real	1565.5	1511.7	1549.0	1523.7	1483.6	1492.3	1480.0	1455.9	1479.4	1489.9	1540.5	1548.0	1591.3	1581.2	1623.7	1662.1	1675.7	1678.3	1687.5	1698.8
NPV (9.54% discount rate)	21557.8																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1911.2	1987.8	2178.6	2295.2	2411.2	2626.1	2824.6	3008.3	3308.8	3599.2	4010.9	4353.4	4823.1	5162.7	5690.4	6234.8	6710.8	7187.3	7736.3	8336.3
Real	1911.2	1891.3	1972.3	1977.1	1976.2	2047.8	2095.7	2123.7	2222.5	2300.3	2439.0	2518.8	2655.2	2704.2	2836.0	2956.5	3027.8	3085.4	3160.0	3239.8
NPV (9.54% discount rate)	32682.7																			
Average Growth																				
Nominal	8.06%																			
Real	2.82%																			
Mills / KWh																				
Nominal	45.9	45.6	48.7	49.8	50.8	53.6	56.1	58.0	61.5	64.5	69.7	73.3	78.7	81.7	87.9	93.5	98.0	102.1	107.7	113.4
Real	45.9	43.4	44.1	42.9	41.6	41.8	41.6	41.0	41.3	41.2	42.4	42.4	43.4	42.8	43.8	44.3	44.2	43.8	44.0	44.1
Average Growth																				
Nominal	4.88%																			
Real	-0.21%																			

PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
Medium Low Forecast/Medium High Actual

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	5,423	5,585	5,753	5,926	6,104	6,286	6,475	6,716	6,948	7,182
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946
total	6,517	6,581	6,753	6,930	7,132	7,322	7,513	7,701	7,920	8,129
Resources										
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316
Firm Purchases	612	632	675	682	554	535	566	558	556	551
D.S. Lost Opportunities (1)	3	7	13	22	33	44	58	69	80	91
D.S. Options (1)	10	19	33	54	87	130	150	195	242	290
BPA Entitlement (1)						26	65	65	65	65
Geothermal-Pilot (1)								45	90	135
Wind-Pilot (1)					5	15	15	22	38	38
Large CT (1) C										
Large CT (Jul) (1)					16	31	31	31	31	31
Large CT (Jul) (2)					16	31	31	31	31	31
Large CT (Jul) (3)					16	31	31	31	31	31
Large CT (Jul) (4) C										
Wind (1)						30	30	30	30	30
Medium CT (1)								20	20	20
Medium CT (2)								20	20	20
CoGen (1)										80
CoGen (2)										80
CoGen 1 (1)										85
CoGen 1 (2)										85
Large CC CT (1)										175
Large CC CT (2)										175
Wyodak 2 (1)										
Large CC CT (3)										
Hunter 4 (1)										
Large CT (2)										
Large CT (3)										
Large CT (4)										
Medium CT (3)										
Large CT (5)										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
total	6,697	6,784	7,021	7,051	7,063	7,157	7,322	7,398	7,590	8,330
Balance	180	203	268	121	-69	-166	-192	-303	-329	201

Average Megawatts	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	7,415	7,648	7,871	8,088	8,328	8,550	8,763	8,970	9,177	9,399
Firm Sales	946	923	826	754	722	635	635	591	583	583
total	8,361	8,571	8,697	8,842	9,051	9,186	9,398	9,562	9,760	9,982
Resources										
Existing Generation	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	102	112	122	133	143	153	163	174	184	193
D.S. Options (1)	339	389	436	476	508	530	546	561	575	588
BPA Entitlement (1)	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)	38	38	38	38	38	38	38	38	38	38
Large CT (1) C										
Large CT (Jul) (1)	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (2)	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (3)	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (4) C										
Wind (1)	30	30	30	30	30	30	30	30	30	30
Medium CT (1)	20	20	20	20	20	20	20	20	20	20
Medium CT (2)	20	20	20	20	20	20	20	20	20	20
CoGen (1)	80	80	80	80	80	80	80	80	80	80
CoGen (2)	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)	85	85	85	85	85	85	85	85	85	85
Large CC CT (1)	175	175	175	175	175	175	175	175	175	175
Large CC CT (2)	175	175	175	175	175	175	175	175	175	175
Wyodak 2 (1)				192	192	192	192	192	192	192
Large CC CT (3)	175	175	175	175	175	175	175	175	175	175
Hunter 4 (1)					300	300	300	300	300	300
Large CT (2)		31	31	31	31	31	31	31	31	31
Large CT (3)		31	31	31	31	31	31	31	31	31
Large CT (4)		31	31	31	31	31	31	31	31	31
Medium CT (3)		20	20	20	20	20	20	20	20	20
Large CT (5)		31	31	31	31	31	31	31	31	31
Large CC CT							175	175	175	175
Large CC CT								175	175	175
Large CC CT									175	175
Large CC CT										175
Large CC CT (Jul)										88
total	8,607	8,739	8,848	9,024	9,378	9,372	9,610	9,748	9,927	10,145
Balance	246	168	151	182	327	186	212	186	167	163

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PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
Medium Low Forecast/Medium High Actual

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,267	7,485	7,709	7,940	8,179	8,424	8,738	9,039	9,344	9,647	9,950	10,240	10,522	10,835	11,124	11,400	11,671	11,939	12,228
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,520	8,738	8,966	9,099	9,338	9,583	9,897	10,148	10,453	10,756	11,059	11,149	11,331	11,636	11,725	12,001	12,272	12,465	12,754
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	17	30	46	62	83	99	116	132	148	164	180	196	212	229	246	263	279	295
D.S. Options (1)	11	25	46	78	134	207	244	322	403	487	572	657	739	806	859	894	922	947	970	991
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind Pilot (1)						16	16	16	39	39	39	39	39	39	39	39	39	39	39	39
Large CT (1) C																				
Large CT (Jul) (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (2)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (3)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (4) C																				
Wind (1)						32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (2)								100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (1)										94	94	94	94	94	94	94	94	94	94	94
CoGen (2)										94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)										100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)										100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)										250	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)														256	256	256	256	256	256	256
Large CC CT (3)											250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)															400	400	400	400	400	400
Large CT (2)												156	156	156	156	156	156	156	156	156
Large CT (3)												156	156	156	156	156	156	156	156	156
Large CT (4)												156	156	156	156	156	156	156	156	156
Medium CT (3)												100	100	100	100	100	100	100	100	100
Large CT (5)												156	156	156	156	156	156	156	156	156
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT (Jul)																				250
total	9,478	9,865	10,169	10,392	10,373	10,861	11,326	11,682	11,824	12,854	13,214	14,036	14,098	14,442	14,783	14,852	15,103	15,396	15,519	15,824
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,300	1,300	1,377	1,402	1,439	1,450	1,591	1,629	1,737	1,737	1,776	1,836	1,836	1,873	1,911	1,948	1,986
Balance	-154	45	131	126	-26	146	341	346	225	809	830	1,240	1,212	1,335	1,311	1,292	1,229	1,214	1,106	1,084
(Reserve+Balance)/Requirement	14%	16%	16%	16%	14%	16%	18%	18%	17%	23%	23%	27%	26%	27%	27%	27%	26%	25%	25%	24%

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PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
Medium Low Forecast/Medium High Actual

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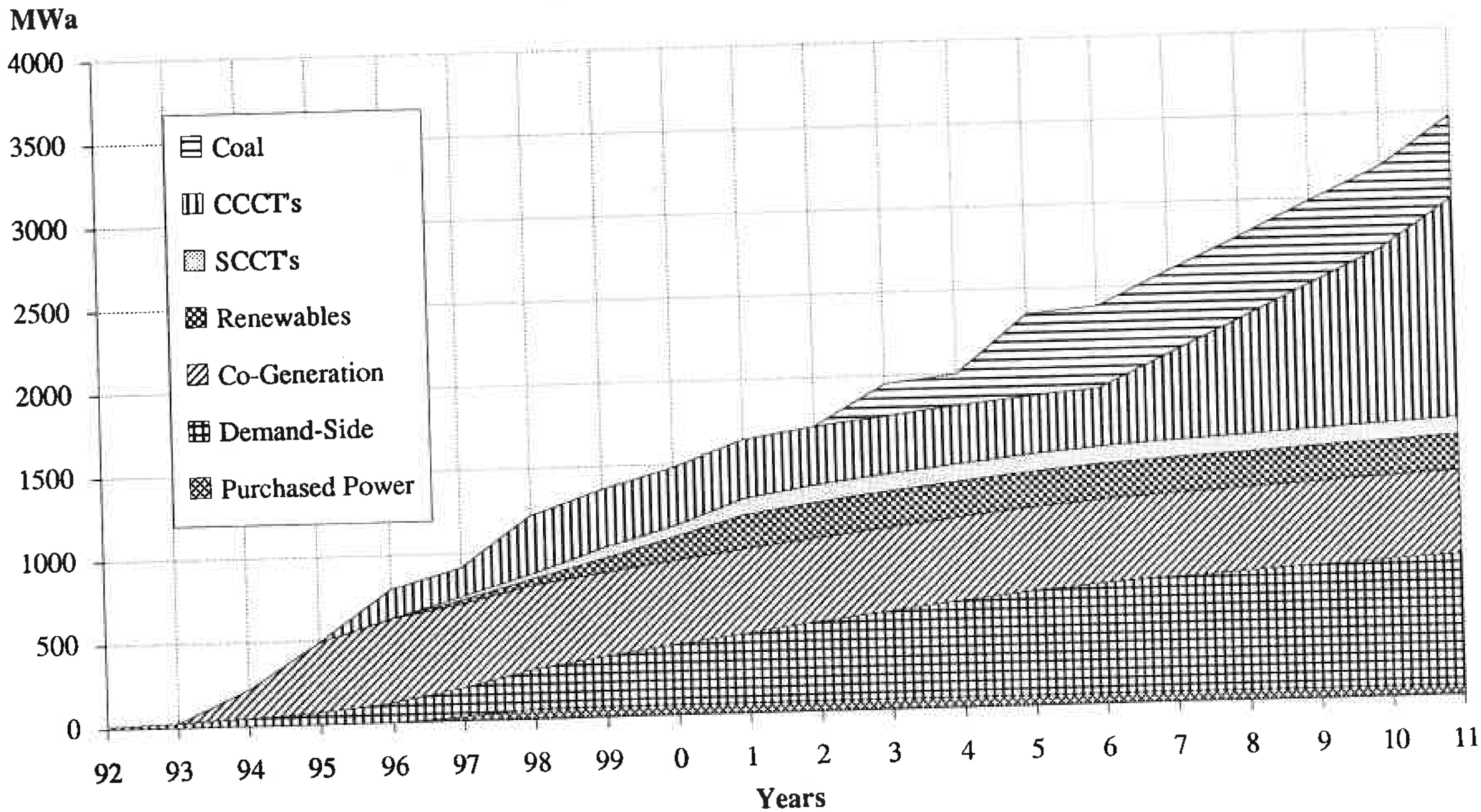
Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	6,589	6,787	6,990	7,200	7,416	7,638	7,868	8,160	8,442	8,727
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459
total	8,402	8,400	8,607	8,819	9,130	9,317	9,547	9,699	9,996	10,186
Resources										
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130
D.S. Lost Opportunities (1)	3	7	12	21	33	44	58	69	80	91
D.S. Options (1)	9	19	34	59	105	166	197	260	325	390
BPA Entitlement (1)										
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						10	10	10	25	25
Large CT (1) C										
Large CT (Jul) (1)					156	156	156	156	156	156
Large CT (Jul) (2)					156	156	156	156	156	156
Large CT (Jul) (3)					156	156	156	156	156	156
Large CT (Jul) (4) C										
Wind (1)						20	20	20	20	20
Medium CT (1)								100	100	100
Medium CT (2)								100	100	100
CoGen (1)										94
CoGen (2)										94
CoGen 1 (1)										100
CoGen 1 (2)										100
Large CC CT (1)										250
Large CC CT (2)										250
Wyodak 2 (1)										
Large CC CT (3)										
Hunter 4 (1)										
Large CT (2)										
Large CT (3)										
Large CT (4)										
Medium CT (3)										
Large CT (5)										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
total	9,782	9,832	10,153	10,307	10,662	10,644	10,649	10,951	11,100	12,107
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,300	1,300	1,377	1,402	1,439	1,450	1,591
Balance	80	133	246	188	232	-50	-299	-188	-346	330
(Reserve+Balance)/Requirement	16%	17%	18%	17%	17%	14%	12%	13%	11%	19%

Summer Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	9,010	9,293	9,563	9,827	10,120	10,389	10,647	10,900	11,151	11,421
Firm Sales	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	10,469	10,752	10,822	10,978	11,271	11,340	11,598	11,776	12,027	12,297
Resources										
Existing Generation	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	102	112	123	134	145	156	167	178	188	198
D.S. Options (1)	457	524	590	648	694	723	748	770	790	809
BPA Entitlement (1)										
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	25	25	25	25	25	25	25	25	25	25
Large CT (1) C										
Large CT (Jul) (1)	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (2)	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (3)	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (4) C										
Wind (1)	20	20	20	20	20	20	20	20	20	20
Medium CT (1)	100	100	100	100	100	100	100	100	100	100
Medium CT (2)	100	100	100	100	100	100	100	100	100	100
CoGen (1)	94	94	94	94	94	94	94	94	94	94
CoGen (2)	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Large CC CT (2)	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)				256	256	256	256	256	256	256
Large CC CT (3)	250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)					400	400	400	400	400	400
Large CT (2)		156	156	156	156	156	156	156	156	156
Large CT (3)		156	156	156	156	156	156	156	156	156
Large CT (4)		156	156	156	156	156	156	156	156	156
Medium CT (3)		100	100	100	100	100	100	100	100	100
Large CT (5)		156	156	156	156	156	156	156	156	156
Large CC CT							250	250	250	250
Large CC CT								250	250	250
Large CC CT									250	250
Large CC CT										250
Large CC CT (Jul)										250
total	12,442	13,200	13,284	13,614	13,955	14,050	14,341	14,625	14,756	15,287
Reserve Requirement										
Total Company Reserve	1,629	1,737	1,737	1,776	1,836	1,836	1,873	1,911	1,948	1,986
Balance	345	717	724	860	848	874	870	909	781	1,005
(Reserve+Balance)/Requirement	19%	23%	23%	24%	24%	24%	24%	24%	23%	24%

PacifiCorp - RAMPP 2

Illustrative Plan

High Forecast, Medium-High Actuals



KEY OUTPUTS

High Forecast / Medium High actual

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5423.3	5585.5	5753.0	5925.6	6104.0	6286.5	6475.1	6716.0	6948.5	7182.4	7414.8	7648.1	7871.4	8088.0	8328.4	8550.4	8763.3	8970.4	9177.1
Total Conservation	4.5	13.3	26.4	46.1	75.5	119.8	173.9	237.1	299.4	360.0	417.1	471.6	524.5	576.5	621.3	659.1	685.2	710.3	734.5	758.6
System Load net of Conservation	5195.5	5410.0	5559.0	5706.9	5850.1	5984.2	6112.5	6238.0	6416.6	6588.5	6765.3	6943.2	7123.6	7294.9	7466.7	7669.3	7865.2	8053.0	8236.0	8418.5
Energy Sales after Conservation	4749.7	4945.8	5082.1	5217.3	5348.2	5470.8	5588.1	5702.8	5866.1	6023.2	6184.9	6347.5	6512.3	6669.0	6826.0	7011.3	7190.3	7362.1	7529.3	7696.2
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5938.6	6510.5	6846.1	7172.3	7584.5	8069.9	8681.2	9340.5	10187.5	11081.8	12000.4	12849.8	13577.9	14306.9	14936.5	15609.4	16271.5	17033.9	17700.9	18109.9
Net Conservation Assets	8.9	44.1	99.9	180.0	295.8	450.8	695.4	977.6	1261.5	1527.4	1764.5	1980.0	2181.9	2371.8	2533.6	2612.5	2605.4	2598.9	2583.5	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.8	1982.6	2168.7	2301.1	2416.9	2585.6	2759.7	2974.1	3239.5	3483.7	3805.3	4076.1	4488.1	4788.8	5285.6	5677.0	6198.7	6669.3	7210.2	7797.2
Real	1910.8	1886.4	1963.4	1982.1	1980.9	2016.2	2047.6	2099.6	2176.0	2226.4	2314.0	2358.4	2470.7	2508.4	2634.3	2692.0	2796.8	2863.1	2945.1	3030.3
NPV (9.54% discount rate)	31419.1																			
Average Growth																				
Nominal	7.68%																			
Real	2.46%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.6	48.7	50.3	51.6	53.8	56.4	59.5	63.0	65.8	70.2	73.3	78.7	81.7	88.4	92.4	98.4	103.1	109.3	115.7
Real	45.9	43.4	44.1	43.4	42.3	42.0	41.8	42.0	42.3	42.1	42.7	42.4	43.3	42.8	44.1	43.8	44.4	44.3	44.7	44.9
Average Growth																				
Nominal	4.98%																			
Real	-0.11%																			
Average Customer Bill ($)																				
Nominal	1566.2	1588.0	1710.3	1785.8	1834.2	1912.4	1990.9	2097.7	2230.7	2346.2	2507.4	2623.6	2823.9	2950.6	3193.9	3369.3	3614.2	3816.1	4042.3	4283.9
Real	1566.2	1510.9	1548.4	1538.3	1503.3	1491.3	1477.2	1480.9	1498.4	1499.5	1524.8	1518.0	1554.6	1545.5	1591.8	1597.7	1630.7	1638.2	1651.1	1664.9
NPV (9.54% discount rate)	21421.7																			
Customer Cost (M$)	2.8	3.3	3.3	3.2	4.1	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.6	1.0	1.3	1.7	1.6	1.1	0.5	0.0	-0.2	0.1	0.9	2.2	3.8	7.1	11.6	18.9	28.2	40.5	55.8
NPV (9.54% discount rate)	41.0																			
Energy Services Charge (M$)	1.0	3.5	8.0	14.6	24.1	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	976.3																			
Total Resource Cost (M$)																				
Nominal	1912.1	1986.8	2177.7	2317.0	2442.8	2624.3	2819.3	3058.4	3349.9	3621.5	3971.5	4272.8	4717.0	5052.1	5584.5	6006.1	6539.7	7023.9	7577.6	8177.5
Real	1912.1	1890.3	1971.5	1995.8	2002.0	2046.4	2091.8	2159.1	2250.2	2314.6	2415.1	2472.2	2596.8	2646.3	2783.2	2848.1	2950.6	3015.3	3095.1	3178.1
NPV (9.54% discount rate)	32436.3																			
Average Growth																				
Nominal	7.95%																			
Real	2.71%																			
Mills / KWh																				
Nominal	45.9	45.6	48.7	50.3	51.5	53.5	56.0	59.0	62.3	64.9	69.0	72.0	77.0	79.9	86.2	90.0	95.5	99.8	105.5	111.3
Real	45.9	43.4	44.1	43.3	42.2	41.7	41.6	41.6	41.8	41.5	42.0	41.6	42.4	41.9	43.0	42.7	43.1	42.8	43.1	43.2
Average Growth																				
Nominal	4.77%																			
Real	-0.32%																			

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PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
High Forecast/Medium High Actual

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,423	5,585	5,753	5,926	6,104	6,286	6,475	6,716	6,948	7,182	7,415	7,648	7,871	8,088	8,328	8,550	8,763	8,970	9,177	9,399
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,517	6,581	6,753	6,930	7,132	7,322	7,513	7,701	7,920	8,129	8,361	8,571	8,697	8,842	9,051	9,186	9,398	9,562	9,760	9,982
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	3	7	13	22	33	44	54	66	78	89	101	112	124	134	144	154	165	175	185	195
D.S. Options (1)	10	19	33	54	87	130	183	233	282	328	371	412	453	487	515	531	546	560	574	587
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)				85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 2 (1)			85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen 2 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85.	85	85
Large CC CT (1)					175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Small CT (1)						8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (1)						4	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)						4	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (3)						4	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Large CC CT (2)							175	175	175	175	175	175	175	175	175	175	175	175	175	175
Wyodak 2 (1)												192	191	192	193	192	191	192	193	192
Large CT (1)								31	31	31	31	31	31	31	31	31	31	31	31	31
Hunter 4 (1)														300	300	301	299	300	300	301
Small CT (Jul) (4)										4	8	8	8	8	8	8	8	8	8	8
Large CT (2)										31	31	31	31	31	31	31	31	31	31	31
Large CC CT																175	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Large CC CT																				175
Large CC CT (Jul)																				88
total	6,697	6,784	7,191	7,466	7,690	7,736	8,131	8,203	8,396	8,507	8,616	8,789	8,890	9,172	9,220	9,384	9,617	9,758	9,936	10,157
Balance	180	203	438	537	558	414	618	501	476	378	255	218	193	330	170	198	218	196	176	175

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L&R - He/MHa 4/2

PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
High Forecast/Medium High Actual

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,055	7,267	7,485	7,709	7,940	8,179	8,424	8,738	9,039	9,344	9,647	9,950	10,240	10,522	10,835	11,124	11,400	11,671	11,939	12,228
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,332	8,520	8,738	8,966	9,099	9,338	9,583	9,897	10,148	10,453	10,756	11,059	11,149	11,331	11,636	11,725	12,001	12,272	12,465	12,754
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	4	9	17	30	46	62	76	94	111	129	146	163	180	197	213	230	246	263	280	297
D.S. Options (1)	12	25	46	77	132	206	297	384	468	545	617	685	753	810	856	883	908	931	954	977
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 2 (1)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen 2 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Small CT (1)						40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)							40	40	40	40	40	40	40	40	40	40	40	40	40	40
Large CC CT (2)							250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)												256	256	256	256	256	256	256	256	256
Large CT (1)								156	156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)														400	400	400	400	400	400	400
Small CT (Jul) (4)											40	40	40	40	40	40	40	40	40	40
Large CT (2)										156	156	156	156	156	156	156	156	156	156	156
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT (Jul)																				
total	9,480	9,866	10,369	10,879	11,209	11,239	12,145	12,467	12,605	12,913	13,066	13,406	13,455	13,933	13,867	14,177	14,424	14,715	14,839	15,147
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,330	1,373	1,426	1,434	1,518	1,549	1,559	1,592	1,600	1,639	1,639	1,699	1,699	1,736	1,774	1,811	1,849	1,886
Balance	-152	46	301	540	684	467	1,044	1,021	898	868	710	708	667	903	532	716	650	633	526	507
(Reserve+Balance)/Requirement	14%	16%	19%	21%	23%	20%	27%	26%	24%	24%	21%	21%	21%	23%	19%	21%	20%	20%	19%	19%

L&R - He/MHa 4/2

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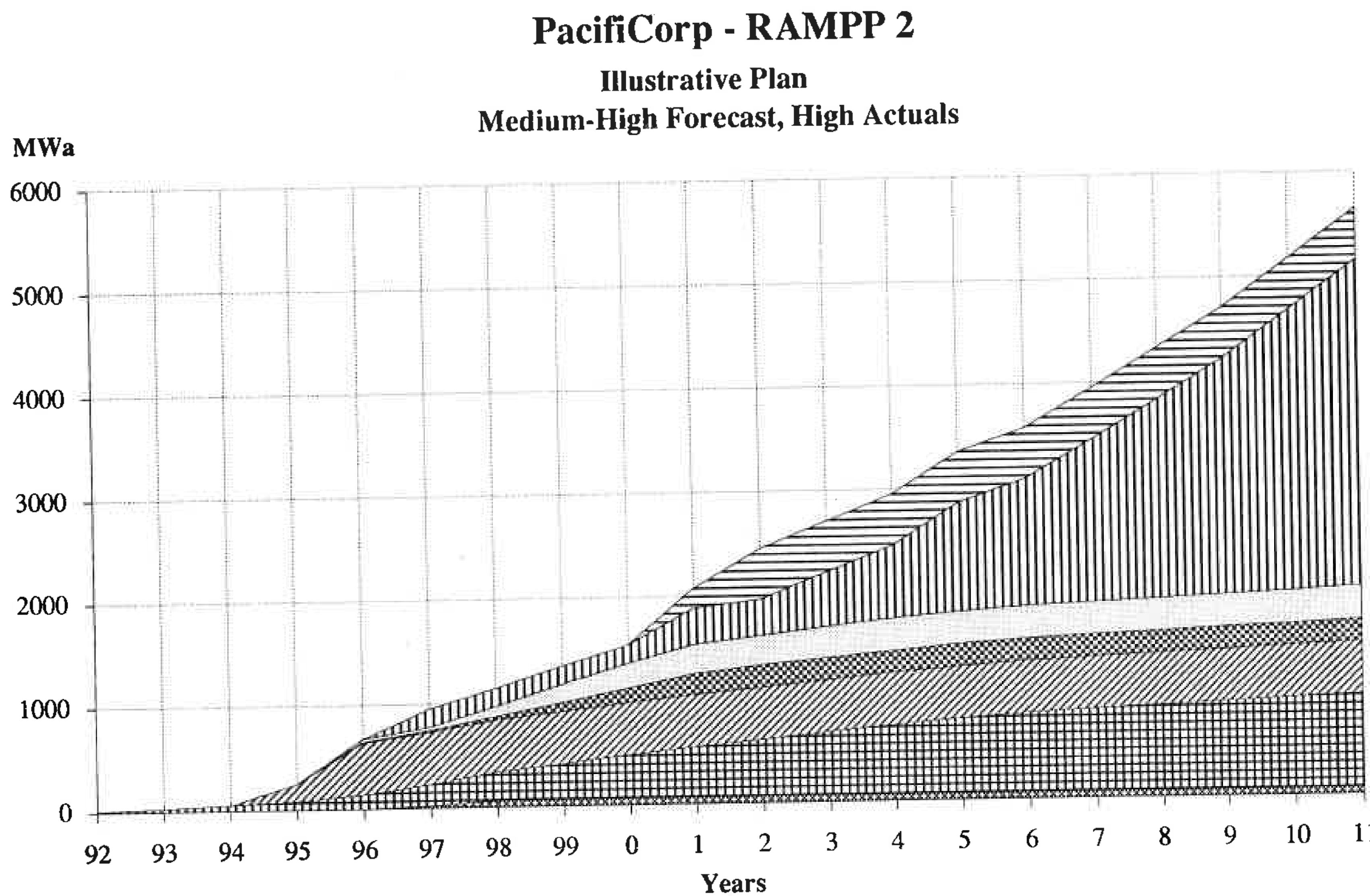
PacifiCorp Electric Operations
4/1 RIM - Medium Low Forecast
High Forecast/Medium High Actual

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	6,589	6,787	6,990	7,200	7,416	7,638	7,868	8,160	8,442	8,727
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459
total	8,402	8,400	8,607	8,819	9,130	9,317	9,547	9,699	9,996	10,186
Resources										
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130
D.S. Lost Opportunities (1)	3	7	12	21	32	42	52	63	75	86
D.S. Options (1)	10	20	36	61	108	171	249	322	394	462
CoGen (1)				94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94
CoGen 1 (1)			100	100	100	100	100	100	100	100
CoGen 1 (2)				100	100	100	100	100	100	100
CoGen 2 (1)			100	100	100	100	100	100	100	100
BPA Entitlement (1)										
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						10	25	25	35	45
CoGen 2 (2)					100	100	100	100	100	100
Large CC CT (1)					250	250	250	250	250	250
Small CT (1)						40	40	40	40	40
Small CT (Jul) (1)						40	40	40	40	40
Small CT (Jul) (2)						40	40	40	40	40
Small CT (Jul) (3)						40	40	40	40	40
Large CC CT (2)							250	250	250	250
Wyodak 2 (1)										
Large CT (1)								156	156	156
Hunter 4 (1)										
Small CT (Jul) (4)										40
Large CT (2)										156
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
total	9,783	9,834	10,355	10,797	11,035	11,159	11,470	11,738	11,890	12,218
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,330	1,373	1,426	1,434	1,518	1,549	1,559	1,592
Balance	81	134	418	605	479	408	406	490	336	440
(Reserve+Balance)/Requirement	16%	17%	20%	22%	21%	20%	20%	21%	19%	20%

Summer Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	9,010	9,293	9,563	9,827	10,120	10,389	10,647	10,900	11,151	11,421
Firm Sales	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	10.469	10,752	10,822	10,978	11,271	11,340	11,598	11,776	12,027	12,297
Resources										
Existing Generation	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	98	109	120	131	141	152	162	173	184	195
D.S. Options (1)	527	591	654	707	750	775	798	820	841	863
CoGen (1)	94	94	94	94	94	94	94	94	94	94
CoGen (2)	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
CoGen 2 (1)	100	100	100	100	100	100	100	100	100	100
BPA Entitlement (1)										
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	55	55	55	55	55	55	55	55	55	55
CoGen 2 (2)	100	100	100	100	100	100	100	100	100	100
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Small CT (1)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)	40	40	40	40	40	40	40	40	40	40
Large CC CT (2)	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)		256	256	256	256	256	256	256	256	256
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)				400	400	400	400	400	400	400
Small CT (Jul) (4)	40	40	40	40	40	40	40	40	40	40
Large CT (2)	156	156	156	156	156	156	156	156	156	156
Large CC CT						250	250	250	250	250
Large CC CT							250	250	250	250
Large CC CT								250	250	250
Large CC CT									250	250
Large CC CT										250
Large CC CT (Jul)										250
total	12,312	12,605	12,680	13,149	13,087	13,427	13,717	14,001	14,133	14,667
Reserve Requirement										
Total Company Reserve	1,600	1,639	1,639	1,699	1,699	1,736	1,774	1,811	1,849	1,886
Balance	243	214	219	472	118	351	345	414	258	485
(Reserve+Balance)/Requirement	18%	17%	17%	20%	16%	18%	18%	19%	18%	19%


PacifiCorp - RAMPP 2
Illustrative Plan
Medium-High Forecast, High Actuals
MWa
6000
5000
4000
3000
2000
1000
0
92
93
94
95
96
97
98
99
0
1
2
3
4
5
6
7
8
9
10
11
Years

KEY OUTPUTS

Medium High Forecast / High Actual

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5534.8	5750.1	5974.4	6207.4	6450.1	6701.0	6962.3	7241.1	7531.8	7832.5	8146.0	8472.2	8812.3	9164.0	9530.9	9912.4	10310.2	10721.8	11150.9
Total Conservation	4.5	15.5	30.9	54.0	88.0	139.7	203.6	275.3	348.8	419.8	486.1	548.9	609.5	668.9	723.8	766.6	796.1	825.7	853.9	881.3
System Load net of Conservation	5195.5	5519.3	5719.2	5920.3	6119.4	6310.4	6497.4	6687.0	6892.3	7112.0	7346.4	7597.1	7862.6	8143.3	8440.2	8764.3	9116.2	9484.5	9867.9	10269.6
Energy Sales after Conservation	4749.7	5045.8	5228.5	5412.3	5594.3	5769.0	5939.9	6113.2	6300.9	6501.8	6716.1	6945.3	7188.0	7444.6	7716.1	8012.3	8334.0	8670.7	9021.2	9388.4
Total Customers (000's)	1,230	1,267	1,294	1,323	1,361	1,405	1,449	1,490	1,535	1,578	1,621	1,668	1,715	1,759	1,802	1,843	1,885	1,929	1,976	2,025
Net Electric Plant (M$)	5945.7	6503.9	6803.4	7138.6	7524.6	8104.2	9172.7	10561.7	12025.9	13279.5	14278.0	15149.6	16022.7	16979.4	17978.9	19095.5	20260.4	21416.6	22239.9	22581.5
Net Conservation Assets	16.1	57.5	119.6	208.6	335.3	504.7	794.1	1117.2	1442.1	1748.6	2025.5	2280.4	2520.9	2748.8	2911.2	3012.7	3012.4	3000.6	2980.9	2963.5
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1909.4	2000.9	2212.9	2340.9	2454.9	2673.4	2910.6	3193.5	3579.5	3980.4	4527.3	4995.3	5494.2	5959.3	6580.2	7211.7	7988.1	8749.2	9602.0	10619.8
Real	1909.4	1903.8	2003.4	2016.4	2012.0	2084.7	2159.6	2254.5	2404.4	2543.9	2753.1	2890.2	3024.6	3121.5	3279.4	3419.8	3604.1	3756.0	3922.0	4127.3
NPV (9.54% discount rate)	36067.2																			
Average Growth																				
Nominal	9.45%																			
Real	4.14%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.1	48.3	49.4	50.1	52.8	55.9	59.6	64.9	69.7	77.0	82.1	87.3	91.1	97.4	102.7	109.4	114.9	121.5	129.1
Real	45.9	43.0	43.7	42.5	41.1	41.1	41.5	42.1	43.6	44.5	46.8	47.5	48.0	47.7	48.5	48.7	49.4	49.3	49.6	50.2
Average Growth																				
Nominal	5.60%																			
Real	0.47%																			
Average Customer Bill ($)																				
Nominal	1552.3	1579.7	1709.7	1769.1	1803.7	1902.8	2008.8	2142.6	2331.8	2522.4	2792.4	2994.6	3204.1	3387.2	3651.1	3912.4	4238.6	4536.7	4858.5	5245.3
Real	1552.3	1503.1	1547.8	1523.8	1478.2	1483.8	1490.5	1512.6	1566.3	1612.1	1698.1	1732.6	1763.9	1774.2	1819.7	1855.2	1912.4	1947.6	1984.5	2038.5
NPV (9.54% discount rate)	22925.0																			
Customer Cost (M$)	2.8	3.6	3.6	3.9	5.0	0.0	-3.9	-4.8	-3.0	-1.0	4.3	9.6	14.8	18.0	33.4	47.5	75.2	103.8	133.2	167.5
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.7	1.0	1.4	1.9	1.9	1.5	1.0	0.7	0.6	1.1	2.1	3.6	5.4	8.8	13.7	21.3	31.9	45.5	62.6
NPV (9.54% discount rate)	49.1																			
Energy Services Charge (M$)	1.0	4.2	9.2	16.6	27.0	41.1	66.7	96.0	126.8	158.9	191.7	226.2	262.4	300.6	335.0	365.0	371.8	376.6	378.8	378.7
NPV (9.54% discount rate)	1124.1																			
Total Resource Cost (M$)																				
Nominal	1910.7	2005.7	2223.2	2358.9	2483.9	2716.5	2978.8	3290.5	3707.1	4140.0	4720.1	5223.6	5760.1	6265.2	6924.0	7590.4	8381.2	9157.7	10026.2	11061.2
Real	1910.7	1908.4	2012.7	2031.9	2035.7	2118.3	2210.2	2323.0	2490.0	2645.9	2870.3	3022.3	3171.0	3281.7	3450.8	3599.3	3781.5	3931.3	4095.3	4298.8
NPV (9.54% discount rate)	37240.5																			
Average Growth																				
Nominal	9.68%																			
Real	4.36%																			
Mills / KWh																				
Nominal	45.9	45.1	48.3	49.3	50.0	52.4	55.5	59.0	63.9	68.4	75.3	80.1	84.9	88.5	94.3	99.4	105.6	110.6	116.8	123.9
Real	45.9	42.9	43.7	42.5	41.0	40.9	41.2	41.7	42.9	43.7	45.8	46.3	46.7	46.4	47.0	47.2	47.6	47.5	47.7	48.1
Average Growth																				
Nominal	5.37%																			
Real	0.25%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Actual

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,535	5,750	5,974	6,207	6,450	6,701	6,962	7,241	7,532	7,832	8,146	8,472	8,812	9,164	9,531	9,912	10,310	10,722	11,151	11,597
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,629	6,745	6,975	7,212	7,478	7,737	8,000	8,227	8,503	8,779	9,092	9,395	9,638	9,918	10,253	10,548	10,945	11,313	11,734	12,180
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	4	8	14	24	37	50	63	77	90	104	117	130	143	155	166	177	188	200	211	223
D.S. Options (1)	12	23	40	64	103	154	212	272	329	382	432	479	526	569	601	619	637	654	670	685
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen (2)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (3)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (4)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Large CT (1)					31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Wyodak 2 (1)										192	192	192	192	192	192	192	192	192	192	192
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (3)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Hunter 4 (1)											300	300	300	300	300	300	300	300	300	300
Large CT (4)								31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CT (1)								20	20	20	20	20	20	20	20	20	20	20	20	20
Large CT (5)								31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (1)									16	31	31	31	31	31	31	31	31	31	31	31
Medium CT (2)									20	20	20	20	20	20	20	20	20	20	20	20
Medium CT (3)									20	20	20	20	20	20	20	20	20	20	20	20
Large CC CT (2)										175	175	175	175	175	175	175	175	175	175	175
Large CT (6)										31	31	31	31	31	31	31	31	31	31	31
Large CC CT (3)												175	175	175	175	175	175	175	175	175
Small CT (1)												8	8	8	8	8	8	8	8	8
Small CT (Jul) (1)												4	8	8	8	8	8	8	8	8
Small CT (Jul) (2)												4	8	8	8	8	8	8	8	8
Small CT (Jul) (3)												4	8	8	8	8	8	8	8	8
Large CC CT													175	175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT														175	175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT																175	175	175	175	175
Large CC CT																175	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT																		175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Large CC CT																			175	175
Large CC CT (Jul)																			88	175
Large CC CT																				175
Large CC CT																				175
Small CT																				8
total	6,699	6,788	7,029	7,224	7,567	7,776	8,056	8,190	8,451	8,947	9,362	9,545	9,843	10,181	10,410	10,752	11,168	11,484	11,929	12,334
Balance	71	43	55	12	89	39	56	-37	-52	168	269	150	204	263	157	205	223	171	196	154

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Actual

4/2/92 8:38

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,206	7,487	7,779	8,082	8,397	8,725	9,065	9,428	9,806	10,198	10,606	11,031	11,473	11,932	12,409	12,906	13,423	13,960	14,519	15,100
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	601	601	601	601	526	526
total	8,483	8,740	9,032	9,339	9,556	9,884	10,224	10,587	10,915	11,307	11,715	12,140	12,382	12,741	13,210	13,507	14,024	14,561	15,045	15,626
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	5	11	20	34	52	70	90	110	130	150	170	190	209	228	246	264	283	301	320	339
D.S. Options (1)	14	29	52	88	153	242	343	447	546	636	718	797	875	946	998	1,029	1,059	1,087	1,114	1,139
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (3)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (4)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)											400	400	400	400	400	400	400	400	400	400
Large CT (4)								156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (5)								156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)										156	156	156	156	156	156	156	156	156	156	156
Medium CT (2)									100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (3)									100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CT (6)										156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)												250	250	250	250	250	250	250	250	250
Small CT (1)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)													40	40	40	40	40	40	40	40
Small CT (Jul) (2)													40	40	40	40	40	40	40	40
Small CT (Jul) (3)													40	40	40	40	40	40	40	40
Large CC CT													250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																			250	250
Large CC CT (Jul)																				250
Large CC CT																				250
Large CC CT																				250
Small CT																				40
total	9,482	9,870	10,178	10,594	11,143	11,399	12,263	12,859	13,215	14,201	14,728	15,114	15,545	16,140	16,332	16,898	17,403	17,950	18,330	19,182
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,412	1,452	1,526	1,596	1,636	1,768	1,831	1,874	1,930	2,005	2,042	2,117	2,192	2,267	2,342	2,461
Balance	-301	-170	-154	-73	175	63	512	676	665	1,126	1,182	1,100	1,234	1,395	1,080	1,274	1,187	1,122	943	1,096
(Reserve+Balance)/Requirement	12%	13%	13%	13%	17%	15%	20%	21%	21%	26%	26%	25%	26%	27%	24%	25%	24%	23%	22%	23%

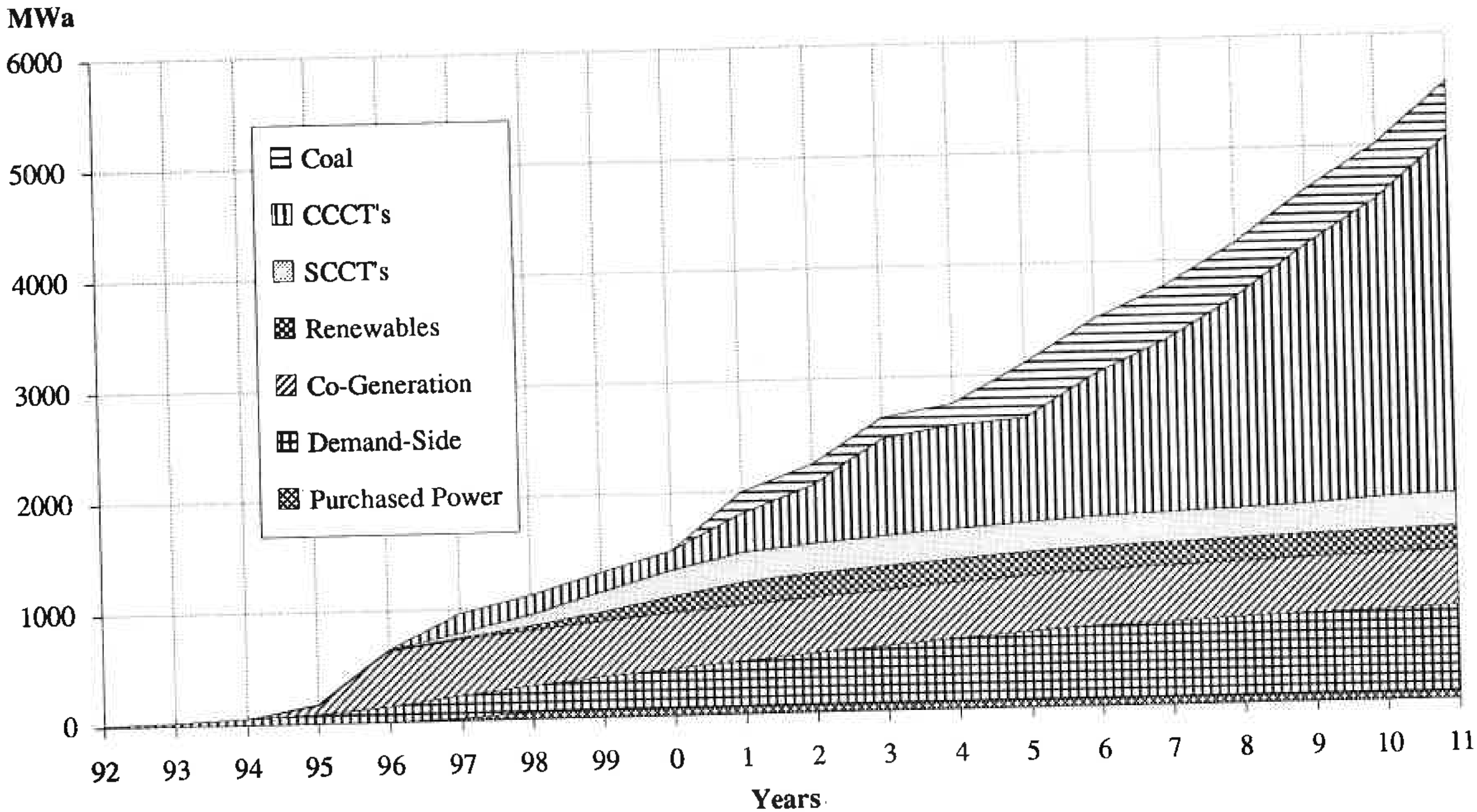
PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Actual

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,738	7,000	7,273	7,557	7,852	8,158	8,476	8,816	9,169	9,536	9,917	10,314	10,727	11,157	11,603	12,068	12,551	13,053	13,576	14,119
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,551	8,613	8,890	9,176	9,566	9,837	10,155	10,355	10,723	10,995	11,376	11,773	11,986	12,308	12,754	13,019	13,502	13,929	14,452	14,995
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	8	14	24	37	49	62	76	89	102	116	129	141	154	166	178	190	202	215	227
D.S. Options (1)	11	23	41	69	124	197	281	367	449	527	601	673	744	808	857	884	911	937	961	985
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (3)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (4)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (1)					156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Hunter 4 (1)											400	400	400	400	400	400	400	400	400	400
Large CT (4)								156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (5)								156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (1)									156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (2)									100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (3)									100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CT (6)										156	156	156	156	156	156	156	156	156	156	156
Large CC CT (3)												250	250	250	250	250	250	250	250	250
Small CT (1)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)												40	40	40	40	40	40	40	40	40
Small CT (Jul) (3)												40	40	40	40	40	40	40	40	40
Large CC CT													250	250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT														250	250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																			250	250
Large CC CT (Jul)																			250	250
Large CC CT																				250
Large CC CT																				250
Small CT																				40
total	9,785	9,837	10,162	10,508	10,961	11,188	11,571	12,109	12,630	13,435	13,940	14,397	14,732	15,314	15,508	16,103	16,648	17,187	17,824	18,402
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,328	1,412	1,452	1,526	1,596	1,636	1,768	1,831	1,874	1,930	2,005	2,042	2,117	2,192	2,267	2,342	2,461
Balance	-66	-76	-29	4	-16	-101	-111	158	272	672	733	749	816	1,001	712	967	954	991	1,030	946
(Reserve+Balance)/Requirement	14%	14%	14%	15%	15%	14%	14%	17%	18%	22%	23%	22%	23%	24%	22%	24%	23%	23%	23%	23%

PacifiCorp - RAMPP 2

Illustrative Plan

Medium-High Forecast, High Excursion



KEY OUTPUTS

Med-High Forecast, High Excursion (92-98)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
System Load (MWa)	5200.0	5534.8	5750.1	5974.4	6207.4	6450.1	6701.0	6962.3	7171.2	7387.1
Total Conservation	4.5	15.5	30.9	54.0	88.0	139.7	203.6	236.8	299.9	361.0
System Load net of Conservation	5195.5	5519.3	5719.2	5920.3	6119.4	6310.4	6497.4	6725.5	6871.2	7026.1
Energy Sales after Conservation	4749.7	5045.8	5228.5	5412.3	5594.3	5769.0	5939.9	6148.5	6281.7	6423.3
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485
Net Electric Plant (M$)	5945.7	6506.6	6811.4	7120.0	7514.9	8139.3	9148.6	10348.7	11533.9	12644.7
Net Conservation Assets	16.1	57.5	119.6	208.6	335.3	504.7	794.1	1117.2	1390.4	1645.8
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)										
Nominal	1910.9	2001.2	2212.2	2338.9	2460.6	2652.6	2905.7	3188.7	3553.3	3910.5
Real	1910.9	1904.1	2002.7	2014.6	2016.7	2068.5	2155.9	2251.1	2386.8	2499.3
NPV (9.54% discount rate)	34745.8									
Average Growth										
Nominal	8.82%									
Real	3.54%									
Base Unit Cost (mills/kwh)										
Nominal	45.9	45.2	48.3	49.3	50.2	52.3	55.8	59.2	64.6	69.3
Real	45.9	43.0	43.7	42.5	41.2	40.8	41.4	41.8	43.4	44.3
Average Growth										
Nominal	5.00%									
Real	-0.09%									
Average Customer Bill ($)										
Nominal	1566.3	1602.9	1744.7	1815.2	1867.4	1962.0	2096.1	2249.1	2446.9	2633.7
Real	1566.3	1525.1	1579.4	1563.6	1530.4	1530.0	1555.3	1587.8	1643.6	1683.2
NPV (9.54% discount rate)	23488.2									
Customer Cost (M$)	2.8	3.6	3.6	3.9	5.0	0.0	-3.9	-4.8	-4.2	-2.3
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.3	0.7	1.0	1.4	1.9	1.9	1.5	1.0	0.6	0.4
NPV (9.54% discount rate)	44.2									
Energy Services Charge (M$)	1.0	4.2	9.2	16.6	27.0	41.1	66.7	96.0	110.4	138.1
NPV (9.54% discount rate)	995.1									
Total Resource Cost (M$)										
Nominal	1912.2	2006.0	2222.5	2356.9	2489.6	2695.7	2973.9	3285.8	3664.4	4049.0
Real	1912.2	1908.7	2012.0	2030.2	2040.4	2102.1	2206.5	2319.6	2461.4	2587.7
NPV (9.54% discount rate)	35785.1									
Average Growth										
Nominal	9.04%									
Real	3.75%									
Mills / KWh										
Nominal	45.9	45.1	48.3	49.3	50.1	52.0	55.4	58.9	63.8	68.3
Real	45.9	42.9	43.7	42.4	41.0	40.6	41.1	41.6	42.9	43.6
Average Growth										
Nominal	4.82%									
Real	-0.26%									

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	7687.4	8001.0	8327.1	8667.6	9018.9	9385.8	9767.3	10165.5	10576.7	11005.8
Total Conservation	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	7269.4	7529.0	7803.0	8092.4	8396.6	8726.6	9082.6	9455.4	9842.3	10247.8
Energy Sales after Conservation	6645.7	6883.0	7133.5	7398.1	7676.1	7977.9	8303.3	8644.1	8997.8	9368.5
Total Customers (000's)	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	13667.9	14603.5	15594.4	16716.5	17770.2	18783.6	19819.5	21005.8	21932.0	22310.6
Net Conservation Assets	1872.2	2077.2	2268.4	2447.8	2598.9	2667.3	2650.1	2633.9	2609.3	2580.4
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)										
Nominal	4381.5	4748.9	5193.4	5599.1	6144.7	6720.3	7386.2	8032.0	8724.0	9527.0
Real	2664.4	2747.6	2859.1	2932.8	3062.4	3186.7	3332.6	3448.1	3563.4	3702.6
Base Unit Cost (mills/kwh)										
Nominal	75.3	78.8	83.1	86.2	91.4	96.2	101.5	105.8	110.7	116.1
Real	45.8	45.6	45.8	45.1	45.5	45.6	45.8	45.4	45.2	45.1
Average Customer Bill ($)										
Nominal	2887.1	3056.7	3267.8	3449.9	3713.0	3988.5	4306.6	4595.7	4891.0	5234.3
Real	1755.6	1768.6	1798.9	1807.0	1850.5	1891.3	1943.1	1972.9	1997.8	2034.3
Customer Cost (M$)	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$) *(30 years at a 9.54% discount rate)*	0.7	1.5	2.8	4.4	7.7	12.2	19.5	28.8	41.0	56.3
Energy Services Charge (M$)	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
Total Resource Cost (M$)										
Nominal	4548.3	4946.1	5423.0	5863.0	6444.2	7050.0	7727.9	8387.1	9092.0	9908.0
Real	2765.8	2861.8	2985.4	3071.0	3211.7	3343.1	3486.7	3600.5	3713.7	3850.6
Mills / KWh										
Nominal	73.9	77.2	81.3	84.2	89.2	93.8	98.8	102.7	107.3	112.4
Real	44.9	44.7	44.8	44.1	44.5	44.5	44.6	44.1	43.8	43.7

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Excursion

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,535	5,750	5,974	6,207	6,450	6,701	6,962	7,171	7,387	7,687	8,001	8,327	8,668	9,019	9,386	9,767	10,166	10,577	11,006	11,452
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,629	6,745	6,975	7,212	7,478	7,737	8,000	8,157	8,358	8,634	8,947	9,250	9,494	9,773	10,108	10,403	10,801	11,168	11,589	12,035
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	4	8	14	24	37	50	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	12	23	40	64	103	154	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Small CT (1)				8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (3)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (4)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)						31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Wyodak 2 (1)										192	192	192	192	192	192	192	192	192	192	192
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (3)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Small CT (2)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (3)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (1)								4	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)								4	8	8	8	8	8	8	8	8	8	8	8	8
Large CT (4)								31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CT (1)								20	20	20	20	20	20	20	20	20	20	20	20	20
Large CT (Jul) (1)									16	31	31	31	31	31	31	31	31	31	31	31
Large CT (Jul) (2)									16	31	31	31	31	31	31	31	31	31	31	31
Medium CT (2)									20	20	20	20	20	20	20	20	20	20	20	20
Large CC CT (2)										175	175	175	175	175	175	175	175	175	175	175
Large CC CT (3)											175	175	175	175	175	175	175	175	175	175
Hunter 4 (1)														300	300	300	300	300	300	300
Large CC CT (4)												175	175	175	175	175	175	175	175	175
Large CC CT (5)												175	175	175	175	175	175	175	175	175
Medium CC CT													64	64	64	64	64	64	64	64
Large CC CT															175	175	175	175	175	175
Large CC CT															175	175	175	175	175	175
Large CC CT																175	175	175	175	175
Large CC CT (Jul)																88	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT (Jul)																	88	175	175	175
Large CC CT																		175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Large CC CT																			175	175
Large CT																			31	31
Large CC CT																				175
Large CC CT																				175
Large CC CT																				175
total	6,699	6,788	7,029	7,152	7,544	7,784	8,026	8,142	8,396	8,867	9,148	9,479	9,644	9,926	10,324	10,575	10,985	11,386	11,770	12,251
Balance	71	43	55	-60	66	47	25	-15	38	234	201	229	150	153	216	172	185	218	181	216

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Excursion

4/24/92 13:37

Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Requirements										
System Loads	7,206	7,487	7,779	8,082	8,397	8,725	9,065	9,337	9,617	10,010
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109
total	8,483	8,740	9,032	9,339	9,556	9,884	10,224	10,496	10,726	11,119
Resources										
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518
D.S. Lost Opportunities (1)	5	11	20	34	52	70	78	95	113	130
D.S. Options (1)	14	29	52	88	153	242	294	383	468	545
BPA Entitlement (1)							164	164	164	164
Geothermal-Pilot (1)								50	100	150
Wind-Pilot (1)						16	39	39	55	71
CoGen (1)				94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40
CoGen 1 (1)					100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100
CoGen 1 (3)					100	100	100	100	100	100
CoGen 1 (4)					100	100	100	100	100	100
CoGen (2)					94	94	94	94	94	94
Large CC CT (1)						250	250	250	250	250
Large CT (1)						156	156	156	156	156
Wyodak 2 (1)										256
Large CT (2)							156	156	156	156
Large CT (3)							156	156	156	156
Small CT (2)								40	40	40
Small CT (3)								40	40	40
Small CT (Jul) (1)									40	40
Small CT (Jul) (2)									40	40
Large CT (4)								156	156	156
Medium CT (1)								100	100	100
Large CT (Jul) (1)										156
Large CT (Jul) (2)										156
Medium CT (2)									100	100
Large CC CT (2)										250
Large CC CT (3)										
Hunter 4 (1)										
Large CC CT (4)										
Large CC CT (5)										
Medium CC CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT (Jul)										
Large CC CT										
Large CC CT (Jul)										
Large CC CT										
Large CC CT										
Large CC CT										
Large CC CT										
Large CT										
Large CC CT										
Large CC CT										
Large CC CT										
total	9,482	9,870	10,178	10,540	11,027	11,439	12,242	12,745	13,065	14,035
Reserve Requirement										
Total Company Reserve	1,300	1,300	1,300	1,320	1,394	1,458	1,532	1,590	1,627	1,760
Balance	-301	-170	-154	-119	76	97	485	659	711	1,156
(Reserve+Balance)/Requirement	12%	13%	13%	13%	15%	16%	20%	21%	22%	26%

Winter Peak	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements										
System Loads	10,418	10,843	11,284	11,743	12,221	12,718	13,234	13,772	14,330	14,911
Firm Sales	1,109	1,109	909	809	801	601	601	601	526	526
total	11,527	11,952	12,193	12,552	13,022	13,319	13,835	14,373	14,856	15,437
Resources										
Existing Generation	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)	87	87	87	87	87	87	87	87	87	87
CoGen (1)	94	94	94	94	94	94	94	94	94	94
Small CT (1)	40	40	40	40	40	40	40	40	40	40
CoGen 1 (1)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (3)	100	100	100	100	100	100	100	100	100	100
CoGen 1 (4)	100	100	100	100	100	100	100	100	100	100
CoGen (2)	94	94	94	94	94	94	94	94	94	94
Large CC CT (1)	250	250	250	250	250	250	250	250	250	250
Large CT (1)	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)	256	256	256	256	256	256	256	256	256	256
Large CT (2)	156	156	156	156	156	156	156	156	156	156
Large CT (3)	156	156	156	156	156	156	156	156	156	156
Small CT (2)	40	40	40	40	40	40	40	40	40	40
Small CT (3)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)	40	40	40	40	40	40	40	40	40	40
Large CT (4)	156	156	156	156	156	156	156	156	156	156
Medium CT (1)	100	100	100	100	100	100	100	100	100	100
Large CT (Jul) (1)	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (2)	156	156	156	156	156	156	156	156	156	156
Medium CT (2)	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)	250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)				400	400	400	400	400	400	400
Large CC CT (4)		250	250	250	250	250	250	250	250	250
Large CC CT (5)		250	250	250	250	250	250	250	250	250
Medium CC CT			128	128	128	128	128	128	128	128
Large CC CT					250	250	250	250	250	250
Large CC CT					250	250	250	250	250	250
Large CC CT						250	250	250	250	250
Large CC CT (Jul)							250	250	250	250
Large CC CT							250	250	250	250
Large CC CT (Jul)								250	250	250
Large CC CT								250	250	250
Large CC CT								250	250	250
Large CC CT									250	250
Large CC CT									250	250
Large CT									156	156
Large CC CT										250
Large CC CT										250
Large CC CT										250
total	14,397	14,980	15,155	15,637	16,069	16,379	16,877	17,668	18,197	19,003
Reserve Requirement										
Total Company Reserve	1,800	1,875	1,894	1,954	2,029	2,066	2,141	2,254	2,352	2,465
Balance	1,071	1,154	1,068	1,131	1,019	994	900	1,041	988	1,101
(Reserve+Balance)/Requirement	25%	25%	24%	25%	23%	23%	22%	23%	22%	23%

L&R - MHe/Hex 4/24

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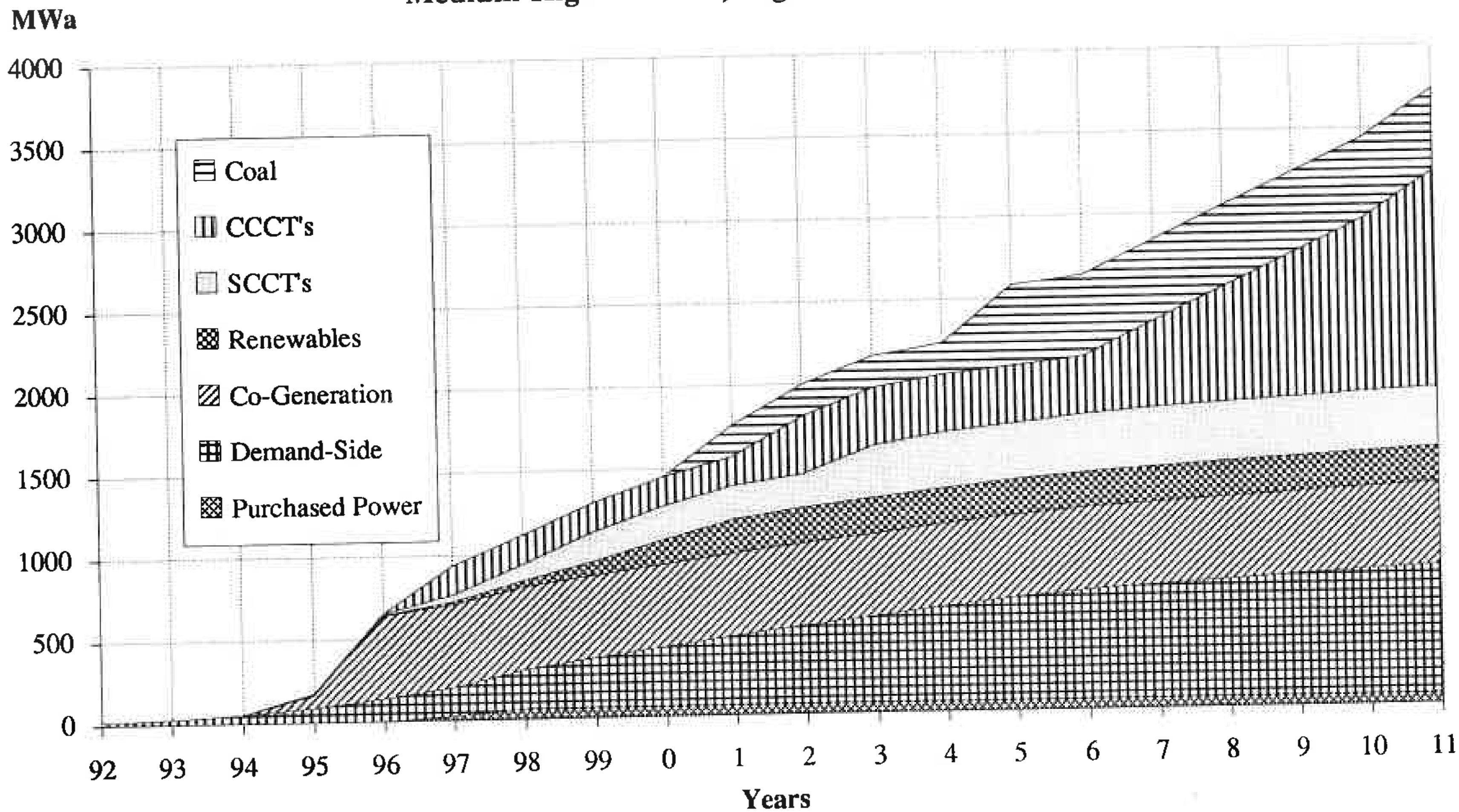
PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Excursion

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,738	7,000	7,273	7,557	7,852	8,158	8,476	8,730	8,992	9,359	9,741	10,138	10,551	10,981	11,427	11,892	12,375	12,877	13,399	13,943
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,551	8,613	8,890	9,176	9,566	9,837	10,155	10,269	10,546	10,818	11,200	11,597	11,810	12,132	12,578	12,843	13,326	13,753	14,275	14,819
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	8	14	24	37	49	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	11	23	41	69	124	197	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)																				
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (3)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (4)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Large CT (4)								156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Large CT (Jul) (1)									156	156	156	156	156	156	156	156	156	156	156	156
Large CT (Jul) (2)									156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (2)									100	100	100	100	100	100	100	100	100	100	100	100
Large CC CT (2)										250	250	250	250	250	250	250	250	250	250	250
Large CC CT (3)											250	250	250	250	250	250	250	250	250	250
Hunter 4 (1)														400	400	400	400	400	400	400
Large CC CT (4)												250	250	250	250	250	250	250	250	250
Large CC CT (5)												250	250	250	250	250	250	250	250	250
Medium CC CT													128	128	128	128	128	128	128	128
Large CC CT															250	250	250	250	250	250
Large CC CT															250	250	250	250	250	250
Large CC CT																250	250	250	250	250
Large CC CT (Jul)																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT (Jul)																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																			250	250
Large CT																			156	156
Large CC CT																				250
Large CC CT																				250
Large CC CT																				250
total	9,785	9,837	10,162	10,454	10,845	11,228	11,563	12,091	12,654	13,291	13,633	14,168	14,369	14,840	15,276	15,866	16,405	16,939	17,477	18,260
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,394	1,458	1,532	1,590	1,627	1,760	1,800	1,875	1,894	1,954	2,029	2,066	2,141	2,254	2,352	2,465
Balance	-66	-76	-29	-42	-115	-67	-125	231	480	712	633	696	665	755	669	957	938	932	849	976
(Reserve+Balance)/Requirement	14%	14%	14%	14%	13%	14%	14%	18%	20%	23%	22%	22%	22%	22%	21%	24%	23%	23%	22%	23%

PacifiCorp - RAMPP 2

Illustrative Plan

Medium-High Forecast, High Short Excursion Actuals



KEY OUTPUTS

Med-High Forecast, High Short Excursion

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System Load (MWa)	5200.0	5534.8	5750.1	5974.4	6207.4	6394.2	6580.8	6771.8	7002.8	7232.2	7464.8	7694.8	7925.8	8145.2	8360.8	8598.8	8818.8	9028.2	9234.8	9447.8
Total Conservation	4.5	15.5	30.9	54.0	88.0	139.7	173.9	236.8	299.9	361.0	418.0	472.0	524.1	575.2	622.4	659.2	684.6	710.1	734.4	758.0
System Load net of Conservation	5195.5	5519.3	5719.2	5920.3	6119.4	6254.6	6406.9	6535.0	6702.9	6871.3	7046.8	7222.8	7401.7	7570.1	7738.5	7939.7	8134.2	8318.1	8500.4	8689.8
Energy Sales after Conservation	4749.7	5045.8	5228.5	5412.3	5594.3	5717.9	5857.2	5974.3	6127.8	6281.7	6442.2	6603.1	6766.7	6920.6	7074.5	7258.4	7436.3	7604.4	7771.1	7944.2
Total Customers (000's)	1,220	1,249	1,268	1,289	1,318	1,352	1,386	1,418	1,452	1,485	1,518	1,554	1,589	1,623	1,655	1,685	1,715	1,748	1,784	1,820
Net Electric Plant (M$)	5945.7	6506.6	6811.4	7120.0	7514.9	8122.0	9035.9	9983.6	10905.1	11789.0	12768.8	13690.4	14439.8	15208.3	15866.3	16500.1	17123.3	17847.5	18476.7	18848.5
Net Conservation Assets	16.1	57.5	119.6	208.6	335.3	487.4	729.0	1008.3	1289.2	1552.2	1786.2	1998.8	2197.7	2384.7	2543.5	2619.5	2609.9	2601.3	2584.3	2563.1
General Inflation Rate	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%	5.10%
Operating Revenues (M$)																				
Nominal	1910.9	2001.2	2212.2	2338.9	2460.6	2640.3	2871.1	3104.4	3433.3	3723.0	4132.3	4477.9	4911.5	5272.6	5770.7	6247.1	6799.0	7326.9	7885.6	8524.0
Real	1910.9	1904.1	2002.7	2014.6	2016.7	2059.0	2130.3	2191.6	2306.2	2379.4	2512.8	2590.9	2703.8	2761.8	2876.0	2962.4	3067.6	3145.4	3221.0	3312.8
NPV (9.54% discount rate)	33287.3																			
Average Growth																				
Nominal	8.19%																			
Real	2.94%																			
Base Unit Cost (mills/kwh)																				
Nominal	45.9	45.2	48.3	49.3	50.2	52.6	56.0	59.3	64.0	67.5	73.2	77.4	82.9	86.7	93.1	98.3	104.4	109.7	115.8	122.5
Real	45.9	43.0	43.7	42.5	41.2	41.0	41.5	41.9	43.0	43.1	44.5	44.8	45.6	45.4	46.4	46.6	47.1	47.1	47.3	47.6
Average Growth																				
Nominal	5.30%																			
Real	0.19%																			
Average Customer Bill ($)																				
Nominal	1566.3	1602.9	1744.7	1815.2	1867.4	1952.9	2071.2	2189.6	2364.2	2507.4	2722.9	2882.3	3090.3	3248.7	3487.1	3707.7	3964.2	4192.3	4420.9	4683.3
Real	1566.3	1525.1	1579.4	1563.6	1530.4	1522.9	1536.8	1545.8	1588.1	1602.5	1655.8	1667.7	1701.3	1701.7	1737.9	1758.2	1788.6	1799.7	1805.8	1820.1
NPV (9.54% discount rate)	22601.3																			
Customer Cost (M$)	2.8	3.6	3.6	3.9	5.0	-1.1	-5.3	-5.9	-4.2	-2.3	2.8	8.0	12.9	16.0	31.7	44.8	71.1	90.9	120.4	149.9
Levelized Customer Cost (M$)																				
(30 years at a 9.54% discount rate)	0.3	0.7	1.0	1.4	1.9	1.8	1.3	0.7	0.2	0.0	0.3	1.1	2.4	4.1	7.3	11.9	19.1	28.4	40.7	56.0
NPV (9.54% discount rate)	42.5																			
Energy Services Charge (M$)	1.0	4.2	9.2	16.6	27.0	37.1	58.5	83.8	110.4	138.1	166.2	195.8	226.8	259.4	291.8	317.5	322.2	326.3	326.9	324.6
NPV (9.54% discount rate)	981.4																			
Total Resource Cost (M$)																				
Nominal	1912.2	2006.0	2222.5	2356.9	2489.6	2679.3	2930.9	3188.9	3544.0	3861.1	4298.8	4674.9	5140.7	5536.1	6069.8	6576.5	7140.3	7681.7	8253.2	8904.6
Real	1912.2	1908.7	2012.0	2030.2	2040.4	2089.3	2174.6	2251.2	2380.5	2467.7	2614.1	2704.8	2830.0	2899.8	3025.1	3118.6	3221.6	3297.7	3371.1	3460.7
NPV (9.54% discount rate)	34311.2																			
Average Growth																				
Nominal	8.43%																			
Real	3.17%																			
Mills / KWh																				
Nominal	45.9	45.1	48.3	49.3	50.1	52.2	55.6	58.8	63.2	66.5	71.9	75.9	81.0	84.6	90.7	95.5	101.1	106.0	111.6	117.7
Real	45.9	42.9	43.7	42.4	41.0	40.7	41.3	41.5	42.4	42.5	43.7	43.9	44.6	44.3	45.2	45.3	45.6	45.5	45.6	45.7
Average Growth																				
Nominal	5.08%																			
Real	-0.02%																			

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Short Excursion

Average Megawatts	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	5,535	5,750	5,974	6,207	6,394	6,581	6,772	7,003	7,232	7,465	7,695	7,926	8,145	8,361	8,599	8,819	9,028	9,235	9,448	9,668
Firm Sales	1,094	995	1,000	1,004	1,028	1,036	1,038	985	971	946	946	923	826	754	722	635	635	591	583	583
total	6,629	6,745	6,975	7,212	7,422	7,617	7,810	7,988	8,203	8,411	8,641	8,849	8,971	9,115	9,321	9,454	9,663	9,826	10,031	10,251
Resources																				
Existing Generation	6,072	6,126	6,301	6,294	6,337	6,283	6,344	6,280	6,355	6,316	6,357	6,296	6,351	6,282	6,355	6,316	6,357	6,296	6,350	6,282
Firm Purchases	612	632	675	682	554	535	566	558	556	551	553	542	538	540	479	480	474	474	400	401
D.S. Lost Opportunities (1)	4	8	14	24	37	44	55	67	78	90	101	113	124	134	144	154	163	173	183	193
D.S. Options (1)	12	23	40	64	103	130	182	233	283	328	371	411	451	488	515	531	547	561	575	588
BPA Entitlement (1)						26	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Geothermal-Pilot (1)								45	90	135	135	135	135	135	135	135	135	135	135	135
Wind-Pilot (1)					5	22	38	42	58	73	83	83	83	83	83	83	83	83	83	83
CoGen (1)				80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Small CT (1)				8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CoGen 1 (1)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (2)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (3)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen 1 (4)					85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
CoGen (2)					80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Large CC CT (1)						175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
Large CT (1)						31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Wyodak 2 (1)										192	192	192	192	192	192	192	192	192	192	192
Large CT (2)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Large CT (3)							31	31	31	31	31	31	31	31	31	31	31	31	31	31
Small CT (2)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (3)								8	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (1)								4	8	8	8	8	8	8	8	8	8	8	8	8
Small CT (Jul) (2)								4	8	8	8	8	8	8	8	8	8	8	8	8
Large CT (4)								31	31	31	31	31	31	31	31	31	31	31	31	31
Medium CT (1)								20	20	20	20	20	20	20	20	20	20	20	20	20
Medium CT (2)									20	20	20	20	20	20	20	20	20	20	20	20
Hunter 4 (1)														300	300	300	300	300	300	300
Large CC CT (2)											175	175	175	175	175	175	175	175	175	175
Large CT (5)												31	31	31	31	31	31	31	31	31
Large CT (6)												31	31	31	31	31	31	31	31	31
Large CT (7)												31	31	31	31	31	31	31	31	31
Medium CT (3)												20	20	20	20	20	20	20	20	20
Medium CT													20	20	20	20	20	20	20	20
Small CT (Jul)															4	8	8	8	8	8
Small CT (Jul)															4	8	8	8	8	8
Small CT															8	8	8	8	8	8
Large CC CT																175	175	175	175	175
Large CC CT																	175	175	175	175
Large CC CT																		175	175	175
Large CC CT																			175	175
Large CC CT																				175
Large CC CT (Jul)																				88
total	6,699	6,788	7,029	7,152	7,544	7,754	8,026	8,142	8,365	8,630	8,911	9,005	9,127	9,408	9,472	9,643	9,879	10,017	10,195	10,415
Balance	71	43	55	-60	122	138	216	153	161	219	270	156	156	293	151	189	216	190	164	164

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PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Short Excursion

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Winter Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	7,206	7,487	7,779	8,082	8,325	8,574	8,827	9,136	9,440	9,748	10,054	10,362	10,654	10,941	11,255	11,546	11,824	12,098	12,382	12,674
Firm Sales	1,277	1,253	1,253	1,257	1,159	1,159	1,159	1,159	1,109	1,109	1,109	1,109	909	809	801	601	601	601	526	526
total	8,483	8,740	9,032	9,339	9,484	9,733	9,986	10,295	10,549	10,857	11,163	11,471	11,563	11,750	12,056	12,147	12,425	12,699	12,908	13,200
Resources																				
Existing Generation	7,234	7,508	7,683	7,746	7,750	7,754	7,766	7,771	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776	7,776
Firm Purchases	2,229	2,323	2,422	2,538	2,443	2,323	2,554	2,559	2,526	2,518	2,526	2,524	2,488	2,493	2,364	2,382	2,338	2,339	2,173	2,191
D.S. Lost Opportunities (1)	5	11	20	34	52	62	78	95	113	130	148	165	181	198	214	229	245	261	278	294
D.S. Options (1)	14	29	52	88	153	204	294	383	468	545	616	684	751	812	856	883	909	933	955	977
BPA Entitlement (1)							164	164	164	164	164	164	164	164	164	164	164	164	164	164
Geothermal-Pilot (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Wind-Pilot (1)						16	39	39	55	71	87	87	87	87	87	87	87	87	87	87
CoGen (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Small CT (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (3)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (4)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen (2)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Large CC CT (1)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Wyodak 2 (1)										256	256	256	256	256	256	256	256	256	256	256
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Small CT (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)									40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)									40	40	40	40	40	40	40	40	40	40	40	40
Large CT (4)								156	156	156	156	156	156	156	156	156	156	156	156	156
Medium CT (1)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (2)									100	100	100	100	100	100	100	100	100	100	100	100
Hunter 4 (1)														400	400	400	400	400	400	400
Large CC CT (2)											250	250	250	250	250	250	250	250	250	250
Large CT (5)												156	156	156	156	156	156	156	156	156
Large CT (6)												156	156	156	156	156	156	156	156	156
Large CT (7)												156	156	156	156	156	156	156	156	156
Medium CT (3)												100	100	100	100	100	100	100	100	100
Medium CT													100	100	100	100	100	100	100	100
Small CT (Jul)																40	40	40	40	40
Small CT (Jul)																40	40	40	40	40
Small CT															40	40	40	40	40	40
Large CC CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT (Jul)																				
total	9,482	9,870	10,178	10,540	11,027	11,393	12,242	12,745	13,065	13,473	13,835	14,486	14,633	15,115	15,087	15,477	15,725	16,016	16,139	16,445
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,394	1,458	1,532	1,590	1,627	1,675	1,715	1,801	1,816	1,876	1,882	1,931	1,969	2,006	2,044	2,081
Balance	-301	-170	-154	-119	149	203	724	860	889	941	957	1,215	1,255	1,490	1,150	1,399	1,332	1,311	1,188	1,165
(Reserve+Balance)/Requirement	12%	13%	13%	13%	16%	17%	23%	24%	24%	24%	24%	26%	27%	29%	25%	27%	27%	26%	25%	25%

PacifiCorp Electric Operations
4/1 RIM - Medium High Forecast
Medium High Forecast/High Short Excursion

Summer Peak	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Requirements																				
System Loads	6,738	7,000	7,273	7,557	7,784	8,024	8,268	8,591	8,887	9,187	9,483	9,779	10,063	10,339	10,648	10,932	11,203	11,468	11,709	11,992
Firm Sales	1,813	1,613	1,617	1,619	1,714	1,679	1,679	1,539	1,554	1,459	1,459	1,459	1,259	1,151	1,151	951	951	876	876	876
total	8,551	8,613	8,890	9,176	9,498	9,703	9,947	10,130	10,441	10,646	10,942	11,238	11,322	11,490	11,799	11,883	12,154	12,344	12,585	12,868
Resources																				
Existing Generation	7,481	7,526	7,719	7,724	7,728	7,740	7,740	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,745
Firm Purchases	2,289	2,281	2,387	2,503	2,329	2,198	2,156	2,129	2,138	2,130	2,137	2,100	2,101	2,106	1,990	2,045	2,051	2,052	1,902	1,904
D.S. Lost Opportunities (1)	3	8	14	24	37	43	54	66	77	89	100	112	123	133	144	155	165	176	186	197
D.S. Options (1)	11	23	41	69	124	167	241	314	385	452	515	577	638	693	735	758	782	804	825	845
BPA Entitlement (1)								50	100	150	150	150	150	150	150	150	150	150	150	150
Geothermal-Pilot (1)						10	25	25	35	45	55	55	55	55	55	55	55	55	55	55
Wind-Pilot (1)				94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (1)				40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (1)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (2)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (3)					100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CoGen 1 (4)					94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CoGen (2)						250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Large CC CT (1)						156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (1)										256	256	256	256	256	256	256	256	256	256	256
Wyodak 2 (1)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (2)							156	156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (2)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (3)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (1)								40	40	40	40	40	40	40	40	40	40	40	40	40
Small CT (Jul) (2)								156	156	156	156	156	156	156	156	156	156	156	156	156
Large CT (4)								100	100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (1)									100	100	100	100	100	100	100	100	100	100	100	100
Medium CT (2)														400	400	400	400	400	400	400
Hunter 4 (1)											250	250	250	250	250	250	250	250	250	250
Large CC CT (2)												156	156	156	156	156	156	156	156	156
Large CT (5)												156	156	156	156	156	156	156	156	156
Large CT (6)												156	156	156	156	156	156	156	156	156
Large CT (7)												100	100	100	100	100	100	100	100	100
Medium CT (3)													100	100	100	100	100	100	100	100
Medium CT															40	40	40	40	40	40
Small CT (Jul)															40	40	40	40	40	40
Small CT (Jul)															40	40	40	40	40	40
Small CT																250	250	250	250	250
Large CC CT																	250	250	250	250
Large CC CT																		250	250	250
Large CC CT																			250	250
Large CC CT																				250
Large CC CT																				250
Large CC CT (Jul)																				
total	9,785	9,837	10,162	10,454	10,845	11,192	11,563	12,091	12,342	12,729	13,071	13,674	13,847	14,318	14,374	14,714	15,003	15,287	15,419	15,952
Reserve Requirement																				
Total Company Reserve	1,300	1,300	1,300	1,320	1,394	1,458	1,532	1,590	1,627	1,675	1,715	1,801	1,816	1,876	1,882	1,931	1,969	2,006	2,044	2,081
Balance	-66	-76	-29	-42	-47	31	84	370	274	407	414	636	710	953	694	900	881	937	790	1,003
(Reserve+Balance)/Requirement	14%	14%	14%	14%	14%	15%	16%	19%	18%	20%	19%	22%	22%	25%	22%	24%	23%	24%	23%	24%

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