FLEXIBLE CHOICES FOR A CHANGING MARKET

Resource and Market Planning Program

RAMPP - 4

EXECUTIVE SUMMARY

NOVEMBER, 1995

PACIFICORP

Resource and Market Planning Program
RAMPP - 4

EXECUTIVE SUMMARY

"Never make predictions — especially about the future." — Samuel Goldwyn

TIMING IS EVERYTHING

"Never make predictions — especially about the future." — Samuel Goldwyn

Long-range power planning has been a hallmark of the electric utility industry. In the past, electric utilities would forecast the demand for electricity 20 years in advance to allow enough lead time to build new power plants. Siting, permitting and building a new plant could take 10 years or more.

Today, power planning has changed dramatically. With new technologies, more cost-effective fuel choices and a competitive marketplace, electric utilities can meet additional demand more quickly. While it is still valuable to assess long-term needs, utilities have options other than large new power plants for meeting those needs.

In fact, electric utilities are surrounded by choices for where, when and how to get additional power. They can purchase power from other regulated or non-regulated suppliers; trade power with other suppliers; manage their existing system differently to free up additional resources; or develop smaller-scale generation themselves or in partnership with customers.

The major finding in RAMPP-4 is that PacifiCorp needn't make any new resource decisions during the three year action plan period for RAMPP-4. However, the company will continue to be attuned to immediate opportunities that are too good to miss.

By delaying decisions where possible, the company can maintain flexibility until a choice must be made. Then, when it is time to pursue new resources, the company can decide where and how to acquire them based on the most up-to-date information and market conditions. This careful timing of decisions reduces the company's risk and enhances its competitiveness.

In this fast-changing marketplace, flexibility is all-important. Accordingly, it is the underlying theme throughout this report on PacifiCorp's fourth Resource and Market Planning Program (RAMPP-4). PacifiCorp wants to maintain resource options that have short lead times and low capital costs and can be acquired in amounts that closely match needs.

The RAMPP-4 report differs from RAMPP-3 in two key ways:

1. **RAMPP-4 is not a stand-alone document. It accompanies and provides an update to the RAMPP-3 report. Copies of the RAMPP-3 document are available by calling (503) 464-5620.**

2. **RAMPP-3 looked at 155 possible futures. RAMPP-4 considers only 39, for two reasons: First, RAMPP-4 was prepared on a shorter time schedule than RAMPP-3; and, second, PacifiCorp believes 39 cases are sufficient to reconfirm the lessons learned from RAMPP-3 and, at the same time, provide additional information on recent issues and concerns.**

The RAMPP-4 documents include only the main report and two appendices. The RAMPP-3 report provides background information about PacifiCorp's power system and planning process. Together they provide the most current information on PacifiCorp's plans and options for meeting future energy needs.

PERCEPTIONS OF THE FUTURE: WHERE ARE WE HEADED?

PacifiCorp's planning effort is based on some key assumptions about where the electric utility industry is headed. The company sees the following nine trends prevailing:

Competition

The competition for meeting customers' electric energy service needs has increased dramatically over the past decade and will continue to increase. Competition and federal regulatory changes are making it easier for more suppliers to enter the market. The Federal Energy Regulatory Commission (FERC) is opening transmission access, and PacifiCorp expects retail wheeling will exist in some form throughout its service territory within five years. Even without retail wheeling, customers will have more choices for their electricity supplier, including self-generation, independent power producers, other fuels and electricity brokers and marketers.

Regulation

Over the next five years, state regulation of electric utilities will continue to change to reflect a more competitive environment. Several of the states served by PacifiCorp (including California, Montana and Utah) are conducting proceedings on regulatory change and the restructuring of the electric utility industry. PacifiCorp is exploring alternative forms of regulation that will complement rather than impede the workings of the competitive marketplace. The alternatives are aimed at ensuring the availability of power to core customers at fair and reasonable prices, while still providing an incentive for the company to pursue efficiencies and innovations that reduce costs and increase earnings.

Transmission

PacifiCorp believes that full open access to the nation's transmission system will be in place within a few years. FERC has issued a Mega NOPR (Notice of Proposed Rulemaking) that would systematically open the national transmission grid. The proposed rules could result in such consequences as:

- Accelerated use of the transmission system;
- Disaggregation of utilities into generation, transmission and distribution companies; and
- Development of a new market for generation-based ancillary services. These services include load following, loss compensation, system protection, scheduling/dispatching and others.

Wholesale market as a resource

Because of changes occurring in transmission and in power generation, PacifiCorp expects to be able to increasingly rely on the wholesale market for its power needs. Power purchases give the company more flexibility in the way it can meet the energy needs of its customers.

Wholesale market revenues

PacifiCorp's wholesale market activity is growing rapidly. It is expected to increasingly evolve as a separate business with its own strategies, rewards and risks.

Risk

All of the above trends increase risk for both the company's customers and its shareholders. While the company will try to reduce risk, it cannot entirely shield either party from it. The company's main concern is that risks should be balanced with rewards. PacifiCorp is willing to assume risks for its shareholders if they are commensurate with the rewards that can flow to shareholders.

Integrated resource planning

As the electric utility industry becomes more competitive, the need for detailed resource planning under regulatory commission oversight will diminish. The way in which integrated resource planning changes will depend partly on how much of the industry remains regulated. PacifiCorp suggests some ways IRP could evolve in Section VI of this executive summary ("Where Do We Go From Here?").

Timeframe

PacifiCorp believes that as the pace of change quickens in the industry, utilities will have difficulty planning more than five to 10 years ahead because of market uncertainties. Today's assumptions may well be outdated in five to 10 years. Along those lines, the RAMPP-4 analysis uses a 20-year planning horizon with an additional 30 years to account for end effects. However, the discussion in the RAMPP-4 report and the results used to develop the RAMPP-4 action plan focus on only the first 10 years.

Social objectives and the environment

One of the original goals of integrated resource planning was to address certain social and environmental objectives. As the energy marketplace becomes more competitive, it will be increasingly difficult for these objectives to be achieved through energy providers. To be fair, any mechanisms aimed at achieving social and environmental objectives that add to the cost of energy should be applied to all energy providers. Otherwise, it will skew competition in the marketplace. PacifiCorp sees an increased need for the beneficiaries of energy efficiency (demand side management) investments to pay for those measures. It is also pursuing low-cost ways to address environmental concerns.

HOW DOES RAMPP-4 FIT IN?

PacifiCorp's Resource and Market Planning Program gives the company general direction for the future. It is not a blueprint; rather, it provides a framework for decision making. RAMPP allows the company to steer its own course as obstacles and opportunities arise. It provides a tool for evaluating specific resource and marketing opportunities that develop.

Given the two-year cycle for integrated resource planning, and the pace of change in the marketplace, it is impossible for a RAMPP action plan to foretell all of the specific opportunities that might arise before the next planning cycle. Accordingly, the action plan provides general guidance while leaving the company flexibility to respond to changing market conditions.

The RAMPP process also meets regulatory commission requirements for integrated resource planning. The commissions in Idaho, Montana, Oregon, Utah and Washington require the company to:

- **Examine a range of forecasts for its customers' energy needs;**
- **Assess all feasible supply and demand alternatives for meeting those needs in a consistent manner, and assess their external costs;**

- **Strive for a goal of least cost to the utility and its customers, consistent with the long-run public interest.**

- **Develop a long-range plan and a short-term action plan for balancing supply and demand; and**

- **Prepare its plan with substantial public involvement.**

This report summarizes the results from RAMPP-4, the company's fourth cycle through the integrated resource planning process.

Progress on RAMPP-3 action plan

PacifiCorp is on track for achieving all of the items in the RAMPP-3 action plan. In a few cases, the timeframes have been adjusted due to changing market conditions. However, the company is making good progress in achieving its objectives in such areas as demand-side resources; development of two wind projects; involvement in solar energy and photovoltaic demonstration projects; construction of the Hermiston cogeneration project; identification of resources to meet peaking needs; introduction of various energy services, such as time-of-day pricing and alternative levels of service quality; improvements in system efficiency; demonstration of carbon offset projects; and implementation of price design changes that promote efficient use.

Changes for RAMPP-4

The Integrated Planning Model used in RAMPP-3 was modified in two major ways for RAMPP-4. They were:

1. **The addition of a summer peaking requirement.** In RAMPP-3, the model added resources to meet a reserve requirement for only the winter peak. RAMPP-4 considers both winter and summer peaking needs, because, although PacifiCorp's retail load has a higher winter peak, the company also has more winter-peaking resources.

2. **Allowing the model to select the amount of DSM for each case.** In RAMPP-3, the amount of DSM was hard-wired into the model, to force the selection of those resources. RAMPP-4 lets the model choose the amount of DSM for each case, which provides more information on the amount of DSM that is cost-effective under various assumptions.

In addition, the company updated its assumptions and forecasts in RAMPP-4. The principal changes were the following:

- **The new load forecasts for RAMPP-4 tend to be lower than RAMPP-3.**

- **RAMPP-4 analyzed three load forecasts instead of five, as in RAMPP-3.**

- **The reserve margin requirement was lowered from 15 percent to 12 percent.**

- **In RAMPP-4, the Hermiston project is considered part of the existing system; in RAMPP-3 it was only used in one sensitivity.**

- **RAMPP-4 takes into account improvements in the existing system, including turbine upgrades at some of the company's existing coal-fired units that will increase system capacity by about 150 MW.**

- **Non-firm market prices are lower and more consistent across geographical areas.** Non-firm power is power that is bought and sold on the wholesale market on an hourly basis.

- **The updated gas price and escalation rates in RAMPP-4 are lower than the gas price assumptions in RAMPP-3.**

- **RAMPP-4 includes a summer peak purchase option through 2002. RAMPP-3 included no purchases in the portfolio.**

- **RAMPP-4 includes new supply-side and transmission costs.**

THE CASES: 39 VARIATIONS ON THE FUTURE

RAMPP-4 tested 39 possible futures based on varying inputs and assumptions. These included:

The base case (1 case)

This case provided the foundation for most of the other cases. It assumed medium load growth and medium gas price escalation, as did the base cases in RAMPP-3. However, the figure for medium load growth in RAMPP-4 was less than in RAMPP-3 — 2.07 percent rather than 2.13 percent. Medium gas price escalation was also less in RAMPP-4 — 2.11 percent real escalation per year vs. 3.78 percent annual escalation in RAMPP-3. These changes reflected the updated assumptions for RAMPP-4.

Data variations (6 cases)

Six cases tested the impact of changes in data assumptions from RAMPP-3 (various inputs for the IPM code and omission of summer data) and from changes in base system assumptions (leaving out the turbine upgrades, or omitting Hermiston).

Demand-side management (DSM) sensitivities (4 cases)

The model tested one case with no DSM; one with a 20 percent reduction in the cost of all DSM initiatives (based on future possibilities); one with a 15 percent reduction in DSM costs; and one with a 15 percent increase in the cost of DSM initiatives (in case the company is underestimating the cost or overestimating the performance of DSM).

Load growth variations (2 cases)

RAMPP-4 tested two load growth forecasts: a medium-low load forecast, which was 1.06 percent growth per year in winter MW for the 20-year planning horizon; and a medium-high load forecast, which was 2.93 percent growth per year in winter MW for the 20-year horizon. The medium-low forecast could result from a lower level of economic activity in the region, some pricing designs, changes in customers' fuel choices, hookup fees or increased competition. The medium-high forecast could result from a higher level of economic activity in the region, or from increased business through PacifiCorp's competitiveness.

Gas price variations (4 cases)

Four cases tested various levels of gas price escalation along with various levels of non-firm market prices. They assumed:

- **Low gas price escalation (a 0 percent real increase per year) with low non-firm market price escalation (also 0 percent real);**
- **Limited gas (500 MW) at medium escalation (2.11 percent real escalation per year) with additional gas-fired resources at a high escalation rate (3.78 percent real escalation per year), and high non-firm market price escalation;**

- **High gas price escalation (3.78 percent) with high non-firm market price escalation; and**
- **High gas price escalation with medium non-firm market price escalation.**

Wholesale market variations (3 cases)

Three cases considered possible changes in the wholesale market. One forced the model to add new resources in realistic large sizes ("lumps"), rather than in the exact size needed to meet the reserve margin requirement; one lowered non-firm market prices by 25 percent, to consider the effect this would have on total system costs ; and one raised non-firm market prices by 25 percent, to consider the effect on total system costs.

Overbuilding (6 cases)

RAMPP-4 included six cases that might occur if the company were to overbuild; i.e., if it acquired a new resource ahead of retail need (in 1999). Each case considered the effect of overbuilding with various levels of non-firm market prices:

- **Overbuilding 250 MW with lower non-firm market prices (25 percent below the base case);**
- **Overbuilding 250 MW with base case non-firm market prices;**
- **Overbuilding 250 MW with higher non-firm market prices (25 percent higher than the base case);**
- **Overbuilding 500 MW with lower non-firm market prices;**
- **Overbuilding 500 MW with base case non-firm market prices; and**
- **Overbuilding 500 MW with higher non-firm market prices.**

Underbuilding (3 cases)

Three cases considered what might happen if the company underbuilt; e.g., if it decided to rely on the market to meet load growth for the first two years of expected resource need (2003 and 2004). The model tested:

- **Underbuilding with lower non-firm market prices;**
- **Underbuilding with base case non-firm market prices; and**
- **Underbuilding with higher non-firm market prices.**

Transmission variations (3 cases)

One case simulated the effect of essentially "moving" an existing plant from one region to another, which would free up transmission capacity and have the same effect as adding a transmission line. A second case increased the transmission path from Bridger to the Oregon/Washington/California region by 300 MW over the base case, with the financial results including the investment for expanding the path. The third transmission case added 300 MW of transmission capacity from Utah to OWC, and included the investment for that expansion in the financial results.

Renewables (1 cases)

One case artificially lowered the cost of renewables. It assumed the capital costs of new renewable resources at 35 percent of their true value. This was the level of reduction needed to make renewables cost-competitive with gas-fired resources.

Input extensions (3 cases)

RAMPP-4 includes three cases that altered the treatment of inputs in the end-effect years; i.e., the 30 years from 2016 to 2045 that capture financial benefits from the resources added during the later part of the 1996-2015 planning horizon. The cases are:

- **Extension of all existing firm wholesale contracts throughout the planning period.**
- **Extension of load growth and DSM assumptions through the year 2045, rather than stopping at 2015.**
- **Extension of all inputs — including load growth, DSM, gas prices and firm contracts — through the entire 50-year period.**

Environmental adders (3 cases)

RAMPP-3 included 21 cases using environmental adders. RAMPP-4 included three environmental adder cases to test the consistency of results. One assumed low adders, one medium adders, and one high adders. The level of adders depends on the externality costs associated with emissions of NOx, TSP and CO2.

RESULTS: AND THE OUTCOME IS...

Overall findings

The single most significant finding in RAMPP-4 is that PacifiCorp does not need to make any decisions for resource needs in the next three years. Postponing resource decisions is likely to lead to lower-cost opportunities because the cost of acquiring power is declining. However, the company will continue to be alert to immediate opportunities that are too good to miss.

The only resource actions required in the RAMPP-4 three-year action plan are DSM. PacifiCorp will monitor key indicators to determine whether any changes are needed as the action plan period progresses. If any of the following benchmarks is triggered, the company would need to re-examine the RAMPP-4 action plan:

- Load growth for 1995 is below 1.5 percent.
- Load growth for 1995 is above 2.5 percent.
- Accepted gas price forecasts indicate prices will rise by 0 percent real escalation or less (at the level of inflation or less).
- Accepted gas price forecasts indicate prices will rise by 4 percent real escalation or higher.

- Non-firm market prices fall by 25 percent or more from their 1995 levels.
- Non-firm market prices increase by 25 percent or more from their 1995 levels.
- The federal government passes some form of CO2 emissions controls or tax.
- One of the renewable technologies achieves costs that are within 10 percent of the cost of acquiring gas-fired resources at the time a decision would be made.

PacifiCorp believes that wholesale market prices will be soft for five to seven years, with surplus capacity and low incremental prices. This will result from increased transmission access, new utility-owned generating plants coming on-line, independent power production and the development of merchant plants. The increased availability of power in the wholesale market will reduce the need for utilities to build and own plants.

Assuming medium load growth, the model added DSM, summer peak purchases and gas-fired resources in the next 10 years. The model results also supported planned turbine upgrades and the addition of the Hermiston plant. They did not support immediate activities for acquiring renewables, coal-fired resources or transmission upgrades. PacifiCorp is including items in the RAMPP-4 action plan for existing system improvements, renewable resources, clean coal and other opportunities in order to maintain flexibility for the future.

Comparison to RAMPP-3

Compared to RAMPP-3, RAMPP-4:

- **Showed a need for fewer resources due to reduced load forecast, a lower reserve margin, the addition of the Hermiston cogeneration plant, and turbine upgrades;**
- **Confirmed that higher load growth need not cause higher prices;**
- **Added less DSM than the medium level from RAMPP-3 because of lower system needs and lower costs of competitive supply-side resources;**
- **Added gas-fired rather than coal-fired resources to meet baseload needs, because coal costs have increased while gas costs have decreased;**
- **Selected a summer-only peak purchase to meet short-term summer peaking needs;**
- **Showed that adding transmission capacity was not cost effective; and**
- **Confirmed that environmental adders significantly increase customer prices.**

FINDINGS FOR MAJOR CASE GROUPS

Consistency with RAMPP-3

The RAMPP-4 cases that most closely resembled RAMPP-3 cases produced results that were consistent with the results of the RAMPP-3 cases. Thus RAMPP-4 confirmed the overall results of RAMPP-3.

Demand side management

The model selected the amount of DSM that was optimal for each case. Most of the cases had very similar amounts of DSM; i.e., the model's selection of DSM amounts tended to be unaffected by the variations between cases. The amount of DSM selected in the vast majority of the cases fell within 10 MWa of the base case over the first 10 years. The amount of DSM chosen varied more than 10 MWa when inputs were changed for load growth, DSM cost assumptions, gas prices and environmental adders.

Load growth caused the most variation in DSM selection. There was more than a 200 MWa difference between the medium-low and medium-high cases after the first 10 years. Changes in gas price escalation and environmental adders caused a variation of 50 to 75 MWa in the level of DSM selected by the end of the first 10 years.

For the action plan, the company adopted the amount of DSM selected in the case with DSM costs reduced by 15 percent, for three reasons: 1) The advisory group supported that case; 2) the difference between the base case and the case that was selected was only 10 MWa over the three-year action plan period; and 3) the extra 10 MWa caused no greater price impact than the amount of DSM from the base case.

Summer peak purchases

Summer peak drove the model's resource additions because, even though PacifiCorp's retail load is winter peaking, the company has more resources available to meet winter peak needs than summer peak needs.

Results of the model runs indicate that the company does not need summer peaking resources until 2002 unless load growth increases beyond the medium level of 2.0 percent. The cases that required summer peaking resources sooner (the no Hermiston cases, the no DSM case and the no turbine upgrade case) are unlikely to occur, or are cases that resulted from a modeling experiment (extension of some inputs into the end-effect years).

While summer peaking needs occur in 2002, additional resources for winter peaks and energy needs are not needed until 2003. The most cost-effective solution for the one year that has only summer peak needs is short-term summer-only capacity purchases on the wholesale market for 2002. The company does not have to make a decision on whether to pursue these resources until 2001, because the lead time for such contracts is less than a year. The action plan does not include a specific amount of summer peaking purchase or acquisition because it covers only the next three years (1996 to 1998).

Baseload resources

Under medium load growth and medium gas prices, PacifiCorp needs 635 MW of additional baseload resources in 2003 through 2005. Gas-fired baseload resources have a four-year lead time. Therefore, the company would not need to make a decision on baseload needs until 1999, which is after the three-year action plan period for RAMPP-4. The most prudent action for 1996 through 1998 is to carefully watch and evaluate load growth, gas prices, market conditions and opportunities that may develop.

PacifiCorp will continue to evaluate all gas-fired resource opportunities offered by developers and the wholesale power market. Increasing activity on the wholesale market and among project developers provide more cost-effective choices than in the past.

Load growth

A small change in projected load growth (of one percent) has a large effect on the need for new resources over the next 10 years. The medium-low load growth forecast resulted in adding 787 MW of retail load to the system by the year 2005; the medium forecast added 1,689 MW by 2005; and the medium-high forecast added 2,630 MW by 2005. However, the company does not need to add that amount of resource because it currently has a surplus. The company's existing surplus runs out after 2005 for medium-low load growth; in 2003 for medium load growth; and in 2000 for medium-high load growth.

The model chose the same resources — DSM, renewables and gas-fired —for all three levels of load growth. However, it called for the addition of those resources sooner for the medium-high load growth case (2.93 percent growth per year in winter MW) and later for the medium-low load growth case (1.06 percent growth per year in winter MW).

Gas Prices

Even though gas prices increase faster than inflation in the medium and high escalation cases, gas price has a minor effect on customer prices. This is probably because non-firm electricity prices increase at 80 percent of the escalation rate for gas prices. Changes in company costs from higher or lower non-firm revenues compensate for the change in costs due to higher or lower fuel prices. As long as the company is successful in the wholesale market, and non-firm market prices continue to correlate highly with gas prices, customers should not suffer higher electricity prices from higher gas prices.

Renewables

The capital cost of renewable resources must come down 65 percent from current levels before renewables are competitive with gas-fired resources. When the cost of renewables dropped to that level, the model chose renewables and reduced its selection of gas-fired resources, with little effect on the average price. However, renewable resources are not a cost-effective choice unless their costs decrease substantially.

Wholesale market variations

Variation in non-firm prices has a minor impact on the amount of new resources selected. They mainly affected the company's profitability from non-firm sales, and therefore the overall system costs and customer prices. The company makes more non-firm sales than non-firm purchases. Therefore, a 25 percent decrease in non-firm prices increased average customer prices by 2.3 percent; a 25 percent increase in non-firm prices decreased average customer prices by 2.0 percent.

Overbuilding

If the company overbuilds by 250 MW or 500 MW, average customer prices would be reduced if non-firm prices are relatively high and would increase if non-firm prices are low. Overbuilding by 250 MW would have little effect on average prices if non-firm prices remain at the base level; however, overbuilding by 500 MW with non-firm prices at the base level could increase average customer prices. Overbuilding does not necessarily cause higher prices; it depends on the level of non-firm prices.

Underbuilding

If the company underbuilds, the impact on average customer prices would depend on the price of power purchased on the wholesale market. For the three cases of underbuilding in RAMPP-4, the company assumed a high price for replacement purchased power to avoid underestimating the risk of underbuilding. As in the overbuilding cases, the average customer prices for the next 20 years in the underbuilding cases show an inverse relationship to the price of non-firm power. That is, low non-firm market prices result in higher average customer prices, and high non-firm prices result in lower average customer prices. This is because the company would be selling more non-firm power than it was buying for all but two of the 20 years.

Transmission

Results of the model runs confirmed that expanding transmission capacity is not a cost-effective choice at this time. The model selected the simulated "move" of an existing plant — the theoretical equivalent of expanding transmission — only when the cost of the conversion was reduced enough for the model to select it. However, that reduced cost is far less than the actual cost of adding to transmission capacity.

Results of the other two transmission cases showed that adding transmission capacity would have almost no effect on resource choices, but would increase average customer prices. Given these results, the company did not include a transmission action item in the RAMPP-4 action plan.

Environmental adders

The addition of environmental costs leads to reduced use of the existing system. When the model was given adder-adjusted prices of the company's existing coal-fired generation, it shut down production from the existing system and added new resources with lower adder-adjusted costs. The model increased non-firm purchases, because they carried adders for gas-fired resources that are lower than the adders for coal-fired resources.

The model relied heavily on gas-fired resources when the level of environmental adders was low; it relied more heavily on renewables when the adder level was high. The implementation of a major environmental adder, such as a significant pollution tax, would have the single highest impact on customer prices of all the inputs tested in RAMPP-4.

WHERE DO WE GO FROM HERE?

RAMPP-4 Action Plan

In developing the RAMPP-4 action plan, PacifiCorp focused on resource needs and opportunities for the next 10 years. Although the RAMPP process covers a 20-year planning horizon, with end effects for an additional 30 years, the company based action items on only the next 10 years, because of market and industry uncertainties.

The items included in the three-year action plan are intended to position the company to provide low-cost electric service to customers given a range of future load, resource and market uncertainties. The RAMPP-4 action plan includes the following activities:

Demand side resources

Achieve 23 MWa of installed cost-effective savings by 1996; 25 MWa by 1997; and 28 MWa by 1998.

Peaking resources

Evaluate alternative ways to meet peaking needs and pursue opportunities that meet system needs cost-effectively.

Gas-fired resources

Evaluate alternative ways to meet baseload needs and pursue opportunities that meet system needs cost-effectively. Under expected load growth, PacifiCorp does not need new baseload resources until 2003 or later.

Preparing for the future

Continue to implement cost-effective system improvements to the generation, transmission and distribution systems.

Pursue low-cost activities that will increase the company's knowledge about renewable resources.

Continue to evaluate clean coal technologies, including IGCC and fluidized bed for their ability to meet resource needs at low cost and in an environmentally friendly way.

Continue to evaluate resource acquisition opportunities as they occur.

Continue to be a low-cost provider and a successful competitor in the marketplace.

Continue to improve the RAMPP process and work to modify IRP to be a more effective tool.

Evolution of IRP

The integrated resource planning process will evolve as the electric utility industry becomes more competitive. PacifiCorp believes that:

- IRP under regulatory commission oversight makes sense for the non-competitive, regulated part of the business (e.g., retail customers who do not have competitive choices), but not for the competitive part (retail customers who do have competitive choices, and wholesale customers). IRP should be tailored to the part of the business that remains regulated.
- The term "least cost" should be more broadly defined to reflect changes in the marketplace. In the past, state utility commissions have tended to interpret least cost as the lowest total resource cost. Total resource cost includes utility cost, customer costs for DSM and non-energy benefits of DSM. Using TRC as the standard for planning leads to higher levels of DSM and higher customer prices than does a focus on utility costs and retail prices. The TRC standard also does not adequately reflect the reality of customer choice. Broadening the definition of least cost to incorporate customers' price concerns will make IRP more useful to both the utility and regulators.

- The changing market will bring an increasing need to keep competitive information confidential. As competition increases, IRP requirements will need to balance the need for adequate regulatory review of company planning with the utilities' need to keep proprietary information on company plans and strategies confidential.

- Given the fast-changing, competitive marketplace, utilities will need more flexibility in their IRP action plans. Utilities cannot commit to specific resource decisions years ahead of need because future opportunities are uncertain and ever-changing.

- Utilities will weigh short-term conditions more heavily than in the past. Current IRP assumes that existing customers will remain on the regulated utility's system for 10 and 20 years. However, in a competitive marketplace, customers may not stay on the utility's system that long; thus, the system may never receive the long-term benefits of resource investments such as DSM.

PacifiCorp believes a comprehensive discussion of the issues related to integrated resource planning can help all of the affected parties arrive at solutions that will make the process increasingly useful to utilities as well as regulators.

FOR MORE INFORMATION

If you would like additional copies of this Executive Summary, a copy of the full RAMPP-4 report or Appendix, or the RAMPP-3 documents that supplement RAMPP-4, please call (503) 464-5620.

PacifiCorp

RAMPP-4 Update

1997 IRP Report

December 1996

Recycled Paper

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PACIFICORP
PACIFIC POWER UTAH POWER

December 13, 1996

To: RAMPP Advisory Group Participants

Attached is your copy of PacifiCorp's RAMPP-4 Update Report (the 1997 IRP Report). The company has also sent copies to each of the state Commission offices and other interested parties. Attached is a copy of the cover letter included with the report sent to your particular state Commission office.

We anticipate the next RAG meeting will be toward the end of January or early February. We will be sending you a letter regarding that along with minutes from the November 8 RAG meeting and materials for review at the meeting. We anticipate these materials will be modeling results from the first group of sensitivities. The first group will include sensitivities on load growth.

If you have any questions regarding the Report or the RAG schedule, please call me (503) 464-5121. If members of your organization would like additional copies, please contact Kathee Murphy at (503) 464-5881.

Sincerely,

Nancy Esteb (km)

Nancy Esteb
Manager, IRP

NE/km
Enclosure

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PACIFICORP
PACIFIC POWER UTAH POWER

December 13, 1996

Julie Orchard, Commission Secretary
Utah Public Service Commission
Heber M. Wells Building, Fourth Floor
160 East 300 South
P.O. Box 45585
Salt Lake City, UT 84145-0802

Dear Ms. Orchard:

PacifiCorp is submitting this RAMPP-4 Update one year after filing RAMPP-4, which fulfilled IRP requirements. The purpose of the Update is to better assess changing market conditions and provide an up-to-date assessment of cost-effective DSM and the timing for resource decisions. Enclosed are six copies of the report.

The company is asking the Commission to review this submittal and acknowledge one key change in the RAMPP-4 action plan: changing the DSM goal for 1997 from 25 Mwa as identified in RAMPP-4 as cost effective, to 15.7 Mwa as identified in this Update as cost effective.

The Company would be pleased to meet with the commission to discuss the contents of the report. Please call me at (503) 464-5121 if you would like additional information.

Sincerely,

Nancy Esteb (km)

Nancy Esteb
Manager, IRP

NE/km
Enclosures

PacifiCorp

RAMPP-4 Update

1997 IRP Report

December 1996

Table of Contents

List of Tables and Graphs

Executive Summary

PacifiCorp completed its fourth integrated resource planning (IRP) cycle in November, 1995. To use more current information for planning, the company has developed this Update to the November, 1995 report.

Due to increasing competition and government actions, the electric utility industry is moving from regulated monopolies to competitive markets. That requires some changes in the IRP process.

IRP in a regulated monopoly world uses a long-range approach to anticipate resource needs, relying on a least-cost mix of DSM and power plants to meet those needs. That approach at PacifiCorp results in a report which is out-of-date by the time it is filed every two years.

PacifiCorp thinks there is a better way, retaining the basic elements of IRP, but modifying the process to result in a more timely analysis and reporting schedule. This Report is the first in what the company anticipates will be an annual process.

Six major events in 1996 have affected planning: FERC Orders, regional outages, ISO developments, Centralia emissions, Northwest Comprehensive Review, and California restructuring.

The company established benchmarks in its November, 1995 IRP report (load growth, gas prices, market prices, government actions, and renewable prices) to watch. They identify changes that would warrant a re-examination of its action plan. The only benchmark triggered was in market prices.

The company updated the input assumptions and data since the earlier report. The new base case shows a need for a new cogeneration unit in 2002 and 15.7 Mwa of DSM in 1997.

The only change the company is making in its action plan is a reduction in the DSM target for 1997. The new modeling identifies 15.7 MWa of DSM as being cost effective for 1997, rather than the 25 MWa identified as cost effective in modeling conducted almost two years ago. The company was active during 1996 on all of the elements in the RAMPP-4 action plan.

Introduction

PacifiCorp completed its fourth integrated resource planning (IRP) cycle, RAMPP-4, in November, 1995. RAMPP refers to PacifiCorp's Resource and Market Planning Program, its IRP process. To improve the process and base planning assumptions on more current information, the company has developed an Update to the RAMPP-4 Report. This Report summarizes the company's Update.[1] This Update Report is also titled "1997 IRP Report." The following explanation will clarify the logic behind that name.

The electric utility industry is at a crossroads of change between regulated monopolies and competitive markets. This is occurring primarily as a result of increasing competition and government actions. Customers want access to market-priced power, and other providers want to sell it to them. Government agencies, such as FERC, are changing the rules under which the industry operates. Federal and state legislation is helping restructure the industry, such as EPACT of 1992, and state laws that begin open access. Two immediate examples are New England and California.

PacifiCorp believes that the least cost planning process can help prepare for the changes brought by increasing competition and probable restructuring in the industry. Just as the company will need to be flexible and creative in the way it does business, it will need to be flexible and creative in the way it does IRP. PacifiCorp's IRP process will need to complement a competitive market and consider uncertainties in competition, regulation, government actions, and industry structure. Just as important, IRP will need to evolve to meet the needs of the company and other parties in a fast-changing and more competitive world.

It is not possible to discern what form (or forms) the electric utility industry of the future will take. The possibilities range from retention of service territories with increased wholesale competition to a model in which all customers have a choice of generation suppliers. Utilities could remain vertically integrated or disaggregate and form generation companies, transmission companies, and distribution companies, or combinations of those three structures. The experience of other industries that have transitioned from

[1] This Update Report does not include background information provided in the RAMPP-4 Report. If the reader does not have a copy of the RAMPP-4 Report, the company would be happy to send one. Please call (503) 464-5881.

monopoly to competition demonstrates that the forces of competition work swiftly. PacifiCorp believes modifying its IRP process can help prepare for the coming changes.

IRP in a monopoly regulated world focused on a long-range approach that anticipated resource needs and identified the least-cost method of adding DSM and power plants to meet those needs. It focused on total system costs rather than on customer prices. The action plan laid out specific resource acquisition activities the company would pursue over the next two or three years. That approach no longer fits today's realities. First, long lead times for resource and market decision-making are a thing of the past. A planning process that assumes long lead times for resource decisions does not meet the company's needs. Second, customers care about prices, not total system costs. And third, the company plans on using the market to meet any resource needs over the next several years. Opportunities develop in the market that require swift action.

IRP as traditionally conducted at PacifiCorp resulted in a report which was generally quite out-of-date by the time the company filed it every two years. This occurred because of the sequence of activities in each cycle, and the amount of analysis and review time required in each cycle. In order to prepare a full analysis of multiple cases to adequately evaluate uncertainty, the inputs had to be "frozen" before doing any of the computer runs. This freezing of the inputs typically occurred almost a year before publication of the final report. In a time of slow change in the industry, which allowed for long lead times for decisions, this was less of a problem than it is now. Given today's market realities and the need to make quick decisions, an out-of-date report is not very useful to the company.

PacifiCorp thinks there is a better way. That better way begins with a short annual report that updates the critical inputs and results of IRP work. This minimizes the time between freezing the inputs and filing a report of the key findings. This approach makes IRP a more continuous process, rather than being a static process that cannot reflect changing market conditions.

The following table outlines the elements of old-style IRP and what PacifiCorp is proposing as new-style IRP. Some of the elements are the same, while some are modified.

Old-Style IRP and RAMPP-4	New-Style IRP and Annual IRP Reports
Provide least-cost energy services to retail customers	Provide low-cost energy services to retail customers by minimizing prices
Consider a broad array of resources, including renewables and DSM, on an equal and consistent basis	Consider a broad array of resources, including renewables and DSM, on an equal and consistent basis
Consider uncertainties of different resources, future electricity demands, other factors	Evaluate risks of alternative resource strategies and uncertainties
Consider environmental effects of electricity production and transmission	Consider environmental effects of electricity production and transmission to minimize future risks
Ensure that transmission and distribution expansions are consistent with other planning needs	Help coordinate generation and transmission planning efforts
Avoid/reduce excess capacity while maintaining reliability	Evaluate the risks of alternative reserve levels while maintaining reliability
Ensure the utility meets its obligation to serve adequately and fairly its retail customers	Help smooth the transition to a more competitive industry
Increase public participation in utility planning	Assure an appropriate level of public participation in utility planning
Lead to decisions that are more widely accepted	Support new ways to approach public policy objectives
Biennial updating	Annual updating
One base case and sensitivities based on it	Base case and sensitivities based on it, and new updated base case
Transmission paths based on owned and contracted capacity	Transmission paths based on owned and contracted capacity, and on potential market availability
Minimal inclusion of market resources	Market resources in the portfolio of resources the model can select

Extensive report and appendices	Abbreviated report
Regular meetings and sharing of information with public advisory group	Regular meetings and sharing of information with public advisory group
Action plan focused on specific decisions and actions over next 2-3 years	Action plan focused on strategies for next few years

In PacifiCorp's new approach, each annual Report will include a summary of the results of sensitivities based on the prior base case, as well as a new base case. The sensitivities will examine ways critical uncertainties affect results. Because the annual Report will be published immediately after preparation of the new base case, it can use the latest information on the market and prices. The new approach reverses the sequence of activities in the old approach.

The old approach followed the following sequence and occured over two years:

- Update inputs, discuss with advisory group,
- Prepare base case, discuss with advisory group,
- Prepare sensitivities based on base case, discuss with advisory group,
- Issue draft report,
- Receive comments on draft report,
- Issue report.

The new approach follows a different sequence and occurs over one year:

- Prepare sensitivities based on fall base case (the base case prepared in the preceding fall), discuss with advisory group,
- Update inputs, discuss with advisory group,
- Prepare new base case, discuss with advisory group,
- Issue report.

A critical difference is the time span between preparing a base case of critical inputs and results, and issuing a report: that span is 10 months in the old approach and 2 months in the new approach.

This Update, the first annual report, does not include a summary of sensitivities because the full RAMPP-4 Report provided that information. However, the Report expected at the end of 1997 will include a summary of the sensitivity analyses performed in the first half of 1997, and subsequent annual reports will also include a summary of sensitivities. The typical annual cycle will be as follows, with the shaded area showing the same sequence as identified above and showing the content of annual reports (beginning with the one planned for the end of 1997):

July - August	Update modeling inputs and review changes with public advisory group
September - October	Prepare model run from the new base case and review results with public advisory group
November	Issue Report of new base case and sensitivities based on prior base case
January - June	Prepare sensitivities off of the September-October base case and review results with public advisory group
July - August	Update modeling inputs and review changes with public advisory group
September - October	Prepare model run from the new base case and review results with public advisory group
November	Issue Report

PacifiCorp believes this approach offers several advantages:

- Provides a more timely process through more frequent updating of key assumptions and results;

    1. Market conditions and the cost of alternative resources;
    2. The amount of DSM that is cost effective;
    3. Estimate of a decision year for acquisition of new resources.

- Preserves IRP, while allowing it to evolve, avoiding a time-consuming series of formal regulatory processes to change IRP;

- Links IRP more closely to the company's actual planning decisions, by updating more frequently and identifying DSM goals annually;

- Continues information access through RAG meetings and mailings;

- Provides a base run for avoided costs (as long as these continue to be prepared in conjunction with the IRP process); and

- Provides a benchmark for other studies.

The company does not expect that this approach is a "final" solution for IRP in a competitive world. It would not be fruitful, at this point in time, to anticipate an industry structure and re-design IRP to match that structure. It would inevitably be wrong about one or several key elements, resulting in planning requirements that again did not fit the real world. A better approach is to let IRP evolve through modifications that best meet each utility's needs while providing information needed by regulators and the public.

The next section on significant events in 1996 demonstrates the changing nature of the industry and the need for planning flexibility.

Significant Events in 1996

Significant events in 1996 that have had an effect on PacifiCorp's planning include the following:

- The Federal Energy Regulatory Commission (FERC) Orders 888 and 889 and the company's response to those Orders;

- Two outages that affected much of the western United States;

- Beginning the process to form a small number of independent system operators (ISOs) to operate large portions of the Western System Control (WSCC) transmission system;

- Resolution of emission reductions at the Centralia plant;

- The Northwest Comprehensive Review; and

- California restructuring.

The Federal Energy Regulatory Commission (FERC) Orders 888 and 889 and the company's response to those Orders

To increase wholesale competition and open transmission systems in the United States electric industry, the FERC issued a Notice of Proposed Rulemaking (NOPR) in March, 1995, regarding open-access transmission. Orders 888 and 889, issued in April 1996, were the result of this NOPR. The Orders mandated changes that broadly restructure the electric utility industry: 1) utilize open-access transmission tariffs for their own wholesale sales, 2) allow electronic acquisition of transmission service through Open Access Same Time Information Systems (OASIS) sites, and 3) conduct transmission business in accordance with a filed Standard of Conduct.

PacifiCorp is actively implementing Orders 888 and 889. On August 7, 1995, PacifiCorp became one of the first electric utilities to offer transmission service under an open-access transmission service tariff. In addition, PacifiCorp has been electronically selling transmission services through its Electronic Information Network (original name of the company's OASIS site) on the Internet since October 1, 1995.

FERC requires that by July 9, 1996, all public utilities submit informational filings showing they have unbundled wholesale services and charges for all requirements contracts and/or tariffs that previously specified bundled rates. PacifiCorp's open-access transmission tariff became effective on July 9, 1996. Also on July 9, public utilities that use their transmission facilities for wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission for such sales and/or purchases under the final rule pro forma tariff. After July 9, utilities no longer had to demonstrate any lack of market power in generation when requesting authority to charge market-based rates for power generated from facilities yet to be constructed. Transmission owners can also submit non-pro forma tariffs for commission consideration after July 9. PacifiCorp has complied with these requirements.

Order 889 requires that utilities provide real-time information on their transmission availability and prices so that buyers and sellers know what space is available and what the price will be. All potential users, including the owner of the transmission facilities, must access a utility's transmission under the same terms and conditions. In response to Order 889 PacifiCorp will implement a thirty-day test of its OASIS site in early December, 1996, with full implementation by January 3, 1997. Additionally, as required by Order 889, PacifiCorp will file with the FERC its Standard of Conduct.

The FERC Orders have had two significant impacts on PacifiCorp planning. One is a change in assumed capacities on transmission paths. The Modeling Inputs section below discusses this. A second change is due to the Code of Conduct. There will now be greater separation within the company between the transmission planning, operation, and scheduling staff and those who use the transmission system. This may result in some restrictions on free information flow between the two groups.

Two outages that affected much of the western United States

A significant power outage occurred at 1:25 p.m., PDT on July 2. A combination of unusual operating conditions contributed to the disturbance, including record-setting power demands, near record-setting hydro generation, high power transfers between the Pacific Northwest and California, and high coal-fired generation in Wyoming and Utah. While this was occurring, a line sagged too close to a tree in southeastern Idaho, creating a short circuit and causing the line to disconnect automatically. A protective device on a parallel line mis-interpreted the short circuit and disconnected its line. Loss of the two lines activated an automatic procedure to shut down two large generating units at the Jim Bridger power plant; otherwise, the generators' output would overload the remaining transmission lines.

Bulk electric systems in the West are designed and operated to be able to absorb the stresses of such a combination of events. In this case, however, the initial event began a sequence rippling across the entire western power grid, interrupting service to more than two million customers in 14 states.

PacifiCorp crews conducted an air search along 230 miles of transmission lines, followed by a ground search when the air search could not determine the cause of the disturbance. The company also participated in a study of the cause of the outage. The study report identified 21 action items to reduce the chances of similar outages. WSCC members and work groups will address these items.

On August 10, 1996, the second major outage of the summer occurred, triggered by the loss of several key transmission lines and generating facilities on the Bonneville Power Administration system. Both the July 2 and August 10 outages have raised concerns about the amount of power being transferred across the Western interconnected system. With 88 member utilities and more than 112,000 miles of transmission lines across 14 states, the Western system covers the most territory of any of the continent's nine regional grids. Today, the 88 members who operate the system do so through voluntary agreements. As competition results in more companies using the transmission lines, the biggest challenge facing the system isn't the ability to handle the increased amount of electricity. The challenge is determining who has the responsibility and authority to coordinate activities between operators to insure safe and reliable service.

The impact of the outages on PacifiCorp's planning has been to pay more attention to assumptions about capacity estimates for transmission paths.

Beginning the process to form a small number of independent system operators (ISOs) to operate large portions of the Western System Control (WSCC) transmission system

Management of the transmission system by a private, independent operator regulated by FERC could enhance reliability and move power more efficiently. Australia and England, which have more deregulated industries, have already moved in this direction. PacifiCorp has led an effort among Northwestern investor-owned utilities to relinquish the operation of their transmission systems to an independent operator. On July 12, 1996, PacifiCorp and six other utilities announced that they signed a memorandum of understanding (MOU) to develop a proposal for an independent grid operator that would manage member companies' transmission systems. The group has named it IndeGO. The six other members of IndeGO are Portland General Electric, Puget Power, Idaho Power, Montana Power, Washington Water Power and Sierra Pacific. IndeGO membership is open to any public or private utility or agency. Subsequently, Tacoma City Light, Chelan PUD, and the Bonneville Power Administration have signed the MOU.

IndeGO would manage all members' transmission systems to ensure reliability and guarantee open access. The new organization would ensure non-discriminatory open access to electricity transmission facilities in compliance with recent FERC rulings. IndeGO would have overall responsibilities for planning, coordination of maintenance, scheduling use of the transmission system, and pricing of transmission service, subject to FERC approval. Owners will be compensated for use of their system by IndeGO. Work groups are studying what functions IndeGO will perform, how it will be operated and how member utilities' employees will interact with IndeGO.

PacifiCorp plans to file the IndeGO proposal with FERC in the spring of 1997. The group anticipates operation would begin in July, 1997

The impact of IndeGO on PacifiCorp's planning has been to pay more attention to the uncertainty of transmission paths. When entities such as IndeGO control use of transmission paths, the capacity available to the company may change.

Resolution of emission reductions at the Centralia plant

A group of utility and government agency representatives began meeting last January to lower emissions at the Centralia plant while keeping it economically feasible to continue operating the plant and adjacent Centralia mine in southwest Washington state. The collaborative group includes plant owners, the National Park Service, the USDA Forest Service, the U.S. Environmental Protection Agency, the Washington Department of Ecology, the Southwest Regional Air Pollution Control Agency and the Puget Sound Air Pollution Control Authority. PacifiCorp owns 47.5 percent of the 1,340 MW plant and operates it for the seven other partners. The company also owns and operates Centralia mine. The company supports the group's two-stage plan to install two scrubbers that will reduce sulfur dioxide (SO2) emissions at the Centralia plant by 90 percent. Construction of the first scrubber would begin in 1997; construction of the second scrubber would begin in 2002 and be completed by 2007. The plan will be submitted to the state of Washington Southwest Air Pollution Control Authority, and approval could come in spring of 1997.

The impact of the Centralia agreement on PacifiCorp's planning has been to solidify the input assumptions about the existing system.

The Northwest Comprehensive Review

The Northwest Comprehensive Review 20-member steering committee, appointed by the governors of Idaho, Montana, Oregon and Washington, includes representatives from public and private utilities, industrial customers and public interest and consumer groups. Their purpose is to recommend changes to transform the Bonneville Power Administration system (Bonneville, or BPA). The transition to a more competitive electric industry in the Northwest is complicated by the presence of Bonneville. It is a major factor in the region's power industry, supplying approximately 40 percent of the power sold in the region and controlling more than half the region's high-voltage transmission. While Bonneville benefits from marketing most of the region's low-cost hydroelectric power, it has high fixed costs due to past investments in nuclear power, and the Columbia River salmon recovery program. As a wholesale power supplier, Bonneville is already fully exposed to competition and is struggling to keep its costs close to market. Many are asking what the appropriate role is for Bonneville in a competitive market.

The steering committee has been meeting throughout 1996. Their five area of study are: 1) federal power marketing; 2) conservation, renewable resources and low-income energy services; 3) competition and consumer choice; and 4) federal transmission. They have agreed that BPA should be legally split into two entities and that the transmission portion of the agency should become part of a regional integrated grid operator (IGO). The committee finished deliberations on the draft recommendations in August; it then went out for public comment at meetings around the region and will be sent to the four Northwest governors in early December.

The company's interest in the Comprehensive Review is related to PacifiCorp's standing as Bonneville's second largest power and transmission customer, and to the strong role both play as competitors in the wholesale power market. The final report is likely to guide future state and federal legislation on industry restructuring.

The company believes the Review must address several key issues: 1) identifying a model for Bonneville that maintains the regional benefits of the federal hydropower system while helping to ensure that it can repay its federal debt; 2) identifying an appropriate role for Bonneville, a federal power marketing agency, in the new competitive environment ; 3) identifying a mechanism that recognizes that society values conservation and renewable energy and finds a way to provide it in a competitive marketplace; and 4) identifying Bonneville's role as a transmission provider

The impact of the Northwest Comprehensive Review on PacifiCorp's planning has been to magnify the importance of the changing nature of the industry environment in which planning occurs.

California restructuring.

On August 28, 1996, the California legislature passed AB 1890, a multi-step plan to restructure the electric utility industry. The bill gives all California customers the right to purchase power from other suppliers as early as January 1, 1998. It provides a public goods charge for continued funding of DSM and other public purposes. It ratifies the creation of a power exchange and a California independent system operator (ISO). The utilities would transfer operational control of their transmission facilities to the ISO, which would oversee power deliveries. Implementation of this legislation and related commission policies is the subject of numerous proceedings at the CPUC and FERC, which will extend through most of 1997.

AB 1890 contains many provisions related to prices and transition costs to meet the situation of the three large electric utilities. Provisions include a general price freeze and a price reduction for residential and small commercial customers that would be financed based on utilities' transition costs. The prices of the three large utilities are substantially above the national average and their estimates of stranded costs are large. These utilities have identified substantial cost reductions they believe they can achieve over the next four to five years. PacifiCorp's prices in California are already below the national average. Implementing a price reduction and a price freeze may, in effect, penalize PacifiCorp for past efficiencies. The company is currently discussing implementation issues related to the California service area with California Commission staff.

The impact of California restructuring on PacifiCorp's planning has been to highlight the uncertain nature of the future of the industry.

Public Process

The company held five public advisory group meetings as it developed the updating of input assumptions for this Update:

April 26, 1996
June 13, 1996
August 9, 1996
September 27, 1996
November 8, 1996

Additional meetings will occur in 1997 to plan work on scenarios and review the modeling results from running those scenarios. This will allow all of the parties to test model results under a variety of assumptions. The next annual report, expected at the end of 1997, will include a summary of the results of the scenarios run during the first half of 1997. These scenarios will be similar to the sensitivity cases run as part of RAMPP-4. The company will be especially alert to any results that reveal a different pattern from the findings of the RAMPP-4 cases.

Benchmarks

In the RAMPP-4 Report, the company identified several benchmarks to guide it in its decision making. The company recognized that a change in any of these benchmarks would warrant a re-examination of the RAMPP-4 action plan. The following discussion reviews the status of each of the benchmarks.

Load Growth Benchmarks

- If load growth for 1995 is below 1.5 percent for the system as a whole or for one geographic area of the system, or
- If load growth for 1995 is above 2.5 percent for the system as a whole or for one geographic area of the system.

The RAMPP-4 action plan set benchmarks for load growth to be within a range of 1.5 percent to 2.5 percent. Actual growth in 1995 was 0.2 percent due to a wet year, which caused irrigation sales to be down 27 percent from 1994 and a faster-than-anticipated reduction in the gas and oil extraction load in southwestern Wyoming, where the fields are in the "blowdown" phase. However, 1996 load growth will be higher (3.8 percent as of September, 1996), with irrigation sales up 24 percent and the gas and oil extraction load leveling off. Consequently, the 1994 to 1996 average load growth will be approximately 2 percent per year, which is on track with the RAMPP-4 medium load forecast.

Gas Price Benchmarks

- If accepted gas price forecasts indicate prices will rise by 0 percent real escalation or lower per year, or
- If accepted gas price forecasts indicate prices will rise by 4 percent real escalation or higher per year.

Accepted gas price forecasts indicate prices will rise by more than 0 percent real escalation, but less than 4 percent real escalation. As discussed below under the topic of updating gas prices for this Report, accepted gas price forecasts are that gas prices will rise by an average of 1.5 percent real per year over the study period. This is neither less than 0 percent nor more than 4 percent.

The company did not include a benchmark for the beginning price of gas (the price in the first year of the study period). From RAMPP-4 to the Update, the beginning price fell 17 percent on the west side of the system and 11 percent on the east side. This change is another reason the company prefers an annual updating for its IRP process.

Market Price Benchmarks

- If non-firm market prices decrease by 25 percent or more from their 1995 levels, or
- If non-firm market prices increase by 25 percent or more from their 1995 levels.

Non-firm market prices have not decreased by 25 percent or more from their 1995 levels, nor have they increased by 25 percent or more. Table 1 shows non-firm market prices (referred to in this Update as short-term market prices) for RAMPP-4 and for this Update. The line in the table showing average indicates a 57/43 split. That is consistent with the model, which places 57 percent of each week's hours in the high-load hour period, and 44 percent in the low-load hour period.

Average Market Prices: RAMPP-4 versus RAMPP-4 Update
Table 1

	RAMPP-4	Update	% Change
High Load Hours	19	18	(5%)
Low Load Hours	16	10.2	(36%)
Average (57/43)	17.7	14.6	(18%)

The change in prices for low-load hours illustrates the need for timely updating of IRP planning. Although pricing for high-load hours changed little since modeling inputs were frozen for RAMPP-4, they have changed substantially for low-load hours. The section below on market price input changes addresses the reasons for this pattern.

Government Benchmark

- If the federal government passes some form of CO_2 emissions controls or tax.

As of November 1996, the federal government has not passed some form of CO_2 emissions controls or tax, and the company does not expect such legislation in 1997.

Renewable Benchmark

- If one of the renewable technologies achieves costs that are within 10 percent of the cost of acquiring gas-fired resources at the time a decision would be made.

As of November 1996, none of the renewable technologies has achieved costs that are within 10 percent of the cost of acquiring gas-fired resources.

Since none of the benchmarks occurred except the price of market power during low-load hours (and the beginning price of gas), the company believes most of the RAMPP-4 action plan is still valid. However, new modeling reveals that the cost-effective amount of DSM has changed. The section below on modeling results discusses this change and the reasons for it.

Modeling Inputs

The Model

As with RAMPP-3 and RAMPP-4, the company continues to use the IPM model from ICF Resources, Inc. for its IRP modeling work. There were no code changes in the model between RAMPP-4 and the Update.

Reserve Margin

The company changed the planning reserve margin from 12 percent in RAMPP-4 to 10 percent in the Update. The company adopted 10 percent because access to market power to meet any short-term capacity needs results in less need for reserves.

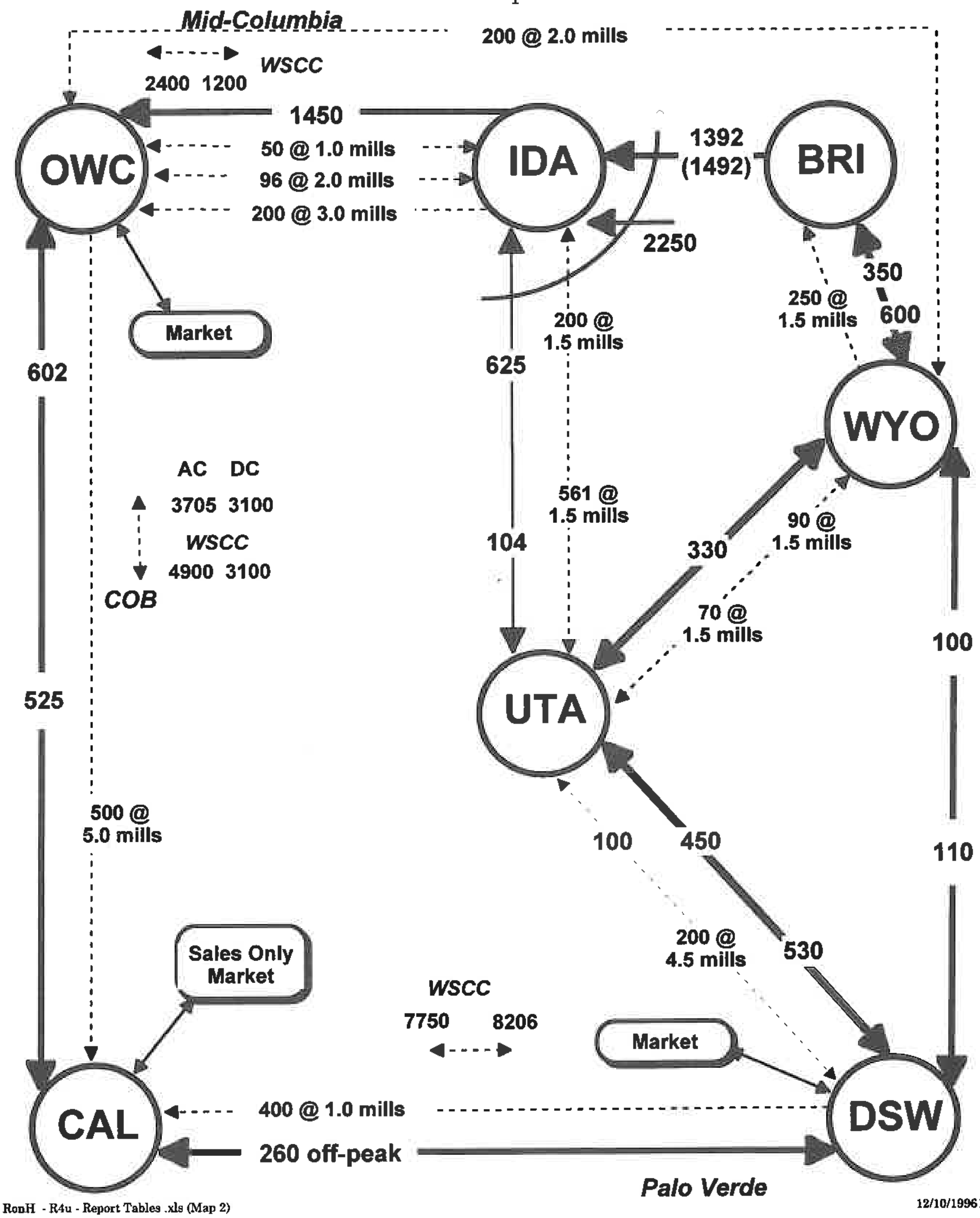
Geographic Areas and Transmission Limits

Map 2 shows the geographic representation of PacifiCorp's system as input into the model. The arrows and numbers indicate the transmission paths and the amount of power PacifiCorp can move along those paths. A designation such as "50 @ 1.0 mills" indicates that the model could move an additional 50 MW of power at a price of 1 mill/kWh. As with RAMPP-4, the model includes the following geographic areas:

- OWC: represents load areas in Oregon, Washington, California, and Montana; as used in this Report, it signifies the western side of the PacifiCorp system;
- CAL: represents the California market;
- BRI: represents the Bridger interconnection;
- WYO: represents load areas in eastern Wyoming;
- UTA: represents load areas in western Wyoming and in Utah; and
- DSW: represents the Desert Southwest market.

Geographic Regions and Transfer Capabilities

Map 2



RonH - R4u - Report Tables .xls (Map 2) 12/10/19961:55 PM

The primary change to the specification of geographic areas and transmission limits was the creation of a new region in the Idaho area (indicated on Map 2 as IDA). This split the RAMPP-4 Utah load into a Utah area and an Idaho area. The transmission paths are now from Bridger to Idaho and from Utah to Idaho. This allows the model to capture a significant transmission constraint between Utah proper and the southern Idaho load.

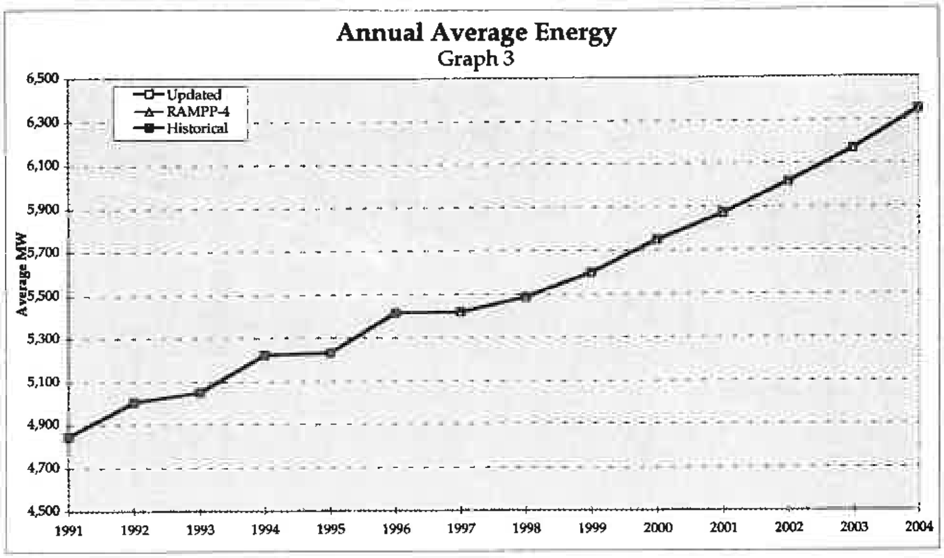
In the past, transmission planners typically used the concepts of firm and non-firm transmission. However, with recent changes in the rules that apply to transmission operations, these distinctions are less applicable. A more appropriate approach is to think in terms of probabilities of a transmission path being available. The company is trying to recognize the new realities by using a step function in the modeling of transmission limits among the geographic areas used in RAMPP modeling. The company included in the model a transmission capacity between each of the geographic areas, and additional capacity available for a price. The map shows the model inputs for prices of additional capacity. For example, from IDA to OWC 1450 MW of transmission capacity is available. Additional transmission capacity of 50, 96, and 200 MW was input into the model at prices of 1, 2, and 3 mill/kWh, respectively.

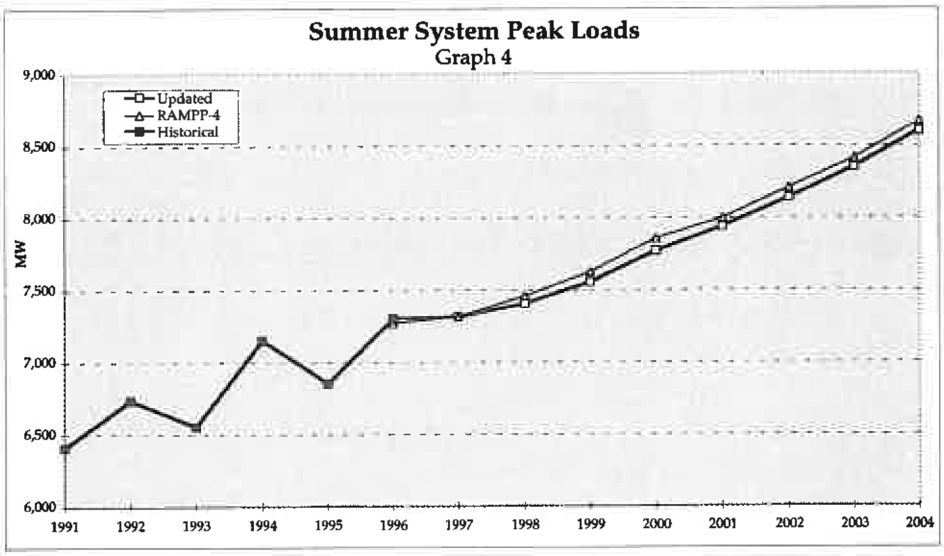
Load Forecast

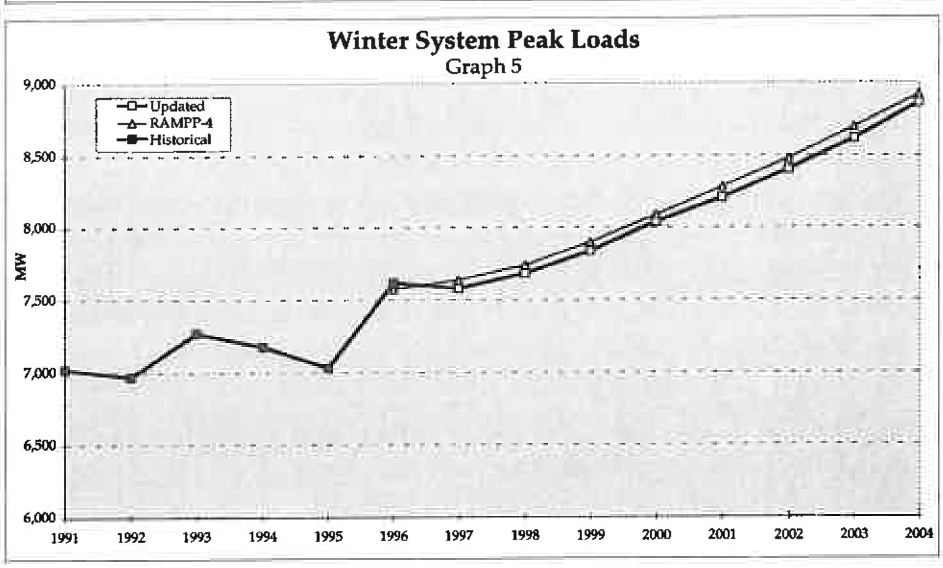
When deciding whether to revise the load forecast for the Update, the company considered two factors:

- How is the RAMPP-4 load forecast performing? As discussed above in the section on Benchmarks, it is on track.
- Have there been any significant changes in the long-term economic forecast used as a basis for the RAMPP-4 load forecast? The answer is no, as employment is now forecast by DRI to grow at 1.1 percent per year versus 0.9 percent in the DRI forecast used for RAMPP-4, and gross domestic product (GDP) is now forecast to grow at 1.9 percent per year versus 2.0 percent in the earlier forecast.

Since the RAMPP-4 load forecast is tracking well and the expected long-term economic growth is about the same, the Update energy load forecast is the same as the RAMPP-4 forecast.


Annual Average Energy
Graph 3
Updated
RAMPP-4
Historical
Average MW
6,500
6,300
6,100
5,900
5,700
5,500
5,300
5,100
4,900
4,700
4,500
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004


Summer System Peak Loads
Graph 4
Updated
RAMPP-4
Historical
MW
9,000
8,500
8,000
7,500
7,000
6,500
6,000
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004


Winter System Peak Loads
Graph 5
Updated
RAMPP-4
Historical
MW
9,000
8,500
8,000
7,500
7,000
6,500
6,000
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004

While the aggregate energy load forecast is the same, the company made several improvements to the load forecast for this Update:

- Adjustment of load growth rates for each geographic area to reflect recent history and expectations for the future. The load growth forecast for OWC was reduced from an average of 2.1 percent to 1.8 percent per year for the 20-year forecast horizon; Wyoming was reduced from 2.1 percent to 1.5 percent per year, and Utah was increased from 2.3 percent to 2.8 percent per year.

- Addition of a fourth load area for Idaho to recognize a potential transmission constraint. The discussion above of changes to geographic areas and transmission limits includes this.

- Updating of load factors (annual summer and winter peak loads versus average energy loads) to reflect the average of the past five years. Applying the load factors to the forecast annual energy produces the forecast summer and winter peak loads. Recent history resulted in increasing the load factors (decreasing the peak forecasts).

- Updating the hourly load shapes used in the IRP model to reflect the 1995 actual load shape.

- Including the market transformation portion of DSM in the updated load forecast.

Graphs 3, 4, and 5 show the results of updating the load forecast, as well as historical loads from 1991. There is only one line in Graph 3, because the forecast for energy did not change from RAMPP-4 to this Update. Graphs 4 and 5 show two lines beginning in 1996: one for RAMPP-4 and one for the Update. For both summer and winter peaks, the Update peaks are slightly lower, indicating a slight increase in the system load factor.

The company also updated the hourly load profiles and the load duration curve definition.

Existing System

Table 6 shows the results of the company's updating of the data inputs on the existing system. It shows the year-by-year amounts of summer capacity available from each of the company's plants. In the following discussion, all of the MW figures listed are for summer capacity.

Existing System
Summer Capacity (MW)

Table 6, Page 1 of 2

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
Thermal Plants													
Carbon 1,2	175	175	175	175	175	175	175	175	175	175	175	175	175
Centralia 1,2	636	636	636	636	636	636	636	636	636	636	636	636	636
Cholla 4	380	380	380	380	380	380	380	380	380	380	380	380	380
Colstrip 3,4	144	144	144	144	144	144	144	144	144	144	144	144	144
Craig 1,2	165	165	165	165	165	165	165	165	165	165	165	165	165
Dave Johnstn 1,2,3,4	772	772	780	780	780	780	780	780	780	780	780	780	780
Gadsby 1,2,3	235	235	235	235	235	235	235	235	235	235	235	235	235
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78	78	78
Hermiston	454	454	454	454	454	454	454	454	454	454	454	454	454
Hunter 1,2,3	1,044	1,044	1,044	1,044	1,044	1,044	1,044	1,044	1,044	1,044	1,044	1,044	1,044
Huntington 1,2	885	925	925	925	925	925	925	925	925	925	925	925	925
James River	52	52	52	52	52	52	52	52	52	52	52	52	52
Jim Bridger 1,2,3,4	1,387	1,387	1,387	1,387	1,387	1,387	1,387	1,387	1,387	1,387	1,387	1,387	1,387
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton 1,2,3	700	700	700	700	700	700	700	700	700	700	700	700	700
Wyodak	268	268	268	268	268	268	268	268	268	268	268	268	268
Total Thermal	7,375	7,415	7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423
Renewables													
Blundell Geothermal	23	23	23	23	23	23	23	23	23	23	23	23	23
BPA Peaking	1,100	1,100	1,100	925	925	925	925	925	925	925	925	925	925
BPA Supp Capacity	12	10	5	5	4	4	-	-	-	-	-	-	-
Hydro Idaho	54	54	54	54	54	54	54	54	54	54	54	54	54
Hydro Pacific	922	922	922	922	922	922	922	922	922	922	922	922	922
Hydro Utah	36	36	36	36	36	36	36	36	36	36	36	36	36
Mid-Columbia	400	400	400	400	400	400	400	307	307	186	186	36	36
T&D Eff PPL	18	23	28	32	37	42	44	47	49	52	61	70	70
T&D Eff UPL	9	11	13	16	18	20	22	23	25	26	29	32	32
Water Budget	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	-	-	6	6	6	6	6	6	6	6	6	6	6
Total Renewables	2,573	2,578	2,586	2,418	2,424	2,431	2,431	2,342	2,346	2,229	2,241	2,103	2,103
Existing Generation	9,948	9,993	10,009	9,841	9,847	9,854	9,854	9,765	9,769	9,652	9,664	9,526	9,526
Purchases													
APS Sea (Purch/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Sea (Sale/Exchange)	(101)	(274)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Capacity	68	68	68	68	68	68	68	68	68	68	68	68	68
Black Hills Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store (Purch/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store (Sale/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Southern Oregon	50	50	-	-	-	-	-	-	-	-	-	-	-
BPA Spring (Purch/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Spring (Sale/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Summer (Purch/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Summer (Sale/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
Carbon (Acme)	-	100	100	100	100	100	100	100	100	100	100	100	100
CSPE	45	39	19	18	18	16	-	-	-	-	-	-	-
Deseret	275	275	275	275	275	-	-	-	-	-	-	-	-
Gem State	22	22	22	22	22	22	22	22	22	22	22	22	22
Grant County	14	14	14	14	14	14	14	14	14	14	14	14	14
Idaho Load Control	150	150	150	150	150	150	150	150	150	150	150	150	150
Interruptible Rep	-	-	-	-	-	-	-	-	-	-	-	-	-
IPC	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
PGE Cove	3	3	3	3	2	2	2	2	2	2	2	2	2
QF Idaho	22	22	22	22	22	22	22	22	22	22	22	22	22
QF NW	102	102	102	102	102	102	102	102	102	102	102	102	102
QF UPL	57	57	57	57	57	57	57	57	57	57	57	57	57

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Existing System
Summer Capacity (MW)

Table 6, Page 2 of 2

San Juan Unit 4	21	21	21	21	21	21	21	21	21	21	21	21	-
SCE Winter	-	-	-	-	-	-	-	-	-	-	-	-	-
So Idaho (Purch/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
So Idaho (Sale/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Basic	50	50	50	50	50	50	50	50	50	50	50	50	50
Tri-State (Purch/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State (Sale/Exchange)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	-	-	-
USBR Greenspring	18	18	18	18	-	-	-	-	-	-	-	-	-
WWP	50	-	-	-	-	-	-	-	-	-	-	-	-
WWP Seasonal (Purch/Exch)	50	50	50	50	50	50	50	50	50	50	-	-	-
WWP Seasonal (Sale/Exchange)	-	-	-	-	-	-	-	-	-	-	-	-	-
WWP Summer Purchase	150	150	150	150	150	150	150	-	-	-	-	-	-
Purchased Power	1,147	1,191	1,121	1,120	1,100	823	808	658	658	658	608	608	587
Total Resources	11,095	11,184	11,130	10,961	10,947	10,677	10,662	10,423	10,427	10,310	10,272	10,133	10,112

Sales													
APPA	80	80	80	95	-	-	-	-	-	-	-	-	-
APS Seasonal Sale	175	-	-	-	-	-	-	-	-	-	-	-	-
Azusa	-	10	-	-	-	-	-	-	-	-	-	-	-
BHP Steel	25	25	25	25	25	-	-	-	-	-	-	-	-
Black Hills 1996	10	15	25	30	30	30	-	-	-	-	-	-	-
Black Hills Load	75	75	75	75	75	75	75	75	75	75	75	75	75
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
CDWR	100	100	100	100	100	100	100	100	-	-	-	-	-
Cheyenne	128	130	131	133	-	-	-	-	-	-	-	-	-
Clark County PUD	149	203	99	99	99	-	-	-	-	-	-	-	-
Colockum	-	-	-	-	-	-	-	-	-	-	-	-	-
ESI Kaiser	100	100	100	-	-	-	-	-	-	-	-	-	-
EWEB	50	50	50	50	-	-	-	-	-	-	-	-	-
Glenbrook	-	-	-	-	-	-	-	-	-	-	-	-	-
Hinson	76	76	76	76	-	-	-	-	-	-	-	-	-
Interruptibles	-	-	-	-	-	-	-	-	-	-	-	-	-
Nevada 1	140	140	-	-	-	-	-	-	-	-	-	-	-
Okanogan	5	5	5	5	5	-	-	-	-	-	-	-	-
Pan Energy	100	90	-	-	-	-	-	-	-	-	-	-	-
PECO	100	100	-	-	-	-	-	-	-	-	-	-	-
PNGC	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCol	176	176	176	176	176	176	176	176	176	176	176	176	176
Puget 2	200	200	200	200	200	200	200	-	-	-	-	-	-
Redding	50	50	50	50	50	50	50	50	50	50	50	-	-
SCE OWC	100	100	100	100	100	100	100	100	100	100	-	-	-
SCE Utah	100	100	100	100	100	100	100	100	100	100	-	-	-
Sierra 1	75	75	75	75	75	75	75	75	75	75	75	75	75
Sierra 2	75	75	75	75	75	75	75	75	75	75	75	-	-
SMUD	100	100	100	100	100	100	100	100	100	100	100	100	100
Springfield	45	45	45	45	45	45	45	45	45	45	45	45	-
UMPA 1	8	8	8	8	8	8	8	8	8	-	-	-	-
UMPA 2	4	11	14	19	21	25	25	25	25	25	25	25	25
WAPA 1	100	100	44	44	33	33	33	33	-	-	-	-	-
WAPA 2	75	75	75	75	75	75	75	75	-	-	-	-	-
WAPA Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Sales	2,582	2,648	2,369	2,296	1,933	1,808	1,778	1,578	1,370	1,362	1,112	987	942

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Changes in plant capacities in 1997 from RAMPP-4 to the Update are as follows:

- Cholla 4 capacity decreased from 401 to 380 MW;
- Hunter units 1, 2, and 3 decreased from 1112 to 1044 MW;
- Huntington units 1 and 2 increased from 867 to 885 MW;
- Jim Bridger units 1, 2, 3, 4 decreased from 1396 to 1387 MW;
- Naughton units 1, 2, 3 increased from 675 to 700 MW;
- Wyodak increased from 256 to 268 MW.

The net result of these changes in plant capacity was an increase of 43 MW in summer capacity for 1997. The changes are similar for subsequent years. Most of these changes were due to revisions in the turbine upgrade schedule.

RAMPP-4 included 122 MW of QF contracts. That was the same data as RAMPP-3. For this Update the company completely reviewed all of its QF contracts to re-evaluate assumptions about their contribution to summer and winter peaks. The result of that re-evaluation was an increase in QF contribution to peaks. This Update used 180 MW for QF contribution to the summer peak. That number stays constant throughout the study period.

RAMPP-4 assumed 10 MW of wind capacity in 1997 and beyond; this Update assumes only 6 MW. This is due to the indefinite postponement of the Columbia Hills wind project. As in previous RAMPPs, wind and QF capacity amounts used in the model are the capacity available at the time of the summer peak, not the name-plate capacity for the plants.

In RAMPP-4 the company assumed that 150 MW of capacity from simple-cycle combustion turbines (SCCTs) in Arizona Public Service Company's area would come on line. The company analyzed its needs and cost alternatives, and determined that these CTs were not a cost-effective choice at this time. As a result of that review, the company has now indefinitely postponed those CTs. Therefore, the Update does not include them.

Hermiston capacity increased from 434 to 454 MW. Hermiston came on-line in the summer of 1996, and operating experience shows that its capacity will be higher than first estimated.

Coal costs have declined slightly for existing plants, and operation and maintenance (O&M) costs have also declined slightly.

The net result of the above changes is an increase in resources for each year of the study period. For 1997, RAMPP-4 anticipated 10,739 MW of summer capacity from the existing system and purchased power contracts; this Update shows 11,095 MW.

Demand-Side Resources

For this Update, the company input into the model DSM costs that were 15 percent less than the company's true estimate of those costs. The 15 percent reduction consists of 10 percent to reflect non-quantified benefits of DSM and 5 percent for transmission and distribution benefits of DSM. This is consistent with Case #13 from RAMPP-4, which the company used to develop the RAMPP-4 action plan. Case #13 also decreased DSM costs by 15 percent for modeling purposes.

In RAMPP-4 the company introduced the concept of DSM bundles. Each bundle included several DSM measures with similar costs. The model input was the average cost for the measures in each bundle. This approach allowed the model to select the amount of DSM that was cost effective.

For the Update the company expanded this approach. Table 7 shows the bundles for each of the sectors: commercial, industrial, irrigation, and residential. Commercial and industrial DSM measures fell into eight bundles for each segment, with the first three bundles including most of the resource. The 8th bundle contains all resources above 30 mills/kWh. Only one irrigation bundle was necessary for each state. Residential DSM required one bundle for each state for the Super Good Cents program, and two bundles for each state for appliances. The appliance measures are grouped according to their cost.

The table also shows the fully loaded cost for each of the bundles and the amount of DSM potential over the study period. The company did not change the DSM potential between RAMPP-4 and the Update. The total amount of DSM potential offered to the model for the entire 20 year study period was 672 MWa. The amount of DSM potential for 1997 was 29 MWa. The model selected 15.7 MWa for 1997.

The company updated commercial measure costs using the CEC DEER Database and measure savings. ASHRAE 90.1 standards was the program baseline. The load forecast for this Update includes the impact of the change-over from 40 to 34 watt lamps for existing commercial buildings; RAMPP-4 included savings from this change-over in the DSM potential rather than in the load forecast. The

DSM Total Costs and Savings Potential By Resource Bundle

Table 7, Page 1 of 3

Program Descriptor	Resource Bundle Lower Limit	Resource Bundle Upper Limit	Levelized 50 Year TRC (MILLS/KWH) *	1997-2017 Savings MWA
			15%	
C-COM-EXISTING-1-OWC	-100	8	2	19.0
U-COM-EXISTING-2-OWC	8	15	13	9.7
U-COM-EXISTING-3-OWC	15	20	18	7.6
U-COM-EXISTING-4-OWC	20	22	22	3.6
U-COM-EXISTING-5-OWC	22	25	24	2.0
U-COM-EXISTING-6-OWC	25	27	27	0.3
U-COM-EXISTING-7-OWC	27	30	29	0.9
U-COM-EXISTING-8-OWC	30	Above 30	87	13.5
C-COM-EXISTING-1-IDA	-100	8	1	0.2
U-COM-EXISTING-2-IDA	8	15	12	0.1
U-COM-EXISTING-3-IDA	15	20	17	0.1
U-COM-EXISTING-4-IDA	20	22	0	0.0
U-COM-EXISTING-5-IDA	22	25	24	0.0
U-COM-EXISTING-6-IDA	25	27	24	0.0
U-COM-EXISTING-7-IDA	27	30	29	0.0
U-COM-EXISTING-8-IDA	30	Above 30	87	0.1
C-COM-EXISTING-1-WY	-100	8	1	1.5
U-COM-EXISTING-2-WY	8	15	11	0.8
U-COM-EXISTING-3-WY	15	20	17	0.4
U-COM-EXISTING-4-WY	20	22	0	0.0
U-COM-EXISTING-5-WY	22	25	24	0.2
U-COM-EXISTING-6-WY	25	27	0	0.0
U-COM-EXISTING-7-WY	27	30	28	0.0
U-COM-EXISTING-8-WY	30	Above 30	78	1.3
C-COM-EXISTING-1-UT	-100	8	2	46.3
U-COM-EXISTING-2-UT	8	15	12	17.3
U-COM-EXISTING-3-UT	15	20	18	19.5
U-COM-EXISTING-4-UT	20	22	22	0.2
U-COM-EXISTING-5-UT	22	25	25	4.0
U-COM-EXISTING-6-UT	25	27	27	0.8
U-COM-EXISTING-7-UT	27	30	30	1.3
U-COM-EXISTING-8-UT	30	Above 30	83	30.4
C-COM-NEW-1-OWC	-100	8	2	19.3
U-COM-NEW-2-OWC	8	15	11	16.9
U-COM-NEW-3-OWC	15	20	18	3.5
U-COM-NEW-4-OWC	20	22	22	2.0
U-COM-NEW-5-OWC	22	25	24	2.6
U-COM-NEW-6-OWC	25	27	26	0.3
U-COM-NEW-7-OWC	27	30	29	1.4
U-COM-NEW-8-OWC	30	Above 30	61	44.2
C-COM-NEW-1-IDA	-100	8	2	1.6
U-COM-NEW-2-IDA	8	15	11	0.9
U-COM-NEW-3-IDA	15	20	17	0.3
U-COM-NEW-4-IDA	20	22	20	0.0
U-COM-NEW-5-IDA	22	25	23	0.0
U-COM-NEW-6-IDA	25	27	25	0.0
U-COM-NEW-7-IDA	27	30	28	0.0
U-COM-NEW-8-IDA	30	Above 30	50	2.1
C-COM-NEW-1-WY	-100	8	1	6.1
U-COM-NEW-2-WY	8	15	12	3.2
U-COM-NEW-3-WY	15	20	17	1.7
U-COM-NEW-4-WY	20	22	21	0.0
U-COM-NEW-5-WY	22	25	23	0.3
U-COM-NEW-6-WY	25	27	25	0.0
U-COM-NEW-7-WY	27	30	27	0.1
U-COM-NEW-8-WY	30	Above 30	48	9.6
C-COM-NEW-1-UT	-100	8	3	16.0
U-COM-NEW-2-UT	8	15	12	9.5

DSM Total Costs and Savings Potential By Resource Bundle

Table 7, Page 2 of 3

Program Descriptor	Resource Bundle Lower Limit	Resource Bundle Upper Limit	Levelized 50 Year TRC (MILLS/KWH) *	1997-2017 Savings MWA
U-COM-NEW-3-UT	15	20	17	4.5
U-COM-NEW-4-UT	20	22	21	0.1
U-COM-NEW-5-UT	22	25	24	0.9
U-COM-NEW-6-UT	25	27	27	0.3
U-COM-NEW-7-UT	27	30	30	0.2
U-COM-NEW-8-UT	30	Above 30	55	29.7
U-IND-EXISTING-1-OWC	0	5	5	20.6
U-IND-EXISTING-2-OWC	5	10	11	7.2
U-IND-EXISTING-3-OWC	10	15	15	3.9
U-IND-EXISTING-4-OWC	15	17	19	9.3
U-IND-EXISTING-5-OWC	17	22	24	7.1
U-IND-EXISTING-6-OWC	22	27	30	6.4
U-IND-EXISTING-7-OWC	27	32	35	5.4
U-IND-EXISTING-8-OWC	32	Above 32	42	3.9
U-IND-EXISTING-1-IDA	0	5	5	4.1
U-IND-EXISTING-2-IDA	5	10	11	1.4
U-IND-EXISTING-3-IDA	10	15	16	0.8
U-IND-EXISTING-4-IDA	15	17	20	1.9
U-IND-EXISTING-5-IDA	17	22	25	1.4
U-IND-EXISTING-6-IDA	22	27	32	1.3
U-IND-EXISTING-7-IDA	27	32	37	1.1
U-IND-EXISTING-8-IDA	32	Above 32	44	0.8
U-IND-EXISTING-1-WY	0	5	5	21.9
U-IND-EXISTING-2-WY	5	10	11	7.7
U-IND-EXISTING-3-WY	10	15	15	4.1
U-IND-EXISTING-4-WY	15	17	19	9.9
U-IND-EXISTING-5-WY	17	22	25	7.5
U-IND-EXISTING-6-WY	22	27	31	6.8
U-IND-EXISTING-7-WY	27	32	36	5.7
U-IND-EXISTING-8-WY	32	Above 32	43	4.2
U-IND-EXISTING-1-UT	0	5	5	32.7
U-IND-EXISTING-2-UT	5	10	12	11.4
U-IND-EXISTING-3-UT	10	15	16	6.2
U-IND-EXISTING-4-UT	15	17	20	14.7
U-IND-EXISTING-5-UT	17	22	26	11.2
U-IND-EXISTING-6-UT	22	27	32	10.1
U-IND-EXISTING-7-UT	27	32	37	8.6
U-IND-EXISTING-8-UT	32	Above 32	44	6.2
U-IRR-EXISTING-1-OWC			25	2.3
U-IRR-EXISTING-1-IDA			33	2.3
U-IRR-EXISTING-1-WY			25	0.0
U-IRR-EXISTING-1-UT			25	0.7

* including replacement cost and program admin costs and bulk-up

DSM Total Costs and Savings Potential By Resource Bundle

Table 7, Page 3 of 3

Program Descriptor	Resource Bundle Lower Limit	Resource Bundle Upper Limit	Levelized 50 Year TRC (MILLS/KWH) *	1997-2017 Savings MWA
SGCENTS-OWC	Various Measures		17	5.2
SGCENTS-UT	Various Measures		17	0.8
SGCENTS-WY	Various Measures		17	4.0
SGCENTS-IDA	Various Measures		17	0.2
AP.RTRO-B1-OWC	Water Saving Measures		0	2.9
AP.RTRO-B1-UT	Water Saving Measures		0	1.9
AP.RTRO-B1-WY	Water Saving Measures		0	0.5
AP.RTRO-B1-IDA	Water Saving Measures		0	0.2
AP.RTRO-B2-OWC	Lighting Measures		16	6.9
AP.RTRO-B2-UT	Lighting Measures		16	7.1
AP.RTRO-B2-WY	Lighting Measures		16	1.2
AP.RTRO-B2-IDA	Lighting Measures		16	0.6
AP.New-B1-OWC	Water saving and Lighting measures		0	13.8
AP.New-B1-UT	Water saving and Lighting measures		0	9.3
AP.New-B1-WY	Water saving and Lighting measures		0	2.6
AP.New-B1-IDA	Water saving and Lighting measures		0	0.9
AP.New-B2-OWC	Super Eff. Refrigerator Program		5	1.3
AP.New-B2-UT	Super Eff. Refrigerator Program		5	1.5
AP.New-B2-WY	Super Eff. Refrigerator Program		5	0.2
AP.New-B2-IDA	Super Eff. Refrigerator Program		5	0.1
AP.New-B3-OWC	Horizontal Axis Washing Machines		0	0.1
AP.New-B3-UT	Horizontal Axis Washing Machines		0	0.8
AP.New-B3-WY	Horizontal Axis Washing Machines		0	0.9
AP.New-B3-IDA	Horizontal Axis Washing Machines		0	0.1

company updated savings and costs for the industrial sector using data from the Industrial FinAnswer program.

The company used Oregon's UM-551 as a screening guideline for commercial and industrial bundles. For each measure the company calculated total resource costs including incremental measure cost, measure design and modeling assistance, commissioning and quality control, program administration, taxes and interest charges. Each measure's savings to calculate TRC included the dollar value of savings in electricity, gas, and water usage, and labor savings.

Market Prices

For this Update the company reviewed recent market prices and expected patterns of escalation over the study period. For RAMPP-4 the company used 19 mills/kWh for on-peak non-firm power, and 16 mills/kWh for off-peak non-firm power for all regions and all seasons. As the market has changed, terminology has changed. On-peak and off-peak are now high-load and low-load hours, respectively. Non-firm is now short-term, and firm is now long-term.

Table 8 shows prices for short-term market power by region, season, and year, as well as the real escalation rate. PacifiCorp expects market prices will remain fairly constant over the next few years, but will then rise rapidly to the fully allocated cost of a new combined cycle combustion turbine (approximately $25/MWh in $1997) around 2003 when the region will be in load/resource balance. Graph 9 shows this "lazy s" curve. As equilibrium approaches, there will be a premium on capacity. For this reason the price for power in high-load hours will escalate more rapidly than the price for power in low-load hours. Table 1 above shows the change in average prices for short-term market power between RAMPP-4 and the Update.

The Update also re-specified the amount of power available in the wholesale market for new short-term purchases and sales (formerly referred to as non-firm purchases and sales in RAMPP-4). The model now assumes that there is a certain amount of energy available at one price and more energy available at a price two mills higher. In the OWC and DSW areas the model can make up to 350 MW of market purchases; in the OWC, CAL, and DSW areas the model can make up to 700 MW of market sales. These are the only areas where the model can make purchases or sales of short-term power. The model can also make 100 MW more in short-term purchases in each area at an incremental price 2 mills higher, and can make 200 MW more in

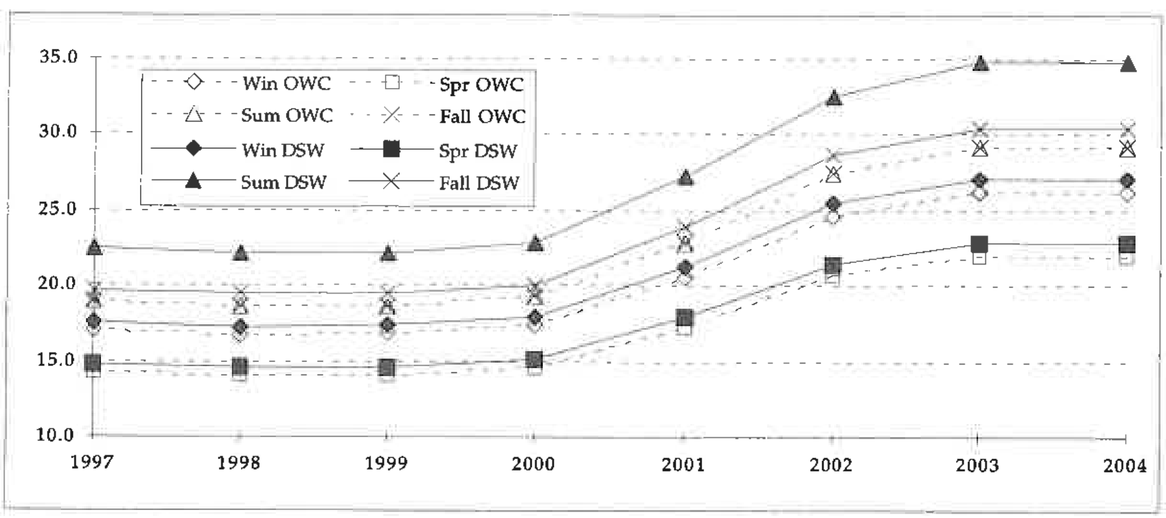
Wholesale Market Prices and Escalation
$1997 Mills/kWh

Table 8

	OWC Win	OWC Spr	OWC Sum	OWC Fall	DSW Win	DSW Spr	DSW Sum	DSW Fall	Average Annual	Real Escalation
	High Load Hours (57% of hours)									%
1997	17.0	14.3	18.9	18.9	17.6	14.8	22.5	19.8	18.0	
1998	16.7	14.0	18.6	18.6	17.3	14.6	22.2	19.4	17.7	-1.5%
1999	16.8	14.1	18.7	18.7	17.3	14.6	22.2	19.5	17.7	0.3%
2000	17.3	14.5	19.3	19.3	17.9	15.1	22.9	20.1	18.3	3.1%
2001	20.6	17.2	22.9	22.9	21.2	17.9	27.2	23.9	21.7	18.6%
2002	24.6	20.7	27.4	27.4	25.4	21.4	32.6	28.6	26.0	19.8%
2003	26.3	22.0	29.2	29.2	27.1	22.9	34.8	30.5	27.8	6.7%
2004	26.3	22.0	29.2	29.2	27.1	22.9	34.8	30.5	27.8	0.0%
	Low Load Hours (43% of hours)									%
1997	10.4	7.5	11.6	14.1	8.5	7.8	11.8	9.5	10.2	
1998	10.2	7.3	11.3	13.7	8.2	7.6	11.5	9.3	9.9	-2.6%
1999	9.9	7.1	11.0	13.4	8.0	7.4	11.2	9.0	9.6	-2.6%
2000	9.8	7.1	10.9	13.3	8.0	7.3	11.1	9.0	9.6	-0.6%
2001	9.8	7.0	10.9	13.2	8.0	7.3	11.1	8.9	9.5	-0.3%
2002	9.8	7.0	10.9	13.2	7.9	7.3	11.1	8.9	9.5	-0.2%
2003	9.8	7.0	10.9	13.2	7.9	7.3	11.1	8.9	9.5	-0.2%
2004	9.6	6.9	10.7	13.0	7.8	7.2	10.9	8.8	9.4	-1.4%

Wholesale Market Prices: High-Load Hours

Graph 9



OWC = Western part of the system
DSW = Eastern part of the system

lih R4u - Report Tables .xls Table 8.Graph 9 12/10/1996 11:05 AM short-term sales in each area at an incremental price 2 mills lower. This is an attempt to develop supply curves in the wholesale market.

Gas Prices

The modeling of gas prices for this Update included two steps. The first is an estimate of the beginning gas price. The second is an estimate of price escalation rates for the study period.

The company calculated actual wellhead prices for 1997 from both border and plantgate prices. The source for border prices for Sumas ($1.28) and Kingsgate ($1.29) for 1997 was a market solicitation on September 4. The company combined these prices with a Questar plantgate price of $1.38. Adjustments for gathering and processing, in addition to Canadian transport, were then made to plantgate and border prices respectively to derive initial wellhead prices of $1.28 for the west side and $1.38 for the east side.

A hybrid approach estimated escalation rates for two time periods. For the first time period of 1997 through 2006, the company used the concept of full cost recovery. For the second time period of the years after 2006, the company used updated escalation rates. The year 2006 is the dividing line between the two time periods because it is when most gas forecasters expect depletion of existing proven western reserves.

Recently there has been a dramatic shift in gas prices among the major producing regions. The disparity in prices between Henry Hub (for the eastern United States) and Western Region Production (the basis differential) has increased almost threefold over the last six months. The Western Region Production index consists of prices at Sumas, British Columbia; Kingsgate, Alberta; and an average for the Rockies. This change in relative prices is due to several factors. First, expectations produced by stronger prices during 1992 and 1993 produced a dramatic increase in supply, particularly in Alberta. While Rocky Mountain and British Columbia exploration and production may have slackened the last year, production continues to be very strong in Alberta. Alberta producers have continued to set record production levels over the last year despite low revenues. Second, the lack of sufficient transportation capacity from these western production areas to Eastern Canada and to the Midwest has effectively constrained the flow of gas from the Rockies, creating an over-supply in the western region. Finally, while the Western United States experienced a mild winter of 1995-96, the Eastern United States

Natural Gas Price Projections
Full Cycle Replacement Costs

Table 10

1997$/MMBTU

BRITISH COLUMBIA	LOW	MED	HIGH
EXPLORATION DRILLING	0.153	0.204	0.255
DEVELOPMENT DRILLING/FACILITIES	0.306	0.357	0.408
LEASE OPERATING EXPENSE	0.102	0.153	0.204
ROYALTY	0.080	0.102	0.124
TAXES	0.071	0.112	0.153
FINANCING	0.125	0.153	0.181
TOTAL WELLHEAD COSTS	0.838	1.081	1.325

ALBERTA	LOW	MED	HIGH
EXPLORATION DRILLING	0.153	0.204	0.255
DEVELOPMENT DRILLING/FACILITIES	0.306	0.357	0.408
LEASE OPERATING EXPENSE	0.102	0.153	0.204
ROYALTY	0.080	0.102	0.124
TAXES	0.071	0.112	0.153
FINANCING	0.125	0.153	0.181
TOTAL WELLHEAD COSTS	0.838	1.081	1.325

ROCKIES	LOW	MED	HIGH
EXPLORATION DRILLING	0.187	0.258	0.328
DEVELOPMENT DRILLING/FACILITIES	0.468	0.562	0.655
LEASE OPERATING EXPENSE	0.140	0.187	0.234
ROYALTY	0.114	0.144	0.174
TAXES	0.066	0.103	0.150
FINANCING	0.179	0.223	0.268
TOTAL WELLHEAD COSTS	1.154	1.477	1.809

2006$/MMBTU

BRITISH COLUMBIA	LOW	MED	HIGH
EXPLORATION DRILLING	0.200	0.266	0.333
DEVELOPMENT DRILLING/FACILITIES	0.399	0.466	0.532
LEASE OPERATING EXPENSE	0.133	0.200	0.266
ROYALTY	0.105	0.133	0.162
TAXES	0.093	0.146	0.200
FINANCING	0.163	0.200	0.236
TOTAL WELLHEAD COSTS	1.093	1.411	1.729

ALBERTA	LOW	MED	HIGH
EXPLORATION DRILLING	0.200	0.266	0.333
DEVELOPMENT DRILLING/FACILITIES	0.399	0.466	0.532
LEASE OPERATING EXPENSE	0.133	0.200	0.266
ROYALTY	0.105	0.133	0.162
TAXES	0.093	0.146	0.200
FINANCING	0.163	0.200	0.236
TOTAL WELLHEAD COSTS	1.093	1.411	1.729

ROCKIES	LOW	MED	HIGH
EXPLORATION DRILLING	0.244	0.336	0.428
DEVELOPMENT DRILLING/FACILITIES	0.611	0.733	0.855
LEASE OPERATING EXPENSE	0.183	0.244	0.305
ROYALTY	0.148	0.188	0.227
TAXES	0.086	0.134	0.196
FINANCING	0.233	0.292	0.350
TOTAL WELLHEAD COSTS	1.506	1.927	2.361

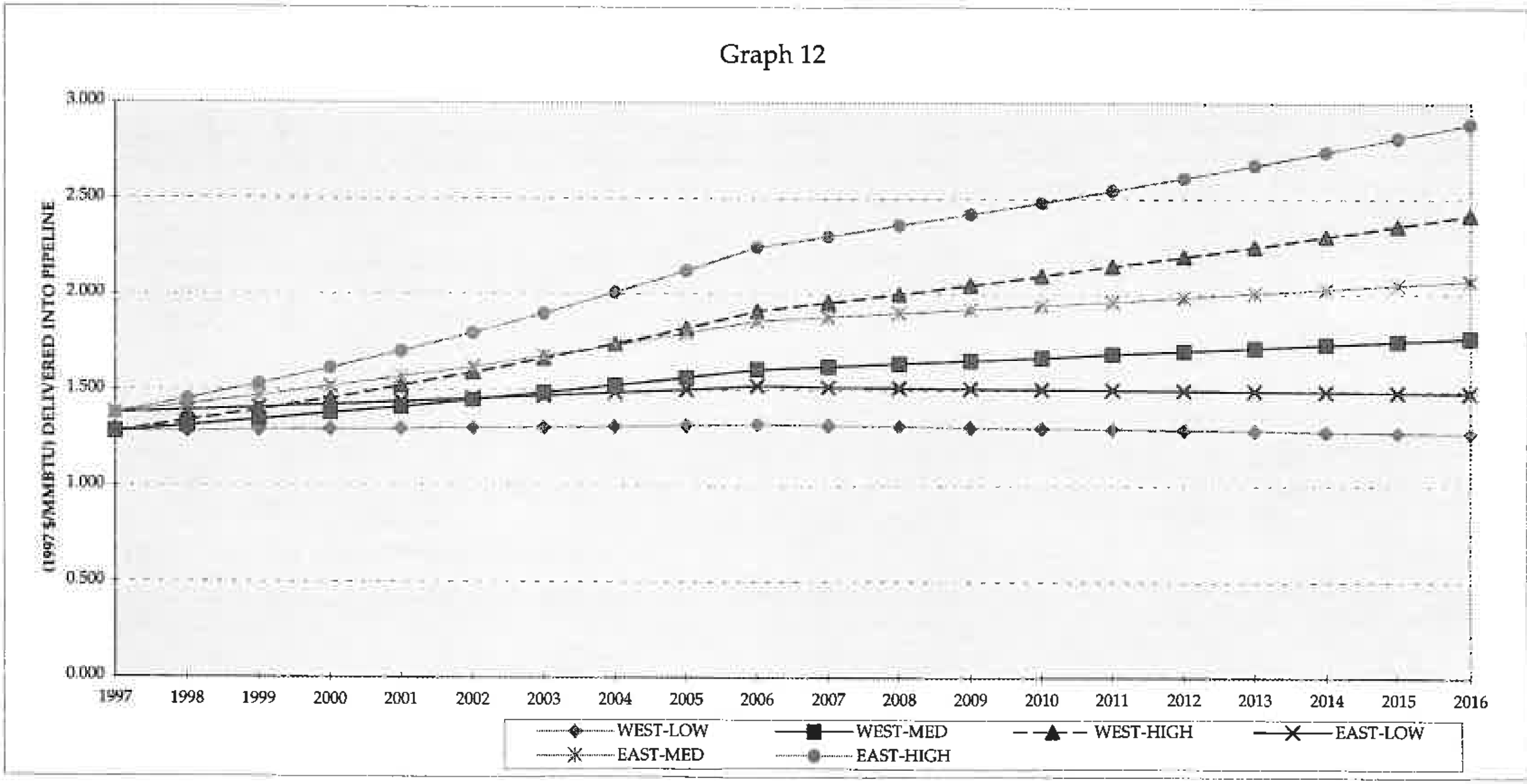
SOURCE:
BARAKAT & CHAMBERLIN, INC.

Natural Gas Price Projections
Comparison of Various Industry Estimates Post 2006

Table 11

LOW GROWTH RATE AVG			0.0%
GRI	GRI BASELINE PROJECTION	JANUARY 1996	-0.1%
AGA	AMERICAN GAS ASSOCIATION "THE GAS ENERGY SUPPLY & DEMAND OUTLOOK 1996-2015"	JULY 1996	0.0%
MEDIUM GROWTH RATE AVG			**1.5%**
EIA- LOW	DEPARTMENT OF ENERGY/EIA ANNUAL ENERGY OUTLOOK	JANUARY 1996	1.6%
NPPC - LOW	NORTHWEST POWER PLANNING COUNCIL 1996 DRAFT POWER PLAN	SPRING 1996	0.7%
NPPC - ML	NORTHWEST POWER PLANNING COUNCIL 1996 DRAFT POWER PLAN	SPRING 1996	1.5%
NPPC - MED	NORTHWEST POWER PLANNING COUNCIL 1996 DRAFT POWER PLAN	SPRING 1996	1.7%
WEFA - LOWER 48	WEFA	FALL-WINTER 1995-1996	1.9%
HIGH GROWTH RATE AVG			**3.0%**
EIA - BASE	DEPARTMENT OF ENERGY/EIA ANNUAL ENERGY OUTLOOK	JANUARY 1996	2.6%
EIA - HIGH	DEPARTMENT OF ENERGY/EIA ANNUAL ENERGY OUTLOOK	JANUARY 1996	4.9%
DRI	DRI: WORLD ENERGY SERVICE U.S. OUTLOOK SUPPLEMENT	FALL-WINTER 1995-1996	2.4%
NPPC - MH	NORTHWEST POWER PLANNING COUNCIL 1996 DRAFT POWER PLAN	SPRING 1996	2.2%
NPPC - HIGH	NORTHWEST POWER PLANNING COUNCIL 1996 DRAFT POWER PLAN	SPRING 1996	2.7%
WEFA-ALBERTA	WEFA	FALL-WINTER 1995-1996	2.8%
WEFA-BC	WEFA	FALL-WINTER 1995-1996	3.3%
CERI	CANADIAN ENERGY RESEARCH INSTITUTE (CERI) NORTH AMERICAN NATURAL GAS OUTLOOK BASIN-ON-BASIN COMPETITION	MAY 1996	3.1%
DOBSON (BC & ALBERTA)	DOBSON RESOURCE MANAGEMENT SURVEY OF HYDROCARBON PRICE FORECASTS UTILIZED BY CANADIAN PETROLEUM CONSULTANTS AND CANADIAN BANKS	JANUARY 1996	2.1%

Natural Gas Price Projections (Real $)



Natural Gas Price Projections
Westside and Eastside (1997$/MMBTU)

Table 13

LOW GAS ESCALATION RATES

	WESTSIDE	EASTSIDE
1997	1.283	1.380
1998	1.287	1.394
1999	1.291	1.409
2000	1.295	1.423
2001	1.299	1.439
2002	1.303	1.454
2003	1.307	1.470
2004	1.312	1.487
2005	1.317	1.503
2006	1.322	1.521
2007	1.317	1.517
2008	1.313	1.514
2009	1.308	1.510
2010	1.304	1.507
2011	1.300	1.503
2012	1.295	1.500
2013	1.291	1.496
2014	1.287	1.493
2015	1.283	1.490
2016	1.278	1.487

MEDIUM GAS ESCALATION RATES

	WESTSIDE	EASTSIDE
1997	1.283	1.380
1998	1.314	1.424
1999	1.345	1.470
2000	1.379	1.518
2001	1.413	1.568
2002	1.449	1.621
2003	1.486	1.677
2004	1.525	1.735
2005	1.566	1.796
2006	1.608	1.860
2007	1.624	1.880
2008	1.640	1.900
2009	1.656	1.920
2010	1.672	1.941
2011	1.688	1.962
2012	1.705	1.983
2013	1.722	2.005
2014	1.739	2.027
2015	1.757	2.050
2016	1.775	2.073

HIGH GAS ESCALATION RATES

	WESTSIDE	EASTSIDE
1997	1.283	1.380
1998	1.338	1.453
1999	1.395	1.531
2000	1.457	1.614
2001	1.522	1.703
2002	1.590	1.798
2003	1.663	1.899
2004	1.741	2.007
2005	1.823	2.122
2006	1.909	2.246
2007	1.954	2.303
2008	2.000	2.361
2009	2.048	2.421
2010	2.096	2.483
2011	2.146	2.547
2012	2.197	2.612
2013	2.250	2.679
2014	2.304	2.748
2015	2.359	2.819
2016	2.416	2.892

(1997 $/MMBTU) DELIVERED INTO PIPELINE

and the Midwest experienced a very severe and prolonged winter season, increasing eastern demand for gas.

The company expects the basis differential to decrease over time. With the differential between Henry Hub and Alberta currently averaging $1.77 for 1996, many producers located in the San Juan, Rockies, and Western Canadian producing regions are seeking new customers and markets, which should ease the current over-supply. Likewise, pipeline companies have strong financial incentives to build expansions of pipelines to regions where prices are higher.

Proposed pipeline expansion projects include the Pony Express project from Wyoming to Kansas City; the TransColorado project from Piceance, Colorado to New Mexico and Texas; the Zephr project from Rawlins, Wyoming to Hesston, Kansas; the WIC Expansion project from Kanda, Wyoming to Nebraska; the Northern Border project from Alberta to Chicago; and the Alliance project from Alberta to Chicago.

These efforts should result in a narrowing of the basis differential between Henry Hub and western prices. The company believes that producers will need gas prices that reflect full replacement costs of reserves by the end of 2006. With current depressed cash prices, producers are unable to invest in exploration activities. As the reserves-to-production ratio drops (a change in the supply curve), gas prices will trend towards full-cycle replacement costs.

The company obtained full-cycle replacement cost estimates from the firm of Barakat and Chamberlin, Inc. Their extensive market research suggested that a quantifiable range of wellhead costs exists. During the initial ten year period, the escalation rate represents the annual percentage increase necessary to move from current depressed prices to full-cycle replacement costs in 2006. Table 10 shows the components for full cycle replacement costs in British Columbia, Alberta, and the Rockies in both 1997$ and 2006$. The full cycle replacement cost for British Columbia production in the medium case is $1.081/MMBtu ($1997) or $1.411 (nominal) in 2006 (based on a general inflation rate of 3 percent). A nominal escalation rate of 7.15 percent would be required in order for the current wellhead price of $.758/MMBtu to equal the full replacement cost of $1.411 (nominal) in 2006.

For gas price escalation after 2006, the company used studies performed by several organizations: Gas Research Institute, Energy Information Administration, American Gas Association, Data Resources Inc. (DRI), and several Canadian publications. Significant improvements in seismic technology, improved production rates and fracturing technologies have resulted in lower well drilling and production costs, producing lower long-term escalation rates for gas prices.

A grouping of the studies into low, medium, and high resulted in a low growth rate of 0.0 percent real, a medium growth rate of 1.5 percent real, and a high growth rate of 3.0 percent real. Table 11 shows the derivation of these three growth rates from a grouping of nine studies. Graph 12 shows the low, medium, and high price projections in real dollars for the entire study 20-year period for both the western and eastern parts of the system.

Table 13 shows the results of the company's updating of gas prices with year-by-year prices for the west and east sides of the system, for all three gas price levels of low, medium, and high.

Table 14 shows these numbers compared to the RAMPP-4 inputs.

Table 14
Natural Gas Price Projections: RAMPP-4 versus RAMPP-4 Update

	Medium Escalation In $/MMBtu	
	West Side	East Side
Beginning Price		
RAMPP-4	1.55	1.55
RAMPP-4 Update	1.28	1.38

Transmission Costs

The company adjusted transmission costs for inflation. The portfolio of costs for new supply-side resource includes the cost to connect the new resource to the backbone transmission grid. There is no reason to believe that the costs used in RAMPP-4 have increased or decreased since RAMPP-4, other than for one year of inflation.

Supply-Side Resources

The biggest change in supply-side resources is a significant decline in capital costs. Most of the cost reduction is due to increasing competition among vendors of power plant equipment and decreased redundancy in design. Since RAMPP-4, costs for natural gas-based power plants declined approximately 15 percent and costs for coal-based power plants declined about 25 percent. Competitive pressures in the electric utility industry will continue to influence costs for a number of years.

The company updated the portfolio of supply-side resources by first adjusting costs to 1997$ values using an escalation rate of 3 percent. In addition, the portfolio includes cost changes in certain technologies.

The portfolio for the Update includes a number of new options including:

- Microturbines and fuel cells designed for use in distributed generation applications. These systems are still in the demonstration and design phases.

- Pressurized fluidized bed combustion (PFBC) is an alternative to conventional coal firing. PFBC has been demonstrated in a limited size range.

- Solar thermal hybrid: the demonstration of this technology at Solar II has spurred consideration of a hybrid arrangement of solar thermal with a conventional combustion turbine to achieve a more competitive power plant. Heat from the solar portion of the plant preheats combustion air and fuel to improve the overall efficiency of burning natural gas. Future applications depend on demonstration work.

- Sterling engine technology has been in concept work for many years. These small systems, 25 kW for each solar disk, is most economical at high production levels. The Update portfolio includes a small production level of 100 machines a year.

- Photovoltaic (PV) costs in the Update are about $5/kW beginning in 2005. This cost is approximately one-half the cost of the recent installation at Dangling Rope Marina.

- Plantation biomass reflects recent interest in systems that can be carbon-dioxide neutral by growing trees and then burning them. The Update includes this technology because of the availability of high-quality Pacific Northwest sites. Application on a commercial basis is still a number of years in the future.

Potential Resources

Table 15, Page 1 of 2

Sorted by Total Resource Cost

Description	Unit Size MW			1st Year Avail	Forced Outage Rate	Maint. Outage Rate	Full Load Heat Rate		Emissions			Capital Cost	
	Unit Size	Max Annual	MWs Avail.				Incremental	Average	NOX	TSP	CO2	Unit Cost	Trans-mission
							BTU/kWh		lbs/MMBTU				
OWC Cogen 2	234	470	1,390	2001	3.3%	3.8%	6,200	6,800	0.016	0.003	118.0	$583	$46
OWC Cogen 1	25	160	215	2001	3.3%	3.8%	4,300	5,500	0.016	0.003	118.0	$1,088	$0
Idaho Cogen 2	198	230	230	2001	3.3%	3.8%	6,200	6,800	0.016	0.003	118.0	$685	$46
Utah Cogen 2	198	400	1,780	2001	3.3%	3.8%	6,200	6,800	0.016	0.003	118.0	$685	$46
OWC Combined Cycle	234	450	unlimited	2001	3.3%	3.8%	7,167	7,520	0.016	0.003	118.0	$516	$46
Idaho Cogen 1	30	30	30	2001	3.3%	3.8%	4,300	5,500	0.016	0.003	118.0	$1,279	$0
Utah Cogen 1	20	20	15	2001	3.3%	3.8%	4,300	5,500	0.016	0.003	118.0	$1,279	$0
Idaho Combined Cycle	198	450	unlimited	2001	3.3%	3.8%	7,167	7,520	0.016	0.003	118.0	$793	$77
Utah Combined Cycle	198	450	unlimited	2001	3.3%	3.8%	7,167	7,520	0.016	0.003	118.0	$610	$77
Wyo Combined Cycle	182	450	unlimited	2001	3.3%	3.8%	7,167	7,520	0.016	0.003	118.0	$663	$77
Wyo PC Wyodak 2	325	264	264	2003	4.0%	4.5%	9,559	11,900	0.100	0.015	206.0	$1,148	$525
Utah PC Hunter 4 $20/	400	400	400	2003	4.0%	4.5%	9,559	10,060	0.100	0.015	206.0	$1,148	$52
Wyo Coal $6.70/Ton	325	330	unlimited	2003	4.0%	4.5%	9,559	10,760	0.100	0.015	206.0	$1,343	$525
Utah IGCC Hunter 4	262	262	262	2003	5.0%	4.5%	7,980	8,400	0.100	0.015	206.0	$1,261	$52
Utah Coal $23.25/Ton	400	400	1,250	2003	4.0%	4.5%	9,559	10,060	0.100	0.015	206.0	$1,343	$134
Utah IGCC CT	262	262	unlimited	2003	5.0%	4.5%	7,980	8,400	0.100	0.015	206.0	$1,261	$134
Utah Coal $27.00/Ton	400	400	1,250	2003	4.0%	4.5%	9,559	10,060	0.100	0.015	206.0	$1,343	$134
Wyo IGCC Wyodak 2	262	210	210	2003	5.0%	4.5%	7,980	8,880	0.100	0.015	206.0	$1,761	$525
Wyo IGCC CT	262	262	unlimited	2003	5.0%	4.5%	7,980	8,880	0.100	0.015	206.0	$1,761	$525
OWC Geothermal	50	100	300	2000	1.5%	3.8%	10,000	10,000	0.000	0.000	0.0	$2,214	$77
Utah Geothermal	50	100	300	2000	1.5%	3.8%	10,000	10,000	0.000	0.000	0.0	$2,214	$77
Utah Wind	50	100	200	1999	5.0%	0.0%	0	0	0.000	0.000	0.0	$1,042	$77
Wyo Wind	50	100	200	1999	5.0%	0.0%	0	0	0.000	0.000	0.0	$1,042	$77
OWC Simple Cycle CT	159	370	unlimited	2001	1.5%	0.0%	10,556	11,080	0.090	0.003	118.0	$271	$46
Utah Simple Cycle CT	135	370	unlimited	2001	1.5%	0.0%	10,556	11,080	0.090	0.003	118.0	$516	$77
Wyo Simple Cycle CT	124	320	unlimited	2001	1.5%	0.0%	10,556	11,080	0.090	0.003	118.0	$594	$77
Utah Pumped Storage	200	200	200	2002	1.0%	0.0%	0	0	0.000	0.000	0.0	$809	$77
OWC Pump Storage	200	200	500	2002	1.0%	0.0%	0	0	0.000	0.000	0.0	$824	$77
Utah Solar	50	100	1,000	1998	0.0%	0.0%	0	0	0.000	0.000	0.0	$4,624	$0

ljh R4u - R4u - Report Tables .xls - Table 15 - 12/10/199611:24 AM

Potential Resources

Table 15, Page 2 of 2

Sorted by Total Resourc

		Capital Cost $/kW		Fixed /Cost		Convert to Mills		Energy Cost in 2003 (1997$)			Variable	Total
	Total	Payment	Annual Pmt	Total	Ttl Fixed	Conversion	Ttl Fixed	1st Year	Levelized		O&M	Resource
Description	Cap Cost	Factor	$/kW-Yr	O&M	$/kW-Yr	Utilization	Mills/kWh	¢/MMBTU		Mills/kWh	Mills/kWh	Cost
OWC Cogen 2	$629	8.55%	$53.77	$5.50	$59.27	85%	7.96	184.2	204.9	12.70	0.55	21.21
OWC Cogen 1	$1,088	8.55%	$93.05	$5.50	$98.55	85%	13.24	184.2	204.9	8.81	0.55	22.59
Idaho Cogen 2	$731	8.55%	$62.51	$5.50	$68.01	85%	9.13	189.7	217.7	13.50	0.55	23.18
Utah Cogen 2	$731	8.55%	$62.51	$5.50	$68.01	85%	9.13	189.7	217.7	13.50	0.55	23.18
OWC Combined Cycle	$562	8.55%	$48.08	$23.79	$71.87	85%	9.65	184.2	204.9	14.69	0.29	24.63
Idaho Cogen 1	$1,279	8.55%	$109.38	$5.50	$114.88	85%	15.43	189.7	217.7	9.36	0.55	25.34
Utah Cogen 1	$1,279	8.55%	$109.38	$5.50	$114.88	85%	15.43	189.7	217.7	9.36	0.55	25.34
Idaho Combined Cycle	$870	8.55%	$74.41	$10.99	$85.40	85%	11.47	189.7	217.7	15.61	0.29	27.37
Utah Combined Cycle	$687	8.55%	$58.74	$28.12	$86.86	85%	11.67	189.7	217.7	15.61	0.29	27.56
Wyo Combined Cycle	$741	8.55%	$63.33	$30.59	$93.92	85%	12.61	189.7	217.7	15.61	0.29	28.51
Wyo PC Wyodak 2	$1,673	7.86%	$131.52	$40.22	$171.74	85%	23.06	40.8	42.4	4.05	0.46	27.58
Utah PC Hunter 4 $20/'	$1,200	7.86%	$94.28	$40.22	$134.50	85%	18.06	93.6	103.2	9.87	0.46	28.39
Wyo Coal $6.70/Ton	$1,868	7.86%	$146.85	$40.22	$187.07	85%	25.12	42.1	43.7	4.18	0.46	29.76
Utah IGCC Hunter 4	$1,313	8.55%	$112.22	$39.11	$151.33	85%	20.32	93.6	103.2	8.24	2.20	30.76
Utah Coal $23.25/Ton	$1,477	7.86%	$116.08	$40.22	$156.30	85%	20.99	108.8	120.0	11.47	0.46	32.92
Utah IGCC CT	$1,395	8.55%	$119.26	$39.11	$158.37	85%	21.27	108.8	120.0	9.58	2.20	33.05
Utah Coal $27.00/Ton	$1,477	7.86%	$116.08	$40.22	$156.30	85%	20.99	126.4	139.4	13.32	0.46	34.77
Wyo IGCC Wyodak 2	$2,287	8.55%	$195.50	$39.11	$234.61	85%	31.51	40.8	42.4	3.38	2.20	37.09
Wyo IGCC CT	$2,287	8.55%	$195.50	$39.11	$234.61	85%	31.51	42.1	43.7	3.49	2.20	37.20
OWC Geothermal	$2,291	9.11%	$208.73	$18.39	$227.12	90%	28.81	107.3	107.3	10.73	2.06	41.60
Utah Geothermal	$2,291	9.11%	$208.73	$18.39	$227.12	90%	28.81	107.3	107.3	10.73	2.06	41.60
Utah Wind	$1,119	5.56%	$62.23	$68.47	$130.70	36%	42.03	0.0	0.0	0.00	0.00	42.03
Wyo Wind	$1,119	5.56%	$62.23	$68.47	$130.70	36%	42.03	0.0	0.0	0.00	0.00	42.03
OWC Simple Cycle CT	$317	8.81%	$27.96	$22.54	$50.50	15%	38.43	158.4	179.2	18.91	0.10	57.44
Utah Simple Cycle CT	$593	8.81%	$52.27	$30.20	$82.47	15%	62.76	171.0	199.1	21.01	0.10	83.87
Wyo Simple Cycle CT	$671	8.81%	$59.09	$30.20	$89.29	15%	67.96	171.0	199.1	21.01	0.10	89.07
Utah Pumped Storage	$886	7.64%	$67.68	$13.39	$81.07	30%	30.85	0.0	0.0	0.00	0.00	30.85
OWC Pump Storage	$901	7.64%	$68.86	$13.39	$82.25	30%	31.30	0.0	0.0	0.00	0.00	31.30
Utah Solar	$4,624	5.56%	$257.09	$19.33	$276.42	28%	112.20	0.0	0.0	0.00	3.39	115.59

2595

- Storage systems may become more important in a competitive market to help system reliability and to meet the needs of customers.

Fixed operation and maintenance (O&M) expenses for resources in the portfolio include the ongoing capital cost required to keep the proposed power plant operational and efficient. Based on present plant experience, this is a cost of $7.00/kW-year. The coal plant estimates in the portfolio include this added cost. Other generation systems also have a cost of $3.00/kW-year for similar ongoing costs.

Table 15 shows the portfolio of supply-side resources included in the modeling. It begins with non-cost characteristics: unit sizes (although the model selects only the exact amount needed to bring the system to a 10 percent reserve margin), first year available, outage rates, heat rates, and emissions. The table continues with full cost information, beginning with capital costs for the plant and transmission needed to connect it to the backbone transmission system. The table converts this to an annual payment amount using the payment factor, and adds fixed O&M to arrive at a total annual fixed cost. The table then converts the total annual fixed cost to a mills/kWh. The overall mills/kWh is never input into the model. The model calculates its own mills/kWh to make its resource addition selections based on how the system needs a particular resource in each year. The company uses this table, and the resulting total resource cost, as a reasonableness check against model output results.

As with RAMPP-4, the least-cost supply-side resource is gas-fired cogeneration, followed by gas-fired combined cycle combustion turbine (CCCT). Coal-fired resources cost about 10 mills/kWh more, and renewables are even more expensive. Therefore, when the model needs to add new resources, it adds the least-cost choice: gas-fired cogeneration plants.

Cost of Capital

The real cost of capital declined from RAMPP-4's 5.1 percent to 4.8 percent. Inflation came down from 3.3 percent to 3.0 percent. That translates to nominal rates of 8.57 percent for RAMPP-4 and 7.94 percent for this Update. These changes in the cost of capital caused the resource annualization rates to change as well.

Modeling Results

To evaluate the modeling results for this Update, the company focused on the first ten years. The company also focused on the first ten years with the RAMPP-4 analysis. This focus on the early years of the planning period is due to the changing nature of the electric utility industry and the rapid rate of change now occurring. Given the uncertain nature of the industry 10 to 20 years out, the company decided not to give much attention to model results in that time period. In evaluating the modeling for this Update, the company looked at two key results:

1) Decision year for new resource acquisitions; and

2) Cost-effective amount of DSM for 1997.

Tables 16, 17, and 18 show the results of the Update base case for summer capacity, winter capacity, and energy, respectively. The model added three categories of resources: short-term capacity purchases, DSM, and cogeneration. It added 13.3 MW of short-term capacity purchases in 2000, 64 MW in 2004, and larger amounts beginning in 2006. This enabled the model to meet its reserve margin requirement in a least-cost way.

The model added increasing amounts of DSM beginning in 1997, not because the system needed additional resources then, but because DSM requires a ramp-up period. In order to have an adequate amount of DSM in place in 2002 when the system actually needs it, ramp-up must begin in 1997. Therefore the model added 15.7 MWa of DSM in 1997, 15.6 MWa in 1998, and 16.2 MWa in 1998.

A smaller amount of DSM is cost effective now than in early 1995 when the company conducted base case modeling for the RAMPP-4 report. Modeling in RAMPP-4 identified 25 MWa of cost-effective DSM for 1997 instead of the new result of 15.7 MWa. It is impossible to identify the exact contribution of each change in input assumptions to a change in DSM, due to the nature of a linear programming model. However, the company believes the reduction in cost-effective DSM is due to several factors: lower reserve margin in the Update, lower market prices, lower gas prices, and lower capital costs for gas-fired resources.

Base Case

Incremental Summer Capacity (MW) of Resource Additions

Table 16

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.3				64.0		121.3	228.3	476.9	500.0
	DSM Programs	6.8	7.1	7.0	7.3	7.7	7.7	7.8	8.1	8.0	12.5	20.6	24.4	30.6
O	OWC Geothermal													
W	OWC Cogen 1													123.7
C	OWC Cogen 2						189.0	196.1	118.1		122.1	274.1	351.9	55.3
	OWC Combined Cycle													
	OWC Simple Cycle CT													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**196.7**	**203.9**	**126.2**	**8.0**	**134.6**	**294.7**	**376.3**	**209.6**
I	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.6	1.0	1.7	1.9	2.4
D	Idaho Cogen 1													
A	Idaho Cogen 2													
H	Idaho Combined Cycle													
O	**Total**	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**1.0**	**1.7**	**1.9**	**2.4**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	13.0	13.7	14.4	22.7	39.3	47.3	61.4
	Utah Wind													
U	Utah Geothermal													
T	Utah Solar													
A	Utah Cogen 1													
H	Utah Cogen 2													377.2
	Utah Combined Cycle													
	Utah Simple Cycle CT													
	Utah Coal													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**13.0**	**13.7**	**14.4**	**22.7**	**39.3**	**47.3**	**438.6**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	3.0	2.9	3.1	3.0	5.2	8.4	9.4	12.0
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo Coal													
	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**3.0**	**2.9**	**3.1**	**3.0**	**5.2**	**8.4**	**9.4**	**12.0**
T	DSM Programs	21.7	21.6	22.3	23.2	23.6	24.3	24.3	25.5	26.0	41.4	70.0	83.0	106.4
O	Short Term Cap Purch				13.3				64.0		121.3	228.3	476.9	500.0
T	Cogeneration						189.0	196.1	118.1		122.1	274.1	351.9	556.2
A	Combined Cycle CT													
L	All Others													
	Total	**21.7**	**21.6**	**22.3**	**36.5**	**23.6**	**213.3**	**220.4**	**207.6**	**26.0**	**284.8**	**572.4**	**911.8**	**1,162.6**
	Annual Summer Peak Capacity (MW)													
S	Native Load	7,313	7,403	7,555	7,771	7,940	8,137	8,351	8,600	8,758	8,944	9,576	10,204	10,863
Y	Long Term Sales	2,582	2,648	2,369	2,295	1,933	1,808	1,778	1,578	1,370	1,362	1,112	987	942
S	DSM Programs	(22)	(43)	(66)	(89)	(112)	(137)	(161)	(186)	(213)	(254)	(324)	(407)	(513)
T	**Total Requirements**	**9,873**	**10,008**	**9,858**	**9,977**	**9,761**	**9,808**	**9,968**	**9,992**	**9,915**	**10,052**	**10,364**	**10,784**	**11,292**
E														
M	Existing Generation	9,949	9,994	10,010	9,842	9,848	9,855	9,855	9,766	9,770	9,653	9,665	9,527	9,527
	Long Term Purchases	1,147	1,191	1,121	1,120	1,100	823	808	658	658	658	608	608	587
L	Short Term Cap Purch				13				64		121	228	477	500
&	New Resources						189	385	503	503	626	900	1,251	1,808
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**10,867**	**11,048**	**10,991**	**10,931**	**11,058**	**11,401**	**11,863**	**12,422**
	Reserves	1,223	1,178	1,273	998	1,188	1,059	1,080	999	1,015	1,005	1,036	1,078	1,129
	Reserve Margin (RM) (%)	12.4	11.8	12.9	10.0	12.2	10.8	10.8	10.0	10.2	10.0	10.0	10.0	10.0

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Base Case
Incremental Winter Capacity (MW) of Resource Additions

Table 17

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.3				64.0		121.3	228.3	476.9	500.0
	DSM Programs	12.3	13.0	13.2	13.9	14.2	14.3	14.6	14.7	14.4	22.6	37.0	43.0	53.8
	OWC Geothermal													
O	OWC Cogen 1													131.6
W	OWC Cogen 2						201.1	208.6	125.7		129.8	291.6	374.3	58.9
C	OWC Combined Cycle													
	OWC Simple Cycle CT													
	Total	**12.3**	**13.0**	**13.2**	**13.9**	**14.2**	**215.4**	**223.2**	**140.4**	14.4	**152.4**	**328.6**	417.3	244.3
I	DSM Programs	0.5	0.5	0.4	0.5	0.5	0.5	0.6	0.5	0.5	0.9	1.5	1.7	2.1
D	Idaho Cogen 1													
A	Idaho Cogen 2													
H	Idaho Combined Cycle													
O	**Total**	**0.5**	**0.5**	**0.4**	**0.5**	**0.5**	**0.5**	**0.6**	**0.5**	**0.5**	**0.9**	**1.5**	**1.7**	**2.1**
	DSM Programs	11.4	10.9	11.9	12.7	12.2	13.0	12.9	13.6	14.3	22.8	39.6	47.4	61.9
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													401.3
H	Utah Combined Cycle													
	Utah Simple Cycle CT													
	Utah Coal													
	Total	**11.4**	**10.9**	**11.9**	**12.7**	**12.2**	**13.0**	**12.9**	**13.6**	**14.3**	**22.8**	**39.6**	**47.4**	**463.2**
	DSM Programs	2.9	3.0	2.9	3.1	3.1	3.1	3.2	3.1	3.2	5.4	8.7	9.8	12.4
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo Coal													
	Wyo Simple Cycle CT													
	Total	**2.9**	**3.0**	**2.9**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**	**3.2**	**5.4**	**8.7**	**9.8**	**12.4**
T	DSM Programs	27.1	27.4	28.4	30.2	30.0	30.9	31.3	31.9	32.4	51.7	86.8	101.9	130.2
O	Short Term Cap Purch				13.3				64.0		121.3	228.3	476.9	500.0
T	Cogeneration						201.1	208.6	125.7		129.8	291.6	374.3	591.8
A	Combined Cycle CT													
L	All Others													
	Total	**27.1**	**27.4**	**28.4**	**43.5**	**30.0**	**232.0**	**239.9**	**221.6**	**32.4**	**302.8**	**606.7**	**953.1**	**1,222.0**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,575	7,679	7,834	8,039	8,204	8,399	8,614	8,858	9,016	9,203	9,827	10,455	11,101
Y	Long Term Sales	2,369	2,560	2,134	2,000	1,735	1,294	1,283	1,083	875	867	667	492	462
S	DSM Programs	(27)	(55)	(83)	(113)	(143)	(174)	(205)	(237)	(270)	(321)	(408)	(510)	(640)
T	**Total Requirements**	**9,917**	**10,184**	**9,885**	**9,926**	**9,796**	**9,519**	**9,692**	**9,704**	**9,621**	**9,749**	**10,086**	**10,437**	**10,923**
E														
M	Existing Generation	9,969	10,016	10,054	9,881	9,887	9,894	9,898	9,805	9,805	9,683	9,695	9,550	9,550
	Long Term Purchases	1,287	1,391	1,557	1,744	1,723	1,437	1,435	998	998	998	948	948	927
L	Short Term Cap Purch				13				64		121	228	477	500
&	New Resources						201	410	535	535	666	957	1,331	1,923
R	**Total Resources**	**11,256**	**11,407**	**11,611**	**11,638**	**11,610**	**11,532**	**11,743**	**11,402**	**11,338**	**11,468**	**11,828**	**12,306**	**12,900**

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
Reserves	1,339	1,222	1,727	1,712	1,815	2,014	2,052	1,699	1,717	1,718	1,742	1,869	1,977
Reserve Margin (RM) (%)	13.5	12.0	17.5	17.2	18.5	21.2	21.2	17.5	17.8	17.6	17.3	17.9	18.1

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Base Case
Cumulative Annual Energy (MWa) of Resource Additions

Table 18

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.2	10.5	15.9	21.6	27.6	33.7	39.8	46.2	52.5	62.3	78.6	98.0	122.4
	OWC Geothermal													
O	OWC Cogen 1													122.5
W	OWC Cogen 2						183.9	344.8	450.6	450.6	532.2	765.4	1,064.9	1,112.0
C	OWC Combined Cycle													
	OWC Simple Cycle CT													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**217.6**	**384.7**	**496.8**	**503.1**	**594.5**	**844.0**	**1,162.9**	**1,356.9**
I	DSM Programs	0.5	0.9	1.3	1.8	2.2	2.7	3.1	3.6	4.1	4.9	6.2	7.8	9.7
D	Idaho Cogen 1													
A	Idaho Cogen 2													
H	Idaho Combined Cycle													
O	**Total**	**0.5**	**0.9**	**1.3**	**1.8**	**2.2**	**2.7**	**3.1**	**3.6**	**4.1**	**4.9**	**6.2**	**7.8**	**9.7**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	68.0	78.1	94.0	121.6	155.2	198.9
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													321.1
H	Utah Combined Cycle													
	Utah Simple Cycle CT													
	Utah Coal													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.0**	**78.1**	**94.0**	**121.6**	**155.2**	**519.9**
	DSM Programs	2.2	4.5	6.8	9.1	11.5	13.8	16.2	18.6	21.1	25.3	32.3	40.4	50.7
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo Coal													
	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.5**	**13.8**	**16.2**	**18.6**	**21.1**	**25.3**	**32.3**	**40.4**	**50.7**
T	DSM Programs	15.7	31.3	47.5	64.6	81.8	99.7	117.6	136.5	155.8	186.5	238.7	301.3	381.7
O	Short Term Cap Purch				0.0				0.1		0.1	0.2	0.5	0.5
T	Cogeneration						183.9	344.8	450.6	450.6	532.2	765.4	1,064.9	1,555.5
A	Combined Cycle CT													
L	Simple Cycle													
	All Others													
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**283.6**	**462.4**	**587.1**	**606.4**	**718.8**	**1,004.4**	**1,366.7**	**1,937.8**
S	Native Load	5,417	5,484	5,595	5,748	5,870	6,013	6,168	6,348	6,463	6,598	7,056	7,512	7,989
Y	Peak Return	309	309	307	259	259	259	259	259	257	257	257	257	257
S	Long Term Sales	2,394	2,272	2,006	1,794	1,560	1,426	1,395	1,284	1,124	1,086	922	815	771
T	Short Term Sales	882	984	1,103	1,156	1,198	1,248	1,298	1,277	1,345	1,291	1,299	1,213	1,228
E	DSM Programs	(16)	(31)	(48)	(65)	(82)	(100)	(118)	(136)	(156)	(187)	(239)	(301)	(382)
M	**Total Requirements**	8,987	9,018	8,963	8,892	8,804	8,846	9,001	9,031	9,032	9,045	9,295	9,495	9,863
	Existing Generation	7,774	7,714	7,662	7,605	7,742	7,808	7,822	7,762	7,761	7,689	7,705	7,601	7,519
L	Long Term Purchases	869	970	965	964	713	496	486	466	466	466	447	444	409
&	Short Term Purchases	343	334	337	323	349	358	349	352	354	358	377	385	380
R	New Resources	-	-	-	-	-	184	345	451	451	532	766	1,065	1,556
	Total Resources	8,987	9,018	8,963	8,892	8,804	8,846	9,001	9,031	9,032	9,045	9,295	9,495	9,863

ljh R4u - Report Tables .xls Table 16, Table 18 12/10/1996 11:44 AM

In RAMPP-4 the company used a reserve margin of 12 percent, but lowered it to 10 percent in the Update. That lowered the need for resource additions. In RAMPP-4 the company used an on-peak wholesale price of 19 mills/kWh and an off-peak price of 16 mills/kWh. This Update uses different prices by season and area. High-load hour prices for 1997 average 18 mills/kWh, for a decrease of 5 percent; low-load hour prices average 10.2 mills/kWh, for a decrease of 36 percent.

Natural gas prices decreased from 1.55/MMBtu in RAMPP-4 to 1.28/MMbtu and 1.38/MMbtu on the West and East sides, respectively, for an average decline of 14 percent.

Capital costs for gas-fired resources declined since RAMPP-4. The capital cost for OWC Cogen 2, the cheapest cogeneration unit in the Update, declined from $775/kW in RAMPP-4 to $629/kW in the Update, for a decline of 19 percent. The combined effect of gas prices and capital costs for gas-fired resources was a lowering of the TRC for cogeneration from 26.47 mills/kWh to 21.21 mills/kWh, or a decline of 20 percent. The following table shows the year-by-year decline in TRC for OWC Cogen 2.

TRC by Year for OWC Cogen 2
Table 19

	RAMPP-4	Update	% Difference
	Mills/kWh	Mills/kWh	
1997	23.77	18.72	-21
1998	23.98	18.89	-21
1999	24.20	19.09	-21
2000	24.42	19.29	-21
2001	24.65	19.49	-21
2002	24.88	19.70	-21

RAMPP-4 results confirm the impact of gas prices on DSM. One of the RAMPP-4 sensitivities lowered the escalation rate for gas prices from 2.11 percent real in the base case to 0 percent real. Under the lower gas price assumptions the model selected the following amounts of DSM in the first three years: 16.9 MWa, 18.8 MWa, and 19.4 MWa. Those amounts are close to the DSM selected for the first three years in the Update: 15.7 MWa, 15.6 MWa, and 16.2 MWa.

In 2002 the model began adding cogeneration, the least-cost supply-side choice. It added 189 MW in 2002, and similar amounts most years thereafter. The RAMPP-4 results showed that it would be cost effective to acquire a cogeneration unit beginning in 2003. This Update resulted in the deficit year moving forward by one year. This change in the deficit year is the result of several changes in the inputs. Table 20 shows the key inputs for the years 1997 and 2002.

Total System Inputs 1997 and 2002
Table 20

Summer MW	1997		2002	
	RAMPP-4	Update	RAMPP-4	Update
Native load	7,316	7,313	8,207	8,137
Firm sales	1,900	2,582	1,795	1,808
DSM	(68)	(22)	(297)	(137)
Total	9,148	9,873	9,705	9,808
Existing system	9,983	9,949	10,208	9,855
Firm purchases	758	1,147	662	823
Total	10,741	11,096	10,870	10,678
Reserve	1,593	1,223	1,165	870
Reserve %	17.4%	12.4%	12.0%	8.9%

The key inputs result in a system reserve of 1,593 MW in 1997 under RAMPP-4 but a reserve of only 1,223 under the Update assumptions. For 2002 the reserve went from 1,165 MW in RAMPP-4 to 870 MW in the Update. That 870 MW resulted in a reserve margin of only 8.9 percent. Since the reserve margin used in modeling for the Update required a reserve margin of 10 percent, a reserve of only 8.9 percent in 2002 triggered the model to add resources.

The modeling results confirm that the major conclusions from RAMPP-4 are still valid: gas-fired resources are the least-cost supply-side choice, the deficit year does not require a resource acquisition decision in the next two years, and modest amounts of DSM are still cost effective. Sensitivities planned for the spring of 1997 will explore the consistency of conclusions from the RAMPP-4 sensitivities. The company will continue to work with its public advisory group in developing and evaluating the sensitivities.

RAMPP-4 Action Plan Revisions

The single most significant principle in the RAMPP-4 action plan was the wisdom of postponing decisions. The company decided to find all cost-effective alternatives that would enable it to postpone and/or mitigate the need for capital expenditures to meet firm load requirements. The declining cost of power in the wholesale market during 1996 has confirmed the wisdom of postponing capital expenditures.

The modeling results indicate that it would be cost effective to acquire a cogeneration unit beginning in 2002. With a three-year lead time for cogeneration units (the company's last cogeneration unit, Hermiston, had a three-year lead time), that would require a decision in 1999. Between now and then, the company will continue to evaluate its resource needs, market opportunities, and resource acquisition opportunities.

The company believes the RAMPP-4 action plan is still valid, except for changes in the amount of DSM. Rather than continue with a 1997 target of 25 MWa based on RAMPP-4 modeling, the company is modifying its action plan to a new 1997 target of 15.7 MWa. The RAMPP-4 modeling, performed in the spring of 1995, used market and cost assumptions valid then, but no longer valid. The modeling conducted in the fall of 1996 indicates that using current market and cost assumptions, the cost-effective amount of DSM for 1997 is 15.7 MWa. The cost-effective amounts of DSM for 1998 and 1999 are 15.6 MWa and 16.2 MWa, respectively.

Commercial and industrial markets will be key targets for the company's 1997 DSM acquisitions. Table 21 shows the 1997 DSM targets in MWa by segment:

Table 21
DSM Targets by Segment for 1997

	At Generation Site	At Customer Site
Residential	1.8	1.6
Commercial	9.0	8.1
Industrial	4.8	4.3
Total	15.7	14.0

The amount shown in the "At Customer Site" column is less because of the reduction for line losses. DSM at a customer site can be 10 percent less than at the generation site because line losses do not occur with DSM. Residential DSM acquisition should come primarily from market transformation activities in lighting, refrigeration, and washing machine initiatives, as well as in low income weatherization and Super good Cents programs. Within the commercial segment, five of the nine MWa should come from new commercial construction and four should come from retrofit opportunities.

Performance on RAMPP-4 Action Plan

The following text reports the company's performance on the RAMPP-4 action plan during 1996.

1) DSM goal from RAMPP-4 Action Plan: Implement 23 MWa of installed cost-effective savings for 1996, 25 MWa for 1997, and 28 MWa for 1998. In addition pursue the following activities: a) identify and pursue opportunities to target DSM to areas that will allow the company to reduce its transmission and distribution costs; and b) pursue ways to increase participant contribution to DSM costs and develop alternative funding sources.

Performance: The company anticipates that it will achieve the 1996 goal of 23 MWa. As of September, 14.4 MWa were achieved, and known projects "in the pipeline" should easily make up the remaining 8.6 MWa. The company exceeded the residential goal of 2.2 MWa due to a very successful program in Oregon for multi-family (apartment) buildings.

a) Identify and pursue opportunities to target DSM to areas that will allow the company to reduce its transmission and distribution costs: during 1996 the company continued to gather data and explore opportunities to geographically target DSM to reduce transmission and distribution costs. The company developed criteria and incorporated them into standard operating procedures. Construction budget reports now routinely consider DSM, renewable technologies and possibly small scale generator strategies as potential alternatives to new transmission and distribution plant investments. Due to site-specific characteristics, targeted DSM is a viable tool but not the sole solution to every transmission and distribution bottleneck.

b) Pursue ways to increase participant contribution to DSM costs and develop alternative funding sources: the company continued to emphasize participant contributions through the Energy Service Charge in 1996: the company broadened its emphasis on maximizing participant contributions to maintain stable rates. Field representatives and account managers are alert to the possibilities of company-provided financing for DSM measures. The company found that about 65 percent of Energy FinAnswer participants self-funded or obtained non-company funding, compared to about 50 percent for 1995.

In addition to working with its own programs to maximize participant contributions to DSM, the company also worked at the regional and state levels to proactively develop alternative funding sources for "public purpose" DSM, including market transformation initiatives and low-income weatherization. The company actively participated in the Regional Comprehensive Review and sponsored discussions in the "Conservation in a Competitive World" forum, which sought to address an alternate funding mechanism for Oregon. PacifiCorp also participated in restructuring discussions in Idaho, Oregon, California, Utah, Montana, Washington, and Wyoming during 1996. Finally, the company has committed to initial funding for three years to support the recently formed Northwest Energy Efficiency Alliance, Inc. (NEEA), a nonprofit corporation to implement DSM market transformation initiatives. Funding for NEEA will come from a region-wide alternate funding mechanism, such as a meter charge, after an initial three-year period.

2) Peaking Resources goal from RAMPP-4 Action Plan: The RAMPP-4 action plan said the company should evaluate alternative ways to meet peaking needs and pursue opportunities that meet system needs cost-effectively. This included three sub-items: a) continue to evaluate opportunities for managing peaking needs and implement those that are cost-effective; b) use the market to find cost-effective opportunities to purchase summer peaking power; and c) evaluate opportunities to meet the company's peaking needs through peaking resources such as pumped storage, SCCTs, purchased power and existing peaking resources.

Performance: During 1996 the company purchased on the market any needed peaking resources. The market was the least-cost choice for peaking needs during that period of time.

3) Baseload Resources goal from RAMPP-4 Action Plan: The RAMPP-4 action plan identified a need to evaluate alternative ways to meet baseload needs and pursue opportunities that meet system needs cost-effectively. The company determined that it was unnecessary to make a decision to acquire new baseload resources during the three-year action plan period. However, PacifiCorp will pursue opportunities in all of the following three areas: a) work with customers to identify their needs and find environmentally responsible solutions, including cogeneration; b) continue to monitor the wholesale market for opportunities to purchase power at prices lower than other resource acquisitions; c) continue to evaluate cogeneration and CCCTs with independent developers and pursue agreements or options where cost effective. The company will acquire only those resources that benefit the system, either by providing power needed for retail loads, or power that can be profitably sold on the wholesale market.

Performance: During 1996 the company did not need to add baseload resources.

a) Work with customers to identify their needs and find environmentally responsible solutions, including cogeneration: the company had the opportunity to work with several customers to help make their systems more efficient. The following are several examples from 1996:

The University of Wyoming was having problems with their steam generation facility, which provides all heating for the campus. PacifiCorp sent a team of steam plant engineers to the University to train, evaluate and recommend efficiency improvements. The project resulted in a significant improvement in the steam plant's efficiency.

PacifiCorp contributed the initial funding for a membrane purification system study at the Boise Cascade plant at Wallula, WA. The system uses reverse osmosis to clear black liquor waste and bleach plant waste from their manufacturing processes. Additionally, when the project floundered due to delays in DOE funding, PacifiCorp's lobbyist was able to speed the funds though the approval cycle.

The James River plant at Camas, WA, operates a large turbine generator owned by PacifiCorp. Declining efficiency was causing problems for James River. PacifiCorp sent engineers and support people to the facility to provide training, evaluation and efficiency improvements for the James River plant.

PacifiCorp paid for two studies to develop alternatives to waste water treatment at the Pope & Talbot plant in Oregon. Pope & Talbot used the Willamette River to disperse the treated waste. However, the current system could not handle their plans to triple production. In conjunction with Oregon State University and PacifiCorp, Pope & Talbot changed to a series of 10 ponds and natural filtration methods to meet the increased production. This method uses rocks, plants, and other "green" systems to purify the water. This installation is the first in the world and has received positive national and international publicity.

PacifiCorp performed a study to evaluate power factor correction for the Monsanto plant at Soda Springs, Idaho. The company also evaluated system use and furnace operation methods to determine the best sizing for a new furnace.

b) Continue to monitor the wholesale market for opportunities to purchase power at prices lower than other resource acquisitions: the company continued to monitor the wholesale market for opportunities to purchase power at prices lower than other resource acquisitions.

c) Continue to evaluate cogeneration and CCCTs with independent developers and pursue agreements or options where cost effective: the company continued to evaluate cogeneration and CCCTs with independent developers. During 1996 the company did not determine that any agreements with independent developers were cost effective.

4) Existing System goal from RAMPP-4 Action Plan: The RAMPP-4 action plan identified a need to continue to make cost-effective improvements to the existing system. This included action in five areas: a) evaluating opportunities to enhance generation efficiency on the existing system and implement them when cost-effective; b) continuing with cost-effective turbine upgrades; c) bringing the Hermiston plant on-line by 1997; d) evaluating the cost-effectiveness of converting the Gadsby plant to a combined cycle unit and pursuing the conversion if it is cost-effective and if the system needs the generation; and e) continuing to implement cost-effective transmission and distribution system efficiencies.

Performance: The company continued making cost-effective improvements to the existing system. The following provides additional detail.

a) Evaluating opportunities to enhance generation efficiency on the existing system and implement them when cost-effective: PacifiCorp continues to evaluate opportunities to improve system efficiency through cost-effective additions to its existing operating units. For example, the FERC hydro relicense process requires re-evaluating each unit to assure that it is using the water resource to its maximum level. As a result of such an evaluation, the company's 1997 budget includes a project to replace the runner and overhaul the turbine on Prospect Unit 3. This modification will increase the unit capacity by 1 MW and increase the yearly energy production by an average of over 13,000 MWh. The company routinely studies similar projects are implements those that are cost-effective improvements.

Another project reviewed during 1996 identified potential capacity and energy increases from waste heat at the Blundell geothermal plant. This project was potentially attractive because of the possibility of using Clean Coal Technology funds from the DOE if a Kalina cycle were used. Doing so could add 14 MW of capacity to the existing facility. Unfortunately the economics of the project and industry uncertainty did not allow implementation.

The company routinely reviews and evaluates potential projects during the yearly budgeting process. The evolving competitive nature of the electric power industry is making the hurdle for efficiency projects more difficult. However, cost-effective projects, such as the steam turbine upgrades at the company's larger units, are being implemented.

b) Continuing with cost-effective turbine upgrades: the company will upgrade selected turbine units at coal plants to improve their performance. Some upgrades are on hold pending economic review. The economic review mainly applies to the smaller units in the PacifiCorp system. The Hunter 1 & 2 upgrades are pending environmental reviews to determine the allowable increase in capacity that is consistent with existing environmental regulations.

c) Bringing the Hermiston plant on-line by 1997: the Hermiston plant went on-line in July of 1996. It is now providing power for the company's customers.

d) Evaluating the cost-effectiveness of converting the Gadsby plant to a combined cycle unit and pursuing the conversion if it is cost-effective and if the system needs the generation: installing a natural gas fueled, combined-cycle from the infrastructure available at PacifiCorp's Gadsby station has been in review over the last few years. Currently the Gadsby Plant burns natural gas in conventional boilers for cycling and hot standby needs, and provides voltage support and other system benefits in the Salt Lake Valley. Because the existing heat rate is greater than 11,000 Btu's/kWh, the company runs Gadsby's three units infrequently. Repowering the site with new state-of-the-art combustion turbines and Heat Recovery Steam Generators (HRSG's) would improve the heat rates to nearly 7,000 Btu/kWh. Capital costs would be less than a new greenfield combined cycle because of the re-use of certain existing items such as makeup water, cooling towers, circulating water pipelines, and transmission facilities. During 1996 the company began additional evaluation work to determine the cost advantage of using the existing steam turbines in a new combined cycle power plant compared to using new steam turbine equipment at the Gadsby site. Implementation of an upgrade to the Gadsby Plant depends on the need for new capacity, the expected market value of electricity and the environmental acceptability of any proposed modifications. The company anticipates making a decision on upgrading the Gadsby Plant in the next few years. A decision will be necessary primarily because the environmental window to make substantial improvements at this inter-city site will close.

e) Continuing to implement cost-effective transmission and distribution system efficiencies: the company continues evaluating potential transmission and distribution system efficiencies to identify investment opportunities that would be cost-effective solutions to existing constraints.

5) Renewables goal from RAMPP-4 Action Plan: The RAMPP-4 action plan identified a need to pursue low-cost activities that increase the company's knowledge of renewable resources. This action item included several sub-sections: a) continue with plans to bring the Foote Creek, Wyoming, and Columbia Hills, Washington, wind projects on-line in 1996, and once these projects are operating, evaluate their performance and cost-effectiveness; b) continue to evaluate other potential wind projects and pursue agreements for cost-effective projects; c) continue to evaluate potential geothermal projects and pursue agreements for up to 25-50 MW of cost-effective projects; d) analyze geographic areas with constrained transmission and distribution capabilities and use cost-effective distributed generation to relieve constraints; e) continue to monitor global climate science; f) continue evaluating the cost-effectiveness of small-scale carbon offset projects; g) continue to participate in Solar II; h) continue to monitor the performance of the company's solar PV projects; i) continue participation in the Northwest Regional Solar Radiation Data Monitoring Project; and j) continue to support the OSU Wind Research Cooperative.

Performance: During 1996 the company was able to make progress on all of the above items.

a) Continue with plans to bring the Foote Creek, Wyoming, and Columbia Hills, Washington, wind projects on-line in 1996, and once these projects are operating, evaluate their performance and cost-effectiveness: Kenetech Windpower (KWI) filed for Chapter 11 bankruptcy in May, 1996. Development Agreements with both the Columbia Hills, Washington, and Wyoming Foote Creek wind projects reflected that KWI would develop the project. Since filing for bankruptcy KWI has been attempting to sell their assets to other wind developers.

KWI has been actively marketing the assets of the Wyoming wind project. A number of developers have submitted bids to KWI for their review. KWI is reviewing those bids and will make a recommendation to the bankruptcy court to accept one of the proposals. Following that recommendation, a due diligence period begins and ultimately a hearing will occur, at which time competitive bidding may take place. The bankruptcy process should be completed in late 1996 or early 1997.

PacifiCorp, Tri-State, and Eugene Water and Electric Board remain very interested in participating in the project. Public Service of Colorado has terminated their participation as an owner in the project, but remain interested in a power purchase option. Bonneville Power Administration continues their interest in purchasing some of the output. All of the parties are interested in working with a new developer that acquires the project's assets.

PacifiCorp discussed the project with a number of interested developers, some of whom may submit bids. Once a new developer is selected, the Bureau of Land Management (BLM) has indicated a willingness to closely work with the new developer to expeditiously issue their Record of Decision and Right of Way permit. There is a good likelihood the permitting issues can be resolved to PacifiCorp's satisfaction. However, environmental organizations may appeal the BLM permit.

The exact size of the project remains unclear at this time. Prior to PSCo's termination the project was 68.1 MW, but a reduction in their contribution could reduce the size to approximately 58 MW. The completion of the bankruptcy process and negotiation with a new developer will determine the size of the project, the individual levels of participation of each party, and other terms and conditions contained in the existing contracts.

The Columbia Hills wind project was to be jointly owned by Portland General Electric (PGE) and PacifiCorp. Although KWI had obtained the necessary permits for the project, they were not acceptable to the owners because of concerns about avian mortality issues. Therefore, both parties terminated their existing contracts, but are interested in discussing a power sales agreement with a new developer. KWI does not appear to be actively pursuing a sale of the assets of this project because there is little interest in a project that does not have a contract with any utilities. In addition to the concerns regarding avian issues, an appeal was pending at the time of the bankruptcy filing.

b) Continue to evaluate other potential wind projects and pursue agreements for cost-effective projects: the company continues to hold discussions with wind developers and to evaluate potential wind projects. In 1996 no proposed projects were cost effective compared to alternatives.

c) Continue to evaluate potential geothermal projects and pursue agreements for up to 25-50 MW of cost-effective projects: the company continues to hold discussions with developers and to evaluate potential geothermal projects. In 1996 no proposed projects were cost effective compared to alternatives.

d) Analyze geographic areas with constrained transmission and distribution capabilities and use cost-effective distributed generation to relieve constraints: although isolated parts of PacifiCorp's system have constrained transmission and distribution, the company is finding that the most cost-effective solutions tend to be related to equipment upgrades rather than distributed generation.

e) Continue to monitor global climate science: the Intergovernmental Panel on Climate Change (IPCC) released its Second Assessment Report in December of 1995. Company representatives appraised officers of these findings and the company continues to carefully track scientific developments on climate change. The Second Assessment Report refines earlier estimates for future average global temperatures. IPCC scientists are using increasingly sophisticated computer models to project future temperatures and they are becoming increasingly confident in their ability to distinguish "human influence" on the climate. Beside monitoring scientific findings, the company is increasingly active in the policy debate concerning international and domestic policy response to these findings.

f) Continue evaluating the cost-effectiveness of small-scale carbon offset projects: PacifiCorp is continuing in its efforts to test offset projects in accord with the company's Climate Challenge commitment to fund at least $1 million in offset projects through the year 2000. Project work included three projects: the Rio Bravo Project in Belize, UtiliTree, and methane recovery. PacifiCorp is in its second year of funding the 10-year Rio Bravo project. In 1996, the company purchased property for preservation and began stewardship projects on existing lands. The company contributes to UtiliTree, an Edison Electric Institute (EEI) program. UtiliTree Corporation selected five promising forestry projects including ones in Oregon and California. Advance work is complete to fund a promising CO2 offset project that will provide CO2 benefits by capturing methane at a coal mine. Project funding is likely for next year.

g) Continue to participate in Solar II: the opening ceremony for Solar II took place on June 5, 1996. During the year the facility showed significant power output and demonstrated the project's ability to generate electricity using energy stored in hot salt. The project has been able to resolve substantial difficulties during the year with "heat tracing" (e.g., keeping the salt from freezing in the lines and avoiding overheating). The project sponsors hope to be able to operate the plant for at least one year, but hopefully for two years. Future funding is not yet secure to reach this goal.

h) Continue to monitor the performance of the company's solar PV projects: this year the company and many other partners worked together to see diesel generation at the Dangling Rope Marina (on Utah's Lake Powell) replaced with a 115 kW PV system. The system, which is the second largest stand-alone PV system in the US, replaces diesel engines that consumed 65,000 gallons of fuel each year. PacifiCorp provided financial and technical assistance for the project. Along with the Utah Office of Energy, the company is now monitoring its performance. The company also has three smaller on-system PV sites up and running at the following locations: the High Desert Museum in Bend, Oregon; an elementary school in Green River, Wyoming; and a company office in Moab, Utah. By conducting around-the-clock monitoring at these sites PacifiCorp is learning about the capability of specific components as well as overall system cost-effectiveness.

i) Continue participation in the Northwest Solar Radiation Data Monitoring Project: PacifiCorp provided financial resources for the project, which is developing high quality data on solar sites around the Northwest. During the year, the project upgraded existing utility sites to provide data and, with the help of a grant from the National Renewable Energy Lab (NREL), is building several sophisticated data gathering sites.

j) Continue to support the OSU Wind Research Cooperative: through continued financial and technical support, PacifiCorp assisted the OSU project to expand wind monitoring in the region. The Research Cooperative uses financial resources of its members to purchase equipment, collect data from stations, and analyze the data. These data gathering efforts are fundamental to the future success of the region's wind industry.

6) Clean Coal Technologies goal from RAMPP-4 Action Plan: The RAMPP-4 action plan identified a need to continue to evaluate clean coal technologies, including IGCC and fluidized bed, for their ability to meet resource needs in an environmentally acceptable way and at low cost.

Performance: During 1996 PacifiCorp monitored industry activities regarding clean coal technologies. Most of the activity centered on integrated coal gasification combined-cycle (IGCC) technology developments in this country and abroad. Pressurized fluidized bed combustion (PFBC) technology development has largely been stalled.

PacifiCorp's 1996 Clean Coal Technology monitoring activities included participation in the Gasification Users Group (GUA), the Wabash River Interest Group (WIG) and attendance at the annual Gasification Technology Conference (GTC) in San Francisco, California.

The first GUA meeting was at the site of Tampa Electric's 250 MW IGCC plant. The meeting included a tour of the plant, technical presentations and a question-and-answer period. The plant initiated startup activities in 1996 and has experienced no significant operating problems. The 25 MW hot gas cleanup unit (HGCU) pilot should begin testing in 1997.

The second GUA meeting, in May, was in Europe at three separate Gasification facilities. PacifiCorp did not attend the European meetings but obtained copies of the handouts. Site visits for participants at the conference included tours of the 335 MW Puertollano IGCC plant in Spain, the 250 MW Demkolec IGCC plant in Holland, and the biomass 16 MW IGCC plant in Sweden.

Several operating difficulties at the Wabash plant required rescheduling the meeting there until Spring of 1997. Wabash River startup activities, initiated in 1995, continued through 1996. The primary problem area has been breakage of ceramic candle filters in the particulate removal system. The other major difficulty has been an unexpected chloride poisoning of catalyst beds and subsequent chloride stress corrosion cracking in downstream heat exchangers.

The annual GTC in San Francisco included presentations of gasification projects from all over the world. Highlights from some of the presentations follow:

- The 100 MW Pinon Pine IGCC plant near Reno, Nevada, is 90 percent complete. This project will demonstrate an air-blown gasifier supplied by M.W. Kellogg and manufactured in Salt Lake City. Primary sulfur capture will be by limestone in the gasifier vessel. Downstream hot gas clean-up vessels will provide the remainder of the 90 percent sulfur removal. The project should receive a $1.00/MMBtu tax credit.

- The other major gasification projects reported on at the conference primarily focused on refining and chemical plant installations where clean coal technology will be the major portion of the plant. Six IGCC plants are in various phases of design and startup in the U.S. and Europe.

- EPA has granted Texaco gasification technology exemption from the Resource Conservation Recovery Act (RCRA). Because of this ruling, Texaco can use hazardous waste generated by the refinery as feed to the IGCC instead of disposing it in incinerators or other off-site alternatives. Additional synergies occur from using the existing refinery waste water treatment unit and sulfur recovery system.

- The Italian Government passed legislation to provide price incentives for IPP projects that use indigenous fuels. As a result, four major refinery-based IGCC projects are underway.

- A 110 MW IGCC plant is nearing completion in Pernis, Netherlands will supply hydrogen to the refinery to produce low-sulfur transportation fuels. Recent IPP legislation passed in Japan resulted in development of two IGCC plants associated with refineries. Other countries where IGCC projects are in planning stages include England, Germany, Korea, India and the U.S.

Biomass projects in this country and abroad are using clean coal technology. A 200 tons per day (TPD) biomass gasification plant is scheduled for a 1997 startup in Burlington, Vermont. A 100 TPD biomass gasification plant in Maui, Hawaii is installing a new feed system and should restart in March 1997. A black liquor gasifier is expected in North Carolina and NREL has awarded funds for a 60 MW alfalfa based gasification plant in Minnesota.

7) Other Opportunities goal from RAMPP-4 Action Plan: The RAMPP-4 action plan identified a need to identify and pursue cost-effective resource acquisition opportunities that meet the future needs of the company.

Performance: PacifiCorp continues to look at transactions and other strategic alliances with other utilities and other markets that would bring value to customers and shareholders. One example is an agreement to market power and manage resource services for Deseret Generation & Transmission Co-operative (DG&T). DG&T is an electric cooperative based in Sandy, Utah. It serves 36,000 customers of six distribution cooperatives in Arizona, Colorado, Nevada, Utah and Wyoming. DG&T selected PacifiCorp from a field of bidders in August to market its excess electrical capacity and provide other services under a five-year contract.

PacifiCorp will dispatch power from DG&T's major resources to serve DG&T's customers. Those resources include a share of the Hunter plant in central Utah, and the Bonanza plant. Bonanza is a coal-fired plant about 40 miles south of Vernal, Utah. PacifiCorp will provide resource management services, which include control area services, scheduling and dispatch service, and billing and accounting service. PacifiCorp will assume control area obligations for approximately 240 MW of firm member loads, 360 MW of firm non-member loads, and 728 MW of dispatchable generation resources. PacifiCorp will act as agent for DG&T in electronically posting and selling available transmission capacity of DG&T. PacifiCorp will provide power marketing services for up to 250 MW of excess power for DG&T, including purchasing specified amounts of DG&T's excess generation and assisting DG&T in marketing it to third parties.

8) Competitive Market goal from RAMPP-4 Action Plan: The RAMPP-4 action plan identified a need to continue to be a low-cost provider and a successful competitor in the marketplace.

Performance: The short-term power market in 1996 continued to see low prices due to substantial amounts of low-cost hydro energy available in the West and low natural gas prices, resulting in fierce competition for this near-term market. Examples of PacifiCorp's continued activity in the marketplace include the following:

- PacifiCorp has agreed to increased power sales to Clark Public Utilities.
- PacifiCorp and Energy Services Inc./Vanalco Aluminum (DSI) agreed to extend an existing 50 MW sale for one additional year commencing October 1, 1996.
- PacifiCorp and Energy Services Inc./Kaiser Aluminum have agreed to extend and expand the current 50 MW one-year contract that was due to end March 31, 1997. The extended transaction will be a 100 MW sale beginning January 1, 1997 and will continue through December 1999.

9) IRP goal from RAMPP-4 Action Plan: The RAMPP-4 action plan identified a need to continue to improve the RAMPP process and work to modify IRP to be a more effective tool. This included several sub-items: a) implement feasible process improvements identified in the RAMPP-4 regulatory acknowledgment review; b) evaluate other IRP models to assess the relative benefits of code improvements to IPM versus a different model to achieve the goals of RAMPP-5; c) evaluate the implication of the FERC NOPR for resource planning and implement appropriate changes to RAMPP modeling; d) work with regulatory agencies and other parties to modify IRP to make the process more valuable to utilities and their customers.

Performance: The company continues improving the RAMPP process and working to make it a more effective tool.

a) Implement feasible process improvements identified in the RAMPP-4 regulatory acknowledgment review: the only state that has provided recommendations on process improvements through its RAMPP-4 acknowledgment process is Oregon. The Oregon Public Utility Commission's Order No. 96-159 acknowledging RAMPP-4 included the following recommendations:

- Discussion in RAMPP-5 of the company's hydro relicensing efforts with FERC, including environmental and operational uncertainties as they relate to the North Umpqua and other Pacific hydro facilities.

  Response: The company plans to include this discussion in its IRP report to be filed at the end of 1997.

- In RAMPP-5, analysis of the future power market and the resulting implication regarding acquisition of supply-side resources.

  Response: During the first half of 1997, the company will prepare sensitivities to explore this issue, along with sensitivities exploring other issues, and will report the significant results in its IRP report to be filed at the end of 1997.

b) Evaluate other IRP models to assess the relative benefits of code improvements to IPM versus a different model to achieve the goals of RAMPP-5: the company stays informed of alternative IRP models available in the marketplace. So far, no other model except the current IPM model from ICF Resources is available that offers a better combination of two critical elements for PacifiCorp's IRP modeling: sufficient flexibility in specification of geographic areas and their interconnections, and adequate documentation and support.

c) Evaluate the implication of the FERC NOPR for resource planning and implement appropriate changes to RAMPP modeling: the primary implications of the FERC NOPR for resource planning is in potential changes to transmission paths. The company has begun to incorporate these changes into its IRP modeling by allowing for a stepped function for transmission availability. The Update modeling assumed that the contract amount of capacity was available on each path, and an additional amount would be available at a price consistent with existing contracts. As additional FERC rules become known, the company will make additional modifications to its portrayal of transmission paths and availabilities.

d) Work with regulatory agencies and other parties to modify IRP to make the process more valuable to utilities and their customers: the company's change to its IRP process as embodied in this Update is a major attempt to make the IRP process more valuable to utilities and customers. By updating input assumptions more frequently, and providing the results of that updating annually, the company has more up-to-date planning information to use in its decision making, regulatory staffs have more current information to use in their oversight work, and customers have more up-to-date information on the cost of alternative power sources.

PacifiCorp will now turn to development of sensitivities using this new base case. The company will work with its public advisory group to determine the sensitivities and to review the results of analyses of those sensitivities. In the summer of 1997, the company plans to again update modeling inputs and prepare a new base case. The report planned for the end of 1997 will include results of that new base case, as well as a summary of results of the sensitivities done in the first half of the year and its base case. This will allow a comparison of two base cases, one developed in the fall of 1996, and one developed in the fall of 1997.

Resource and Market Planning Program
RAMPP - 4

NOVEMBER, 1995

PACIFICORP

PacifiCorp
RAMPP-4 Report

Table of Contents

PacifiCorp
RAMPP-4 Report

List of Tables

Chapter 4

Chapter 5

Chapter 6

Chapter I: Introduction

This report summarizes PacifiCorp's fourth Resource and Market Planning Program (RAMPP-4), the company's integrated resource planning process. It documents the internal and external processes used by PacifiCorp to analyze future load growth; the ability of its existing power plants to meet customers' electric energy service needs; and the need for new resources, including new power plants, power purchases and customer efficiency programs. Unlike previous RAMPP reports, the RAMPP-4 report is not a stand-alone document. Rather, it accompanies and is an update to the RAMPP-3 report. Copies of the RAMPP-3 report are available by calling (503) 464-5620.

PacifiCorp provides electricity and related energy services to 1.3 million customers in seven Western states: California, Idaho, Montana, Oregon, Utah, Washington and Wyoming. Almost half of the company's retail sales are to industrial customers; about one fourth to commercial customers, and about one fourth to residential customers.

PacifiCorp's RAMPP process serves two primary purposes:

1) It provides a long-range plan and framework to guide the company in evaluating resource and market decisions;

2) It complies with regulatory commission requirements for integrated resource planning (IRP). Chapter 2 discusses these regulatory requirements.

Overall, PacifiCorp's RAMPP process aims at minimizing costs and risks to customers, and providing value to the company's shareholders. The goal is to achieve the lowest possible cost in providing electricity services to customers, while recognizing the appreciable uncertainties affecting future requirements and power sources. The primary accomplishment of the planning process is in the process itself -- the understanding, insights, and information it generates -- rather than in any specific set of actions identified. In addition to providing a consistent framework of assumptions and analyses that aid decision making, the IRP process has had other beneficial effects. It has improved communication with regulatory staffs, improved communication within the company, and improved coordination among the various models the company uses.

RAMPP provides an overall long-range look at the company's resource position, identifies strategies that merit additional analysis, and provides a framework for the analysis of specific resource opportunities. This requires an understanding of the marketplace in which the company competes and the risks to customers and shareholders. Several of the commenters on the draft report raised the issue of risk. The company did not sufficiently address risk in the draft report, and has corrected that in this final version. The issue of risk is addressed later in this chapter in the section on Perceptions, and at the end of the Results chapter.

The company firmly believes it is critical to retain flexibility to respond to changing conditions. A plan cannot provide every answer to every question, but it can help guide ongoing decision making. Therefore the action plan includes flexible responses the company can make as conditions change, rather than pre-determined schedules and amounts of resource acquisitions.

History of RAMPP-4

PacifiCorp held the first public advisory group (RAG) meeting for RAMPP-4 in the summer of 1994. At that meeting PacifiCorp proposed postponing the RAMPP-4 completion date from December 1995 to December 1996. The company requested the delay for two reasons: (1) Since PacifiCorp is planning to add the 474 MW Hermiston plant to its system in 1996, the company will need few additional resources before 2000; and (2) PacifiCorp felt that little new information or insight would be gained by conducting the RAMPP-4 analysis so soon after RAMPP-3. The RAG participants wanted an earlier completion date to establish demand-side management (DSM) targets past 1995. PacifiCorp agreed to this accelerated schedule with a completion date of late 1995. The RAG participants also suggested a three-year action plan, to provide some overlap in action plans with the next RAMPP report, which the company will prepare in two years.

The accelerated schedule required a shorter work plan. Therefore, the analyses performed for RAMPP-4 included only 39 cases, rather than the 155 cases in RAMPP-3. The company believes 39 cases are sufficient to confirm that the lessons learned from the RAMPP-3 results still apply, while leaving room to include important changes since RAMPP-3 and explore significant issues that have arisen since then. The accelerated schedule also required a shorter RAMPP report. Therefore, the RAMPP-4 documents include only the main report and one appendix. The RAMPP-3 report provides background information about PacifiCorp's system and planning assumptions.

PacifiCorp's Perceptions of the Future

Any planning activity reflects the perceptions of an organization about its operating environment. PacifiCorp management's perceptions of the energy marketplace and the electric utility industry affect its view of resource planning. Understanding these perceptions can help interested parties see the logic behind the RAMPP-4 action plan. RAMPP-4 was able to incorporate some of the implications of changes in the industry; RAMPP-5 will be able to incorporate more. Following is a summary of PacifiCorp's key perceptions about future trends in the industry, followed by a discussion of each.

- Competition: Competition for service to PacifiCorp customers will continue to intensify with more and more choices available to customers.

- Regulation: Over the next five years, state regulation of electric utilities will continue to change to reflect a more competitive environment.

- Transmission: Full open access to the nation's transmission system will be in place within a few years.

- Wholesale Market as a Resource: Electric utilities will be able to increasingly rely on power purchases in the wholesale market to meet their power needs.

- Wholesale Market Revenues: Increasing involvement in the wholesale market will mean greater rewards as well as greater potential risks.

- Risk: The trends identified above will lead to increased risk in the company's business environment.

- Integrated Resource Planning (IRP): As the electric utility industry evolves into a competitive market, the need for detailed resource planning under regulatory commission oversight will decrease.

- Timeframe: The planning horizon will shrink as the pace of change increases in the marketplace.

- Social Objectives and the Environment: Society will have a more difficult time achieving its social and environmental objectives through energy providers as competition imposes tighter cost constraints.

Competition

Competition for customers' business has increased dramatically over the past decade and will continue to increase. PacifiCorp believes the electric utility industry is in transition from a regulated monopolistic environment to a competitive market. Competition and regulatory changes at the federal level are removing barriers to entry into the electric utility industry. Competition increases choices, which is good for customers. PacifiCorp welcomes competition. According to economic theory, competition is an efficient way to organize industry when there are a larger number of buyers and sellers, and information is readily available. Competition creates pressure for suppliers to meet customer needs and expectations or be driven from the market.

PacifiCorp expects retail wheeling will exist in some form throughout the company's service territory within five years. Even without retail wheeling, PacifiCorp is facing increasing competition. Customers are shopping around for the best products, service and price. Their energy supply choices include self-generation, independent power producers (IPPs) willing to serve individual customers or groups of customers, other fuels, and electricity brokers and marketers. New players, new products, and rapid deal making are becoming common in the market. PacifiCorp expects customers to increasingly turn to power marketers, who are willing to offer lower prices and accept more risk to get established with customers.

As the market becomes more efficient, more power will be available and prices will drop. PacifiCorp believes the West will have excess power supplies for at least five to seven years, and possibly ten. Two trends support this prediction: the level of existing capacity and prospects for new generation. The WSCC capacity factor in 1994 was around 60 percent, indicating that generating utilities could produce considerably more power from existing power plants. As transmission access increases, more of that power will be available to a wider market.

In addition, new generation will come on line in the next few years. In the Pacific Northwest, more than 1,600 MW of new generation (primarily gas-fired cogeneration or combined cycle facilities) could come on line by 1997-1998. The development of merchant plants (built by independent developers who then sell the output to utilities and large commercial or industrial customers) increases the amount of power available to utilities and customers. The developers of merchant plants believe they can profitably sell low-cost power that relies on low gas prices and the low heat rate of combined cycle plants.

Following are some of the recent events and trends that reflect increasing competition in the marketplace:

- Wholesale purchasers have more suppliers to choose from who offer new generation at prices competitive with PacifiCorp's embedded generation costs. Over 100 power marketers have registered with the Federal Energy Regulatory Commission (FERC). Over eighty marketers and brokers have entered the market just in the last year.

- An electric futures market with indices for the California Oregon Border (COB) and Palo-Verde is under development and should be active in 1996.

- PacifiCorp has signed two energy service agreements with the Clark Public Utilities District. The first will provide backup and other ancillary control area services for Clark's upcoming cogeneration project. The second is a traditional power sale to bridge the time until Clark's new unit comes on-line.

- Willamette Industries, a 42 MWa retail customer of PacifiCorp in Oregon, has decided to self-generate to save on energy costs. Being one of the lowest cost producers in the country gives PacifiCorp a strategic advantage, but it has not made the company immune to losing customers. PacifiCorp is losing a significant load, even though it will be providing ancillary services to Willamette.

- In an effort to become more competitive, BPA has reorganized itself, proposed legislation to refinance its debt, tried to avoid additional conservation and fish and wildlife expenditures, and announced significant workforce reductions. Concerns about BPA's ability to prevent future price increases are causing many of its customers to consider switching to other suppliers. BPA has countered with a rate case proposal that reduces its prices to direct service industry (DSI) and preference utility customers at the expense of the region's investor-owned utility (IOU) residential exchange customers.

- The California Public Utility Commission is conducting hearings on restructuring the electric utility industry in the state. The earliest date for an order under their current schedule would be December 1995.

- The Utah Public Service Commission held three public meetings to address restructuring in the electric utility industry.

- Most states are now considering, either through legislation or regulatory proceedings, some form of retail wheeling or regulatory restructuring.

- When retail wheeling occurs, there will be intense competition for a large amount of industrial load in the western United States. Industrial customer groups are pressuring Congress to open utility transmission and distribution systems to give them more power supply choices. Such competition would mainly be price driven.

- A majority of residential space heating customers already have an alternative fuel system installed in their homes as a backup and available to use.

- Cogeneration suppliers frequently approach many large industrial customers because they are prime candidates for cogeneration and self-generation.

Based on these and other occurrences, PacifiCorp believes it will be conducting future resource planning in an increasingly competitive environment. That environment will force the company to consider both the short-term and long-term price impacts of resource planning decisions. PacifiCorp believes that higher prices in the short-term will cause customers to choose other energy providers. Once customers go to another supplier, it is very difficult to get them back. Therefore, in evaluating modeling results in RAMPP, the company looks at both short-term and longer-term price impacts.

Regulation

PacifiCorp expects that over the next five years, alternative forms of regulation will become critical to successful electric utilities. Traditional rate-of-return regulation will impede utilities' ability to compete and will block the flow of benefits to customers. The company is confident that regulators and utilities can find alternatives to the current form of regulation that are satisfactory to both parties and beneficial to customers. Such alternatives can ensure the availability of power to core customers at fair and reasonable prices, while still providing an incentive for the company to pursue efficiencies and innovations that increase earnings. As competition increases, the need for regulation diminishes. Because competition is growing over time, regulation must change not just once, but continuously.

Several of the states served by PacifiCorp (including California, Montana and Utah) are conducting proceedings on regulatory change and the restructuring of the electric utility industry. PacifiCorp believes a competitive marketplace will give utilities incentives to find more operating efficiencies and innovations as a way to reduce costs. A competitive rather than highly regulated market will lead to greater economic efficiency, lower prices for customers, and the potential for enhanced shareholder benefits.

PacifiCorp's management believes current trends in the wholesale market illustrate the need for an alternative form of regulation. Increased activity in the wholesale market brings greater benefits, but also greater risks. If shareholders are to assume those risks, they should also receive the benefits. Utilities will have little incentive to assume such risks unless an alternative form of regulation allows benefits commensurate with those risks to flow to shareholders.

PacifiCorp recognizes the benefits that regulation has provided: safer workplaces; cleaner air; more energy-efficient appliances, homes, and businesses; and reliable electric service. Where regulation continues to provide benefits, it should be preserved. Where regulation impedes the workings of a competitive marketplace, it should be revised. Tomorrow's marketplace should be open and competitive, giving customers the option to choose their supplier and services.

Transmission

PacifiCorp believes that full open transmission access will be in effect nationwide within a few years. The conditions FERC imposed on the Utah/Pacific merger reduced PacifiCorp's control of its own transmission system. Now FERC is expanding those provisions and rapidly extending them to all utilities. In approving various filings, FERC has been requiring comparability tariffs that would give transmission access to third parties at prices, terms and conditions comparable to those the owning utilities apply to themselves.

The FERC Notice of Proposed Rulemaking (NOPR) replaces this piecemeal approach with a systematic opening of the system to all utilities. To broaden the existing open competition for wholesale power sales, FERC declared that all 137 public utilities that own transmission systems in the United States file comparability tariffs for transmission and ancillary services. This will open transmission access to third parties. Each utility will file terms and prices for wheeling electricity across their transmission lines. This will eliminate the need for utilities and other suppliers to negotiate transmission access because the new FERC rules will require the transmission-owning utilities to transmit other providers' power on the same terms as their own.

Under FERC's proposed rules:

- All transmission-owning utilities must file non-discriminatory open access tariffs, making their transmission available to all wholesale sellers and buyers.

- All transmission-owning utilities must offer unbundled ancillary services separately from their traditional power-moving wheeling service.

- Utilities must use these tariffs for their own wholesale sales.

- Utilities will establish real-time information networks (RINs). FERC has called for a technical conference to standardize electronic bulletin boards.

- Utilities will have the opportunity to recover stranded costs (prior investments that cause the utility's prices to be higher than market rates).

FERC had planned on issuing a final ruling towards the end of 1995, but as a result of increasing pressure to perform an Environmental Impact Statement (EIS), it recently agreed to conduct an EIS before proceeding further. The EIS is scheduled for completion in March of 1996. PacifiCorp expects a final ruling in the second quarter of 1996 or later.

PacifiCorp anticipates that new FERC rules could have multiple consequences. Which will occur is unknown now, but the following are some of the possibilities:

- Accelerated use of the transmission system. At some point, information on all transfer capabilities will be available to anyone who wants it. This is one of FERC's goals. As a result, there will be more wholesale sales and purchases.

- Deregulation of the generation portion of the business.

- Vertical disintegration of utilities into generation, transmission, and distribution companies, perhaps followed by horizontal re-integration of two or more utilities. (Two or more generation companies could combine to form one large generation company.)

- Loss of distinction between firm and non-firm power.

- The elimination or reduced importance of capacity products as more utilities rely on the non-firm market for their power needs.

- Development of a new market for generation-based ancillary services such as load following, reactive power supply, area balancing, loss compensation, scheduling and dispatching, system protection and others. PacifiCorp and others are proposing that these generation-related ancillary services be subject to market control and pricing, similar to the treatment accorded bulk power generation.

- Generally lower, but possibly higher, power prices. PacifiCorp expects to see prices affected within a year of completion of the rulemaking, which should be in the first quarter of 1996.

- More uncertainty about the future benefits for a utility building new transmission facilities.

- Need to adjust resource planning.

Which of these consequences occurs, and how, will depend on what FERC writes in the rules. PacifiCorp supports open access, but believes there are competitive markets for some ancillary products and services that require consideration as the open access debate continues. The end objective is to create a fully competitive marketplace for electric power where buyers and sellers can negotiate without impediments. For comparability to be successful, all transmission owners will have to provide open access to their transmission systems at terms, conditions and prices comparable to those it provides itself. PacifiCorp is advocating competitive pricing of generation-based ancillary services and "up-to" pricing for non-firm wheeling services. The company expects FERC to continue using traditional embedded cost of service principles for firm wheeling pricing.

PacifiCorp filed comparability tariffs with FERC on June 19, 1995. These tariffs allow for firm and non-firm transmission services as well as ancillary services such as load following and reactive power support. Also, the tariffs provide for an electronic information system that will provide transmission price and availability information to all potential users of the transmission network. The tariffs will not become effective until approved by the FERC.

The Western Regional Transmission Association (WRTA) and PacifiCorp are leading an effort to produce a single regional standard for RIN that will cover the entire market area. Such a RIN will make it possible for all participants to execute transactions expeditiously.

The new rules require PacifiCorp to operate its transmission system more like a common carrier, much like the natural gas pipelines. By limiting the way the utility can use its transmission system, it imposes a "wall" between the power side and the transmission side of the utility. The company will not be able to use its transmission system to secure a competitive advantage. On the other hand, a more open national transmission system will give PacifiCorp greater access to the transmission systems of other utilities.

It is uncertain what kind of return PacifiCorp will be able to get from existing and new transmission investments. FERC will probably continue to require transmission-owning utilities to use embedded pricing (based on the cost of existing investments) rather than market-based pricing. The embedded pricing could be "postage stamp" prices (i.e., one charge regardless of the distance traveled) or "locationally sensitive prices" (i.e., charges vary with the distance traveled or with differences in spot prices across the network). Any use of the company's transmission system for its own transactions reduces the amount of potential revenue it can derive from other parties using its transmission system. Because of these trends, the company will carefully evaluate any transmission expenditures or investments.

New FERC rules will have consequences for resource planning. With all the changes occurring, PacifiCorp will have to re-examine its assumptions for transmission constraints and resource siting. RAMPP-5 will evaluate the impact of new FERC rules on the company's resource requirements.

Wholesale Market as a Resource

Because of changes occurring in transmission and in the power generation business, PacifiCorp expects to be able to increasingly rely on the wholesale market to meet its power needs, both from the non-firm market and from longer-term contracts. Power purchases give the company more flexibility in the way it can meet the energy needs of its customers. If the price of power on the wholesale market is very attractive and other conditions are right, the non-firm market could allow the company to delay other resource acquisitions. Similarly, longer-term contracts on the wholesale market can sometimes provide more cost-effective solutions to system needs than building a new power plant. RAMPP-5 will contain more market-based resources than did RAMPP-4.

PacifiCorp also recognizes that a more market-based strategy could carry higher risks, because even though spot prices are sometimes low, they are sometimes high as well. Spot market prices can fluctuate significantly depending on daily and hourly supply and demand. Decisions about whether to use the non-firm market for power for retail customer needs will have to weigh potential short-term price advantages against the longer-term price stability of the company's own generation assets. With the increasing availability of power from the wholesale market, the company will compare any new resource acquisitions with the costs, benefits, and risks of meeting the same resource needs with firm and non-firm power from the wholesale market.

Wholesale Market Revenues

In the past, wholesale sales were a minor part of PacifiCorp's total revenues. The company used the revenues to help offset retail prices. However, several changes are occurring: 1) wholesale is becoming a larger part of the company's total business, 2) wholesale prices are declining, and 3) that part of the business carries increasing risks and potential rewards.

The wholesale part of the business is growing rapidly and the company is looking at wholesale sales as a major business activity. Wholesale marketing will increasingly evolve as a separate business with its own strategies, rewards and risks.

As the wholesale market is becoming more efficient, prices and margins are falling. In the past, PacifiCorp has successfully used margins from wholesale revenues to reduce retail prices. This will become increasingly difficult as wholesale prices and margins decline. The California-Oregon border (COB) and the Palo Verde power plant in Arizona are major transmission interconnection points. Prices at those two locations are reliable indicators of the wholesale market in the West. These two points will serve as industry measures for western electricity futures and indices. In 1992 and 1993 non-firm sales prices at COB stayed between \$27 and \$29/MWh; at Palo Verde they stayed between \$19 and \$24/MWh. In 1994 both averaged around \$23/MWh, higher in the early part of the year and lower in the later part of the year. For the first three months of 1995, the range for COB was \$13 to \$16/MWh; at Palo Verde it was \$15 to \$18/MWh.

The greater the company's activity in the wholesale market, the greater the potential rewards and the greater the risks. Those who bear the risks should also benefit from the rewards. The company would prefer to not expose retail customers to the higher risk/reward situation. Equity capital is a better place for such activities. The company will experience upward pressure on retail rates if it cannot maintain the current level of wholesale contribution. Changing conditions in the wholesale markets mean the company must take on greater risk to achieve the same level of wholesale contributions. However, the company continues, for now, to use the retail credit approach for wholesale sales. These are transition times, and that approach may change in the future as other changes occur, some expected and some unforeseen. These changes could include alternative regulation, deregulation, and restructuring.

Risk

The trends identified above will lead to increased risk in the company's business environment. PacifiCorp recognizes that the future will be more risky than the past. The relatively stable path that the industry has been on -- with stable to declining prices -- will be a challenge to maintain for the future. There is less assurance that today's customers will be tomorrow's customers. There is less assurance that an asset that seems like a good investment today will still seem like a good investment in a few years. There is less assurance that today's prices for wholesale power will be a reliable predictor of tomorrow's prices for wholesale power. There is less assurance that the company's transmission system will help reduce risk.

There is no way to avoid some of these risks. They are part of the increasingly competitive environment in which the company must operate. Although the company would like to shield both its customers and its shareholders from these risks, that is unrealistic. The company is concerned about these increasing risks and is developing methods to evaluate the risk of alternative strategies. RAMPP-5 will include more analysis of risk.

The investment community is well aware of increasing competition in the electric utility industry. They consider all electric utilities riskier now than they did just a few years ago. This means that the company's cost of capital is higher and will become higher in the future as competition increases. This pressure from the financial community occurs just at the time that one of the traditional means the company has used to keep prices down -- margins on wholesale transactions -- is becoming less effective. Traditionally, the company used revenue credits from wholesale sales as well as efficiency improvements and cost reductions to offset the need for retail price increases. However, margins on wholesale sales are now much thinner than they have been, reducing the revenue credit offset. It will become even more risky to enhance, let alone maintain, margins on wholesale transactions. In addition, to prosper in a more fully competitive market, the company needs to aggressively pursue transactions with new wholesale customers and develop new products and ancillary services. These new products and services will carry more revenue risk than did traditional energy and peak products.

why

Along with increased risks come the potential for increased rewards. One of the impacts of changes the company is experiencing and seeing for the future is in the risk/reward symmetry that utilities have operated under. Who should take on any particular risk, customers or shareholders, is probably less important than that there is risk/reward symmetry. Whichever party benefits from the rewards of a particular strategy should also take on the risks. PacifiCorp is willing to take on the risk of many factors for its shareholders, particularly those over which the company has control, as long as the company can in turn capture for its shareholders the rewards of successfully controlling costs.

cost — that's not a risk. — bear the cost of shouldering the risk

is any this [illegible] the one who pays the [illegible] in between [illegible] cost accept [illegible] a risk should reap the rewards

An area of risk receiving wide discussion is stranded costs. The issue of strandable assets and strandable benefits is a longer-term problem. It is bigger than any one company. There are important legitimate issues involved, but it is not reasonable to expect utilities to make large investments today that may drive customers away or not be recoverable in the long term. This is why PacifiCorp is sponsoring the "financing conservation in a competitive environment" project to explore ways to ensure that important issues such as DSM are not casualties of the competitive environment. This is also why PacifiCorp is hesitant to make large capital investments without some assurance of associated revenues from those investments.

Integrated Resource Planning (IRP)

IRP will evolve as the industry changes. Planning for future resources will continue to be relevant for the regulated, non-competitive part of the industry, but not for the competitive segment. With competition, the market acts as an oversight agency. Only those who plan effectively get to stay in the game. The way in which IRP changes will depend partly on how much of the industry remains regulated. IRP can be tailored to that part.

For example, if extensive restructuring occurs and retail customers have access to competitive suppliers, or if the industry or a utility is functionally disaggregated, then IRP can focus on the need to provide retail service efficiently and at low cost to those customers who do not have choices. It would involve a review of the balance between demand-side and supply-side services, between short-term and long-term agreements with suppliers, and between price impacts and benefits. The last section of Chapter 2 discusses some possible ways in which IRP could evolve.

Timeframe

PacifiCorp believes that as the pace of change picks up, it will be very difficult to plan more than five to ten years ahead because of market uncertainties. A more open market is changing the industry and shortening the decision-making timeframe in the resource planning environment. The changes occurring in the electric industry suggest that today's assumptions may be outdated in five to ten years. As competition increases, the company's customer base will change, as will other pressures on the business.

PacifiCorp has carefully tracked the changes that have occurred in the natural gas industry due to increased competition. In that industry, an open market has created radical shifts in supply and price forecasts. Today the gas industry considers a two-year contract long-term. A competitive market makes forecasting very difficult and more unreliable for longer planning horizons.

For example, current DSM planning assumes that existing customers will remain on the regulated utility's system for 20 years or more. However, as the marketplace becomes more competitive, some customers may not stay on the utility's system. The utility system may never receive the full benefits from its DSM investments at some customer locations. In addition, other assumptions about the future may prove inaccurate, leading to potentially stranded investment.

The RAMPP-4 analysis used a 20-year planning horizon with an additional 30 years to account for end effects. However, the discussion in the RAMPP-4 report and the results used to develop the RAMPP-4 action plan focus on results for the first 10 years.

Social Objectives and the Environment

One of the original goals of IRP was the full consideration of certain social and environmental objectives. PacifiCorp does not believe social and environmental goals need be a casualty of competition. However, it will be increasingly difficult for society to achieve social and environmental objectives through energy providers.

Any mechanism to achieve social and environmental objectives that adds to the cost of energy will need to include all energy providers. Otherwise, it will interfere with the competitive market by increasing the upward pressure on prices for only one sector of energy providers: the sector subject to regulation. Achieving those objectives through resource planning decisions of the regulated utilities can trigger retail price increases that threaten the regulated utility's position in a competitive environment. If one supplier has higher prices because of environmental costs not borne by other suppliers, customers will likely choose the lower cost supplier who does not have to meet such objectives. This will thwart the original objectives.

Although the company is concerned with competitive impacts, it also believes sound environmental stewardship is an investment in the long-term health and economic vitality of its service area, and, therefore, an investment in its own success. The company seeks solutions that make sense from a business as well as an environmental standpoint -- approaches that will help the environment while also making the company more competitive. The company's environmental goal is to be a creative force in enhancing the communities served and improving the environment. The goal includes objectives related to energy efficiency, renewable resources, and the demonstration of CO_2 offsets as a cost-effective technique for addressing CO_2 emissions.

DSM provides a way to achieve both environmental and competitive goals. The company uses the Energy Service charge for DSM programs to assure that those who benefit from efficiency measures pay for them. This provides a way to achieve DSM while minimizing the price impact of DSM programs. PacifiCorp sees an increased need to have participants pay for DSM investments and to find funding mechanisms that do not affect the utility's competitive position. The company is also actively investigating alternative funding mechanisms for DSM.

There are low-cost ways to address environmental concerns. The company's pilot wind, solar, and CO2 offset projects suggest low-cost solutions. These approaches can also position the company for future uncertainties. However, PacifiCorp believes it is unlikely that the federal government will require a tax or reduction in CO2 emissions in the next 10 years. The 1994 Congress was unable to pass any form of an energy tax. Any federal law that addresses this issue will most likely take a form similar to the Clean Air Act, giving utilities some flexibility in how to comply.

The company's renewable activities aim at testing the cost-effectiveness of technologies that offer environmental benefits. This goal is behind its activities in geothermal (the Blundell plant operating in Utah), wind (the Foote Creek plant planned in Wyoming and the Columbia Hills plant planned in Washington), and solar (the Solar II test project operating in California and four photovoltaic projects in PacifiCorp's service territory). The company is willing to pay a small premium over the cost of gas-fired alternatives, generally less than 10 percent, for renewable projects. The exact amount would depend on the project: its potential to provide valuable information and its non-price attributes.

PacifiCorp began its Green Corps program in 1993. It offers a way for employee groups to develop and implement environmental projects in their communities. Through the program, employees design projects and apply for company resources to carry them out. The employees work side-by-side with community groups to achieve the improvements. Each year, PacifiCorp provides contributions to 30 local environmental projects that employees create and nominate for the funding. The total allocation to Green Corp is $60,000 a year.

RAMPP-4 Action Plan Summary

RAMPP-4 includes a new action plan for PacifiCorp for 1996, 1997, and 1998. These actions are intended to position the company to provide low-cost electric service to customers given a range of future load, resource, and market uncertainties. Chapter 6 provides a full description of the RAMPP-4 action plan.

Demand-Side Resources:

> **Achieve 23 MWa of installed cost-effective savings by 1996; 25 MWa by 1997; and 28 MWa by 1998.**

Peaking:

> **Evaluate alternative ways to meet peaking needs and pursue opportunities that meet system needs cost-effectively.** PacifiCorp needs no new winter peaking resources until 2003. However, the system may need summer peaking resources beginning in 2002.

Gas-Fired Resources:

> **Evaluate alternative ways to meet baseload needs and pursue opportunities that meet system needs cost-effectively.** PacifiCorp does not need new baseload resources until 2003 or later.

Preparing for the Future:

> **Continue to implement cost effective system improvements to the generation, transmission and distribution systems.**
>
> **Pursue low-cost activities that will increase the company's knowledge about renewable resources.**
>
> **Continue to evaluate clean coal technologies, including IGCC and fluidized bed for their ability to meet resource needs at low cost and in an environmentally friendly way.**
>
> **Seek and pursue cost-effective resource acquisition opportunities that meet the future needs of the company.**

Continue to be a low-cost provider and a successful competitor in the marketplace.

Continue to improve the RAMPP process and work to modify IRP to be a more effective tool.

Organization of the Report

This document reflects the order of activities involved in preparing RAMPP-4. Chapter 2 discusses the regulatory requirements for RAMPP-4. Chapter 3 updates the modeling and input assumptions from RAMPP-3. Modeling results in Chapter 4 demonstrate how the company would manage an efficient balance of resources to meet customers' future electric service needs under alternative futures. Chapter 5 discusses the company's performance on the RAMPP-3 action plan. Chapter 6 discuss the RAMPP-4 action plan. An index after Chapter 6 provides page references for various issues or topics in the report. The Technical Appendices includes more detailed information on the input assumptions and analyses. Copies of the Technical Appendices are available by calling (503) 464-5620.

Chapter 2: Regulatory Requirements

This chapter reviews the integrated resource planning (IRP) guidelines as established by state regulatory Commissions. It also lists the requirements for RAMPP-4 from the RAMPP-3 acknowledgment reviews by the Washington, Oregon, Utah, and Montana Commissions and the company's response to each requirement. The chapter concludes with a discussion of how IRP could evolve as the industry and regulation change.

IRP Regulatory Requirements

This report, along with the Technical Appendix, complies with regulatory commission requirements for integrated resource planning in Idaho, Montana, Oregon, Utah, and Washington. Guidelines established in those states require the company to:

- Examine a range of forecasts for electricity demand and incorporate other uncertainties in the analysis;
- Consider all feasible alternatives for balancing resource supply with electricity demand;
- Assess supply and demand alternatives in a consistent manner;
- Assess possible impacts on external costs in evaluating resource alternatives;
- The goal should be least cost to the utility and its customers consistent with the long-run public interest;
- Describe 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
- Prepare the plan with substantial public involvement.

The RAMPP process at PacifiCorp involves several departments. They include Integrated Resource Planning, Transmission and Resource

Planning, Demand-Side Policy and Strategy, Power Supply, Generation Engineering, Fuels, Load Forecasting, Financial Planning, Regulation, Government Affairs, Distribution and Transmission Engineering, and Wholesale Marketing and Sales. These departments confer with other departments in the company when they need additional information. Key people from these departments meet regularly in an internal RAMPP task force. The task force members discuss work progress, issues, and agenda items for the meetings of the RAMPP Advisory Group (RAG).

Public Advisory Process

The public advisory process mainly occurs through meetings of the RAMPP Advisory Group (RAG). The group includes representatives from public agencies and private organizations. In RAMPP-4 the RAG identified issues, suggested changes or additions to input assumptions, and submitted comments on the draft report. Over several meetings, RAG participants helped develop and modify the RAMPP-4 study plan. PacifiCorp considers the public group's role to be one of providing advice and counsel on the planning process, rather than collaborating for a consensus on the actual plan. Some parties would prefer a collaborative process, and expressed this preference at RAG meetings. However, the company wants its senior management to make resource planning decisions.

PacifiCorp began using a public advisory group during the development of RAMPP-1 (in 1988 and 1989). The company re-convened that group for RAMPP-2 (in 1990, 1991 and 1992), for RAMPP-3 (in 1992, 1993 and 1994), and for RAMPP-4 (in 1994 and 1995). Oregon and Washington public agencies and customer groups began sending representatives during RAMPP-1. Utah public agencies and customer groups began sending representatives to the group during RAMPP-2. Idaho, Montana, and Wyoming agencies began sending representatives during RAMPP-3.

Participants in the RAMPP-4 Advisory Group included public agency staff, private groups, and customer representatives. Following is a list of the groups and individuals represented:

Bonneville Power Administration
California Energy (geothermal developer)
Calpine Energy (geothermal developer)
Chevron (industrial customer)
Community Energy Project (representing residential customers)
Drazen-Brubaker (representing industrial customers)
Exxon
Idaho Public Utilities Commission
Industrial Customers of Northwest Utilities
Kenetech Wind Power (wind developer)
Land and Water Foundation of the Rockies
Montana Department of Natural Resources and Conservation
Montana Public Service Commission
Northwest Natural Gas Company
Northwest Power Planning Council
Paul Olson (representing residential customers)
Oregon Department of Energy
Oregon Public Utilities Commission
OSU Extension Service (representing residential customers)
Portland General Electric
Utah Association of Industrial Energy Users
Utah Committee of Consumer Services
Utah Department of Natural Resources
Utah Division of Public Utilities
Utah Public Service Commission
Washington Office of Attorney General
Washington State Energy Office
Washington Utilities and Transportation Commission
Wyoming Public Service Commission
Zond Wind Power (wind developer)

RAG participants reviewed RAMPP-4 inputs and analyses at 13 all-day meetings and six technical subgroup meetings before the company issued its draft report. The RAMPP-4 process began with three two-day meetings to allow enough time to address issues that arose during RAMPP-3. The company brought in outside speakers with a variety of perspectives. The August 4-5, 1994 meetings focused on strategic planning and competition. The August 25-26, 1994 meetings focused on DSM and renewables (wind and geothermal). On October 6-7, 1994 the group focused on renewables (solar and issues involving all renewable technologies), externalities, and IRP implementation. In addition to the 13 RAG meetings, the company held five technical subgroup meetings on the afternoon before regular RAG meetings from November 1994 to May 1995. These meetings addressed DSM input assumptions and modeling. PacifiCorp led a tour of its control center and dispatch facilities on the day before the June 23, 1995, RAG meeting. Following is a list of the RAMPP-4 RAG meetings:

August 4, 1994	9:30 am - 3:00 pm	
August 5, 1994	9:30 am - 3:00 pm	
August 25, 1994	9:30 am - 3:00 pm	
August 26, 1994	9:30 am - 3:00 pm	
October 6, 1994	9:30 am - 3:00 pm	
October 7, 1994	9:30 am - 3:00 pm	
November 3, 1994	1:30 pm - 4:00 pm	Technical subgroup
November 4, 1994	9:30 am - 3:00 pm	
December 8, 1994	1:30 pm - 4:00 pm	Technical subgroup
December 9, 1994	9:30 am - 3:00 pm	
February 2, 1995	1:30 pm - 4:00 pm	Technical subgroup
February 3, 1995	9:30 am - 3:00 pm	
March 16, 1995	1:30 pm - 4:00 pm	Technical subgroup
March 17, 1995	9:30 am - 3:00 pm	
May 4, 1995	1:30 pm - 4:00 pm	Technical subgroup
May 5, 1995	9:30 am - 3:00 pm	
June 22, 1995	1:30 pm - 4:30 pm	Visit to Control Center
June 23, 1995	9:30 am - 3:00 pm	
September 22, 1995	9:30 am - 3:00 pm	

Requirements for RAMPP-4 From RAMPP-3 Acknowledgment Reviews

Acknowledgment reviews of RAMPP-3 occurred from May 1994, when the report was issued, through May 1995. Four commissions provided responses to the company in the following order: Oregon, Washington, Utah, and Montana. This discussion describes the specific recommendations from each Commission, and the company's response to each recommendation.

<u>Oregon</u>

Recommendations from the Public Utility Commission of Oregon Order No. 94-206, December 22, 1994:

1) "In future plans the company should explain more clearly and explicitly how the results of its model runs are translated into individual Action Plan items."

Response: Chapter Six identifies the steps PacifiCorp took to develop its RAMPP-4 action plan. It also explains how the company used the modeling results to derive each of the items in the action plan.

2) "The company should not apply a strict cost-effectiveness test to renewable acquisitions, but should include consideration of possible future internalization of externalities, fuel price risk, and the benefits of resource diversity."

Response: PacifiCorp did not apply a strict cost-effectiveness test to renewable acquisitions. The company considered future risk of emission taxes, fuel price risk, and the benefits of resource diversity. However, these other factors would have to be weighted very heavily for renewables to become an attractive choice: renewable capital costs would have to drop by 65 percent for these resources to be cost-effective compared to gas-fired resources.

3) "In RAMPP-4 Pacific should discuss thoroughly the effect of the company's wholesale marketing strategies on its supply-side resource acquisition targets."

Response: The company's overall strategy is to buy low-cost supply-side resources and sell them at a higher price on the wholesale market to reduce total system costs. The company does not acquire supply-side resources simply for wholesale sales; rather, wholesale sales give the company more flexibility in timing its resource acquisitions. For example, if the company has an opportunity to acquire a cost-effective resource sooner than needed to meet retail loads, it can do so and sell any surplus on the wholesale market.

4) "We expect that the RAMPP-4 model will more accurately assess the need for peaking resource additions to meet both winter and summer requirements."

Response: The modeling used in RAMPP-3 recognized only winter peaking requirements. The model vendors changed the code for RAMPP-4 so that the model could recognize both winter and summer peaking requirements.

5) "Pacific and its advisory group should explicitly and thoroughly evaluate hookup fees early in RAMPP-4 and include its conclusions in the RAMPP-4 report."

Response: Charging a fee to new customers would have little or no impact on the modeling results. An unreasonably high hookup fee would cause some price-sensitive customers to self-generate or meet their energy needs in other ways that would reduce the company's load growth. RAMPP-4 includes a case with reduced load growth. That case incorporated the probable impact of a hookup fee.

Changes Agreed to by PacifiCorp, from the Public Utilities Commission of Oregon Staff Final Recommendation (incorporated by reference in the Order discussed above):

1) Staff recommendation #4: "Provide evaluation and siting studies for new clean coal technologies such as gasification early in RAMPP-4."

Response: The company conducted an in-depth study on clean coal technologies, especially integrated gasification combined cycle (IGCC), and presented the study to the advisory group in December 1994. Because RAMPP-4 shows that gas-fired resources are now more cost-effective than coal-fired resources, the company has not pursued coal plant siting studies other than evaluating Hunter 4 as a potential site for a new coal-fired plant.

2) Staff recommendation #9: "Include in the RAMPP-4 report a discussion of the status of any ongoing and prospective resource acquisitions, including any potential contingencies such as litigation, delays, fuel supply problems, etc. The report should also discuss existing or pending legislation that may impact system planning."

Response: The company is involved in current discussions or negotiations with developers on several projects: the RFP, QF developers and independent developers.

PacifiCorp issued an RFP in December 1994 and received bids in April. Follow-up information from the top two candidates shows that only one bid is lower than avoided cost prices. The company is proceeding with a more detailed financial analysis and comparison of the top bid with other, non-RFP options available. The next step is further discussions with the lowest bidder, but only if the project compares favorably in light of all market conditions.

PacifiCorp is in discussions with several QF and other independent developers. At any point in time, the company is reviewing proposals from several developers. This process typically involves seeking additional information from the more developed proposals.

In addition, the company briefs the RAG when it is considering resource acquisitions. Examples include PacifiCorp Senior Vice President Dennis Steinberg's briefing on Hermiston and Principal Engineer Jim Lacey's briefing on turbine upgrades.

3) Staff recommendation #10: "Explore whether the Integrated Planning Model (IPM) can be improved to optimize for DSR acquisition levels and timing."

Response: The modeling in RAMPP-4 allowed the model to select the amount and timing of DSM; thus it optimized for DSM acquisition levels and timing.

4) Staff recommendation #11: "Resolve model discrepancies early in RAMPP-4, such as occurred in the model results for certain accelerated and high DSR cases in RAMPP-3."

Response: The company has not found any model discrepancies in RAMPP-4.

5) Staff recommendation #12: "Incorporate the results of the UM-551 cost effectiveness docket in RAMPP-4, both in the determination of cost effectiveness limits and in the development of measure and program costs."

Response: The company used UM-551 standards in developing its cost-effectiveness criteria for use in RAMPP-4.

6) Staff recommendation #13: "Pacific should provide the Commission a report assessing fuel switching."

Response: The company provided a fuel switching report to the Commission in April 1995.

<u>Washington</u>

Recommendations from Washington Utilities and Transportation Commission letter in Docket No. UE-940500, February 15, 1995:

1) "RAMPP-4 should include more integration of transmission planning with resource planning."

Response: RAMPP-4 has integrated transmission planning with the resource selection process in six ways: (1) It identifies loads and resources by geographic area that reflects the company's existing transmission paths and constraints among those specific geographic areas. (2) The model inputs reflect how transmission capacities vary by season and time of day. (3) The model inputs include nomograms (simultaneous transfer limitations on two transmission paths) that link more than two geographic areas. (4) All supply-side resource costs include the costs to interconnect the new resource to the backbone transmission system. These costs vary by resource and by geographic area. (5) Two sensitivities in RAMPP-4 increased the capacities of two key transmission paths to determine whether greater capacity on those lines would affect resource choices. (6) The model can choose to "move" a resource from one geographic area to another, at a cost. This frees up space on that transmission path. One of the RAMPP-4 sensitivities altered the cost of the geographic conversion in two geographic areas so that the model selected this option.

In addition, the company is carefully monitoring the FERC Notice of Proposed Rulemaking (NOPR) and FERC's intent to achieve comparability of transmission costs and services for all users of the transmission lines. As PacifiCorp better understands the implications of these marketplace changes, the RAMPP-5 process can incorporate them.

2) "RAMPP-4 should further refine consideration of environmental impacts and avoid misinterpreting such impacts when using comparative scenario analyses."

Response: RAMPP-4 included three sensitivity cases using environmental adders. The company was careful in comparing results from those cases to avoid any double counting or misinterpretation.

3) "RAMPP-4 should use a supply curve analysis for coal fuel supply costs that recognizes the relationship between demand and price."

Response: RAMPP-4 used a supply curve analysis for coal fuel supply costs.

4) "RAMPP-4 should include an in-depth and detailed analysis of integrated gasification combined cycle technology."

Response: The company conducted a detailed analysis of integrated gasification combined cycle technology in 1994. The company presented that report to the advisory group in December 1994.

5) "RAMPP-4 should modify the modeling procedures to recognize the practical size of resource and consider the full range of direct and opportunity costs associated with resource 'lumps' and the timing of their acquisition."

Response: The model code does not allow the addition of selected resources in 'lumps.' However, to respond to this request, one of the sensitivities in RAMPP-4 forced company-identified resource additions to occur in "lumpy" sizes.

6) "RAMPP-4 should address the positioning and framework under which the company could take advantage of wholesale opportunities to lower cost for itself and its ratepayers."

Response: All of the base and sensitivity cases included assumptions about the wholesale market, including sensitivities that altered the assumed price of non-firm power on the wholesale market. These cases provided information about the impact of the wholesale market on retail customer prices.

7) "RAMPP-4 should clarify the relationship between the resource planning process and corporate decision making and objectives."

Response: The RAMPP-4 report includes a section on the company's perception of the future, which affects both corporate decision making and resource planning. Corporate decision making for resource acquisitions, whether they are owned resources or purchased power, begins with a review of needs as identified in RAMPP. Based on needs as identified in the most recent RAMPP action plan, the company reviews opportunities as they occur. That review first confirms that the opportunity is consistent with the RAMPP action plan; then the company compares the cost of an opportunity with the cost of similar resources in the last RAMPP analysis, with the most recent avoided costs, and with other opportunities then available.

8) "RAMPP-4 should include a demonstration that clearly shows that the action plan is supported by the extensive resource analyses performed."

Response: Chapter 6 identifies the steps the company used to develop its action plan, and how each of the items in the action plan relates to the modeling results.

9) "RAMPP-4 should include a demonstration that clearly shows that consideration of identified costs and risks are equitably evaluated from the joint perspective of the utility and its ratepayers."

Response: PacifiCorp first considers the impact of any resource decision on retail prices. The company also considers the impact on earnings. The balancing of these concerns occurs as management makes its decisions on the action plan and on any investment decision. The action plan for RAMPP-4 did not require a trade-off between price and earnings impacts, which can occur with decisions about DSM levels in the action plan. The selected amount of DSM came from a case that lowered DSM costs by 15 percent to reflect the regional credit and a 5 percent credit for avoided transmission and distribution investments. This level of DSM caused no more price impact than the base case amount that used actual DSM costs.

Utah

Recommendations from Utah Public Service Commission Order in Docket No. 94-2035-05, March 7, 1995:

1) "RAMPP-4 should include sensitivity analysis for critical assumptions."

Response: RAMPP-4 included cases that tested critical assumptions on load growth, gas prices, external costs and non-firm wholesale prices.

2) "RAMPP-4 should include transparency between model results and action plan."

Response: Chapter Six identifies the steps the company used to develop its action plan, and how each of the three key items in the action plan relate to the modeling results.

3) "RAMPP-4 should integrate results of transmission studies using GE MAPS and Multisym into the IRP process."

Response: Multisym is a production costing model, not a resource selection model. Therefore, Multisym's utility for RAMPP planning is limited to benchmarking studies. Before RAMPP-4 modeling began, the company conducted studies to compare RAMPP results to Multisym results. Both models use very similar data inputs, and the company updates those inputs for both models simultaneously. These studies allowed the analysts to identify data inconsistencies and problems, and correct them before RAMPP-4 modeling began. GE MAPS data development has never been completed; therefore there are no formal studies to use for comparison. When MAPS studies are complete, the company will use them for comparison and benchmarking with RAMPP modeling.

4) "RAMPP-4 should provide a suitable risk analysis to better explain why the action plan differs from least cost principles and to quantify the benefits and costs of such deviation."

Response: The RAMPP-4 action plan follows least cost principles. PacifiCorp's management adopted action plan targets that are consistent with model selections based on least cost principles. In addition, the Results Chapter contains a risk analysis section addressing risks to customer prices.

5) "RAMPP-4 should investigate the 'growth is good' conclusion of RAMPP-3, run the cases necessary to substantiate and evaluate this conclusion."

Response: The RAMPP-4 analyses confirmed that higher levels of load growth do not lead to higher customer prices. The company does not interpret this as "growth is good;" i.e., that the company should pursue higher load growth because it leads to lower customer prices. Instead, the company believes the results indicate that higher levels of load growth can be managed without causing higher customer prices.

6) "RAMPP-4 should include an independent review of the IPM model."

Response: Resource Management International (RMI) conducted an independent review of the IPM model. RMI presented that study to the public advisory group in December 1994.

7) "RAMPP-4 should review assumptions regarding the wholesale markets, test the sensitivity of least cost outcomes to these assumptions."

Response: RAMPP-4 included sensitivity cases to test alternative levels of non-firm prices on the wholesale market. The study plan included non-firm price sensitivities for the base case, for cases that added new resources to the system too early (overbuilding cases), and for cases that did not add resources when needed (underbuilding cases).

8) "RAMPP-4 should analyze potential impacts on the IRP process brought about by a competitive restructuring of the electric industry."

Response: If competition increases PacifiCorp's customer base, the results would be similar to the medium-high load growth case included in RAMPP-4. If competition decreases PacifiCorp's customer base, the results would be similar to the medium-low load growth case included in RAMPP-4. In addition, the model inputs incorporated lower non-firm energy prices that have resulted from increased competition.

Montana

Recommendations from Montana Public Service Commission Order in Docket No. 94.4.19, Order No. 5839, May 5, 1995

1) "RAMPP-4 should correct the RAMPP-3 deficiency: the plan acquires demand-side resources based, in part, on consideration of lost revenues."

Response: Consideration of lost revenues did not affect the amount of DSM in the RAMPP-4 action plan.

2) "RAMPP-4 should correct the RAMPP-3 deficiency: the plan purportedly focuses on acquiring resources in a manner which limits rate impacts rather than in a manner which minimizes total costs."

Response: Consideration of rate impacts did not alter the amount of DSM in the RAMPP-4 action plan.

3) "RAMPP-4 should correct the RAMPP-3 deficiency: the company acquires significant resources without subjecting those resources to the full measure of RAMPP-3 analyses."

Response: It is not true that the company acquires significant resources without subjecting those resources to the full measure of RAMPP-3 analyses. All of the company's resource acquisitions since 1992 have been consistent with the relevant RAMPP action plans. Chapter 5 begins with a discussion of this issue. For example, if the action plan calls for acquisition of peaking resources, the company may acquire those resources through a purchase power contract. If the purchased power price is lower than the price anticipated in the RAMPP analyses, the company believes that is consistent with the action plan.

4) "RAMPP-4 should correct the RAMPP-3 deficiency: the plan inadequately documents the criteria and judgment used by management in developing the action plan and inadequately links the transition from RAMPP-3 to the action plan."

Response: Chapter 6 identifies the steps the company used to develop its action plan, and how each of the three key items in the action plan relates to the modeling results.

5) "RAMPP-4 should correct the RAMPP-3 deficiency: the plan inadequately incorporates transmission costs as they relate to evaluating alternative resource options."

Response: RAMPP-4 has integrated transmission planning with the resource selection process in six ways: (1) It identifies loads and resources by geographic area that reflects the company's existing transmission paths and constraints among those specific geographic areas. (2) The model inputs reflect how transmission capacities vary by season and time of day. (3) The model inputs include nomograms (simultaneous transfer limitations on two transmission paths) that link more than two geographic areas. (4) All supply-side resource costs include the costs to interconnect the new resource to the backbone transmission system. These costs vary by resource and by geographic area. (5) Two sensitivities in RAMPP-4 increased the capacities of two key transmission paths to determine whether greater capacity on those lines would affect resource choices. (6) The model can choose to "move" a resource from one geographic area to another, at a cost. This frees up space on that transmission path. One of the RAMPP-4 sensitivities alters the cost of resources in two key geographic areas so that the model selects this option.

In addition, the company is carefully monitoring the FERC Notice of Proposed Rulemaking (NOPR) and FERC's intent to achieve comparability of transmission costs and services for all users of the transmission lines. Comparability means outside utilities would receive the same terms and services as the utility that owns the lines. As PacifiCorp better understands the implications of these marketplace changes, the company will incorporate them into RAMPP-5.

Evolution of the IRP Process

Integrated Resource Planning will evolve as the industry changes. IRP under state regulatory commission oversight is consistent with a monopolistic industry; however, it is not consistent with a competitive one. As the electric utility industry evolves to a more competitive marketplace, the need for planning under commission oversight decreases. In a competitive environment, the market acts as an oversight agency, assuring that those who plan effectively and meet customer needs get to stay in the game. Others do not survive the competitive arena.

PacifiCorp anticipates that IRP could change in several ways. First, IRP makes sense for the non-competitive, regulated part of the business (retail customers who do not have competitive choices), but not for the competitive part (retail customers who do have competitive choices, and wholesale customers). However, the way in which IRP could change depends partly on how much of the business remains subject to regulation. IRP can be tailored to the segment of the business that remains regulated.

For example, if extensive restructuring occurs and retail customers have access to competitive suppliers, or if the industry or a company is functionally disaggregated (with generation, transmission and distribution becoming separate businesses), then IRP can focus on the need to provide retail service efficiently and at low cost to the utility's non-competitive customers. IRP would review the balance between demand-side and supply-side services, the balance between short-term and long-term agreements with its suppliers, the balance between peaking and baseload contracts, and the balance between price impacts and benefits.

PacifiCorp believes the meaning of the term "least cost" should be broader to reflect changing market realities. The interpretation of least cost by state utility commissions has led to an expectation that the utility will plan primarily for lowest total resource cost (TRC). TRC includes utility cost, customer costs for DSM, and non-energy benefits of DSM. Using a TRC standard for planning leads to higher levels of DSM and higher customer prices than a focus on utility costs and retail prices. Focusing on TRC does not adequately reflect the reality of customer choice in a competitive marketplace. Customers make their decisions based on perceived costs and benefits to their own lives and businesses. Broadening the definition of "least cost" to incorporate customers' price concerns will increase the usefulness of IRP to both the utility and regulators. IRP needs the flexibility to consider other measures that may, in the future, reflect the marketplace.

Similarly, focusing on average customer bills does not adequately reflect the reality of customer choice. Although DSM activity may lower average customer bills, non-participating customers may see no benefit. In fact, their bills may go up. Non-participating customers may have made their energy use efficient several years ago. DSM may be a service that customers value, but that value is most apparent in the year in which it actually reduces a customer's bills. At that point, the only way to further reduce their bills is through lower prices.

Increasing competition will create a need to keep competitive information confidential. The IRP process currently requires open disclosure of company plans and strategies. In a competitive market, some of this information must remain confidential. As competition increases, IRP requirements will need to balance the need for adequate regulatory review of company resource planning with the utilities' need to keep proprietary information confidential. The company has not determined how best to handle this issue.

PacifiCorp would like to help make the IRP process less static. One way is to focus on a shorter time horizon and a greater recognition of the increasing importance of short-term conditions. Current IRP assumes that existing customers will remain on the regulated utility's system for 10 and 20 years. Assuming customers stay on the system, the higher initial prices caused by DSM and the system investment in DSM will be balanced by benefits that occur 10 and 20 years out. However, in a competitive marketplace, customers may not stay on the utility's system that long; thus, the system may never receive those long-term benefits.

Another way to make the IRP process less static is to incorporate more flexibility in IRP action plans. When utilities built and owned their own power plants with long lead times, they could evaluate those acquisitions years ahead of decision-making. Now utilities rely on resource availability in a fast-changing, open market with very short lead times. Utilities cannot commit to specific resource decisions years ahead of need, because future opportunities are both uncertain and ever-changing. Action plans should use language that identifies a need, such as a range of baseload requirements over a specified time period. It should then be the responsibility of the utility to evaluate specific opportunities as they arise and explain any decisions to its public advisory group on a timely basis.

PacifiCorp believes that a comprehensive discussion of these issues will help all of the affected parties arrive at solutions that will enable

IRP to be increasingly useful to both utilities and their regulators. At this time, the company is not recommending that the IRP codes, standards, and rules be changed in each state. The issues raised above are issues of transition. When and if regulation and company structure change, the issues will also change. As the industry changes, the company anticipates that IRP will evolve to meet the changing needs of regulators, customers, and the utilities.

Chapter 3: Input Update

PacifiCorp has a number of resource alternatives for meeting future electricity needs. They include the existing system, new demand-side alternatives, and new supply-side resources. This chapter describes these alternatives. It discusses the fuel cost assumptions that are a key part of the total cost of new supply-side resources.

The company made two significant, and other less significant, modeling changes for RAMPP-4 and updated all of the major modeling input assumptions. The inputs included system transmission constraints; load forecasts; the existing system, including firm purchases and sales; gas prices; coal prices; new resource costs for both the demand-side and supply-side; transmission system costs; reserve margin requirements; the discount rate and inflation. The chapter concludes with a section that identifies the changes that have occurred in inputs since the company finalized the modeling inputs in early 1995.

The Model

The Integrated Planning Model (IPM) is a capacity expansion, linear programming model that minimizes the present value of total resource costs. The results from IPM then pass to the financial model, which calculates total resource cost and its average levelized mills/kWh, and total utility cost and its average levelized mills/kWh. The modeling uses a 20-year planning horizon. However, the model incorporates the impact of end effects when selecting new resources because each case includes an additional 30 years to recognize the financial benefits of investments made in the last few years of the planning period.

To keep model run times manageable, the company required the model to select new resources for only 14 of the years in the 50-year period. Those 14 years were: each year for the first eight years (1996 through 2003), and the years 2005, 2008, 2011, 2015, 2024, and 2038. However, the model calculated utility costs for every calendar year, using the resource choices from the nearest selection year to calculate production costs.

Model Changes Since RAMPP-3

PacifiCorp acquired the rights to use the IPM model from ICF Resources, Inc. for RAMPP-3, and continued that licensing agreement for RAMPP-4. During both planning cycles ICF Resources made code changes to improve the model's ability to reflect PacifiCorp's system. PacifiCorp made two major and several minor modeling changes for RAMPP-4. The list below identifies all of the changes made in the IPM model itself and in the company's treatment of various modeling issues. The discussion following describes the two major changes, listed first.

- The model can recognize both winter and summer peak requirements. In RAMPP-3 the model could recognize only winter peak requirements.

- The model can select the amount of DSM that is optimal for each case. In RAMPP-4 the model did not select the amount of DSM that was optimal for each case.

- The model can dispatch down existing coal plants to zero capacity. In RAMPP-3 the model could only dispatch them down to 40 percent or more of their capacity (depending on the particular coal plant).

- ICF corrected problems with the objective functions that were identified in RAMPP-3.

- ICF corrected some small errors occurring in the calculation of total costs for non-firm purchases and sales in non-run years.

- For the first time in RAMPP-4, PacifiCorp used the plant geographic conversion code to test the cost-effectiveness of adding new transmission capacity. This is case #57.

- PacifiCorp offered the Gadsby conversion option to the model in RAMPP-4. This is part of the portfolio, discussed in the previous chapter. It was not part of the portfolio in RAMPP-3.

- Three cases tested alternative treatments of end effects in the model. These are cases #65, #66 and #67. RAMPP-3 did not include cases that tested alternative treatments of end effects.

- The treatment of wind resources was changed in RAMPP-4. The following discussion explains these changes.

The primary change for modeling in RAMPP-4 was the addition of a summer peaking requirement. In RAMPP-3 the model added resources to meet a reserve requirement for the winter peak. In RAMPP-4 the model added resources if the system (including the existing system and new resources added to that point) was insufficient to meet the reserve requirement in either the winter or summer season. Although PacifiCorp's winter peak for the retail load remains higher, the summer peak dominates resource needs because the system has more winter-peaking resources. This is not a matter of retail load versus wholesale load. The winter peak of retail load becomes a summer peaking need only if both wholesale sales and wholesale purchases are considered. The company has significant wholesale winter peak purchases that help meet the winter peak need. The company does not have a comparable amount of summer peak purchases to meet the summer peak need. Thus, in the modeling, summer peak needs drove resource additions.

The other major modeling change implemented for RAMPP-4 is the way of offering DSM resources to the model, and the way the model selects new DSM resources. RAMPP-3 hard-wired the amount of DSM for each case (i.e., the model did not select the amount of DSM). In RAMPP-4 the model <u>did</u> select the amount of DSM in each case. This approach provided more information on the amount of DSM that was cost effective under various assumptions.

RAMPP-4 divided each DSM program into bundles of measures, grouped by cost. Each program had from one to four bundles. The model could select the bundles one at a time, moving from the lowest cost to the higher cost bundles, and stopping when it reached a more expensive bundle that was not a cost effective choice. Previously the company has dealt with DSM on a program-by-program basis, so that the entire program had to be cost effective. The bundle approach allows for selection of only those groups of measures within each program that are cost effective.

RAMPP-3 modeled wind using IPM's hydro modeling techniques in order to circumvent a computer code problem. The model vendors corrected the computer code problem before RAMPP-4 began, allowing the company to model wind as a renewable resource in RAMPP-4.

Major Input Assumption Changes Since RAMPP-3

Following are the major changes in input assumptions for RAMPP-4, with references to the sections in this chapter where they are discussed. Other changes merely involved updating data (such as the details of supply-side costs) which had no significant effect on the results.

- RAMPP-4 included updated assumptions about some of the transmission limits between geographic areas. See "Geographic Areas and Transmission Limits."

- The new load forecasts for RAMPP-4 tended to be lower than RAMPP-3, primarily in Wyoming. The other areas showed little change since RAMPP-3. See "Load Forecasts."

- RAMPP-4 analyzed three load forecasts instead of five, as in RAMPP-3. See "Load Forecasts."

- Lower native load resulted from the sale of PacifiCorp's Northern Idaho service territory. See "Load Forecasts."

- In RAMPP-4, Hermiston was part of the existing system for all of the cases; in RAMPP-3 it was in only one sensitivity. See "Existing System."

- Turbine upgrades at some of the existing coal-fired units will increase system capacity by about 150 MW. RAMPP-3 did not include the turbine upgrades. See "Existing System."

- Updated firm wholesale contracts altered the existing system slightly. See "Existing System."

- The updated gas price and escalation rates in RAMPP-4 were lower than the gas assumptions used in RAMPP-3. See "Gas Prices."

- A supply curve provided three different levels of costs for new coal-fired resources in Utah. RAMPP-3 included a second coal price as a sensitivity. See "Coal Prices."

- RAMPP-3 used costs for a new coal-fired plant in Utah that were an average of costs for a new unit at Hunter and a new unit at a generic site. RAMPP-4 specified costs for Hunter separately. See "Supply-Side Resources."

- RAMPP-4 included a summer peak purchase option through 2002. RAMPP-3 included no purchases in the portfolio. See "Supply-Side Resources."

- RAMPP-4 included separate wind resource costs for firm and non-firm power. RAMPP-3 did not break out wind resources by firm and non-firm. See "Supply-Side Resources."

- The total amount of wind resource available was less for RAMPP-4 than it was for RAMPP-3. See "Supply-Side Resources."

- RAMPP-4 included another peaking option -- compressed air storage that was not part of the RAMPP-3 portfolio. See "Supply-Side Resources."

- For RAMPP-4, the transmission costs for connecting each potential new resource to the local grid better reflect preferences to minimize costs for resource location. See "Transmission Costs."

- RAMPP-4 had lower non-firm market prices than did RAMPP-3 and no geographic price differences in the non-firm market prices whereas RAMPP-3 included geographic price differences in non-firm prices. See "Non-firm Prices."

- The association between non-firm market prices and gas prices was an 80 percent correlation in RAMPP-4 instead of a 100 percent correlation in RAMPP-3. See "Non-firm Prices."

- RAMPP-4 included larger potential non-firm purchase capacities than RAMPP-3, reflecting greater market competition. There was no change to potential non-firm sales capacities. See "Non-firm Prices."

- The planning reserve margin used in RAMPP-3 was 15 percent; the company lowered it to 12 percent in RAMPP-4. See "Reserve Requirements."

- RAMPP-4 used a slightly lower cost of capital than RAMPP-3 and a slightly lower inflation rate.

- RAMPP-4 included no solar resources in the portfolio because RAMPP-3 showed that their costs were too high for them to be selected under any of the sensitivities.

Geographic Areas and Transmission Limits

PacifiCorp has enough transmission capacity in each geographic area it serves to meet local load requirements. However, transmission constraints limit the transfer of power between areas. The constraints are particularly evident between the western and eastern parts of PacifiCorp's system. The model used in RAMPP-4 respects these transmission constraints between geographic areas. It dispatches new and existing resources and adds additional generating resources so that power flows between areas stay within these limits.

In time there will be a need for transmission improvements within each of the load areas; however, those improvements will be of smaller sizes and costs. The financial model included in its five-year plan of costs an amount that covers these smaller transmission and sub-transmission investments. The model does not assume that the company will invest in major transmission investments that add to the transfer capability between areas.

The model first looks to existing resources within a geographic area to meet load needs, then available resources from other areas that can move over the existing transmission network. It then adds resources in a manner that respects the transfer limits. Since the Integrated Planning Model (IPM) is a linear programming model, it looks at all of these factors, and all of the inputs, simultaneously. For example, if the system needs more resources for the Oregon-Washington-California (OWC) area, and the transmission paths from other areas into OWC are being fully used already, it will add resources in the OWC area, even if less expensive resources are available in another area.

Map 3-1 shows the geographic areas used in the modeling process. It includes three load and resource areas (OWC -- Oregon, Washington, and California; UTA -- Utah; and WYO -- Wyoming). The OWC area includes loads in Oregon, Washington, Montana and California and the following resources: the Centralia and Colstrip coal-fired plants, the Hermiston and James River cogeneration plants, the PacifiCorp and mid-Columbia hydro resources, the BPA peaking contract, and other purchased power contracts. UTA includes loads in Utah, southern Idaho and southwestern Wyoming, and these resources: the Carbon, Huntington, Hunter and Naughton coal-fired plants; the Blundell geothermal plant; the Gadsby gas-fired plant; the Little Mountain Cogeneration plant; Utah hydro; and purchased power contracts. The WYO area includes loads in the eastern Wyoming service area, the Dave Johnston and Wyodak coal-fired plants and some purchased power.

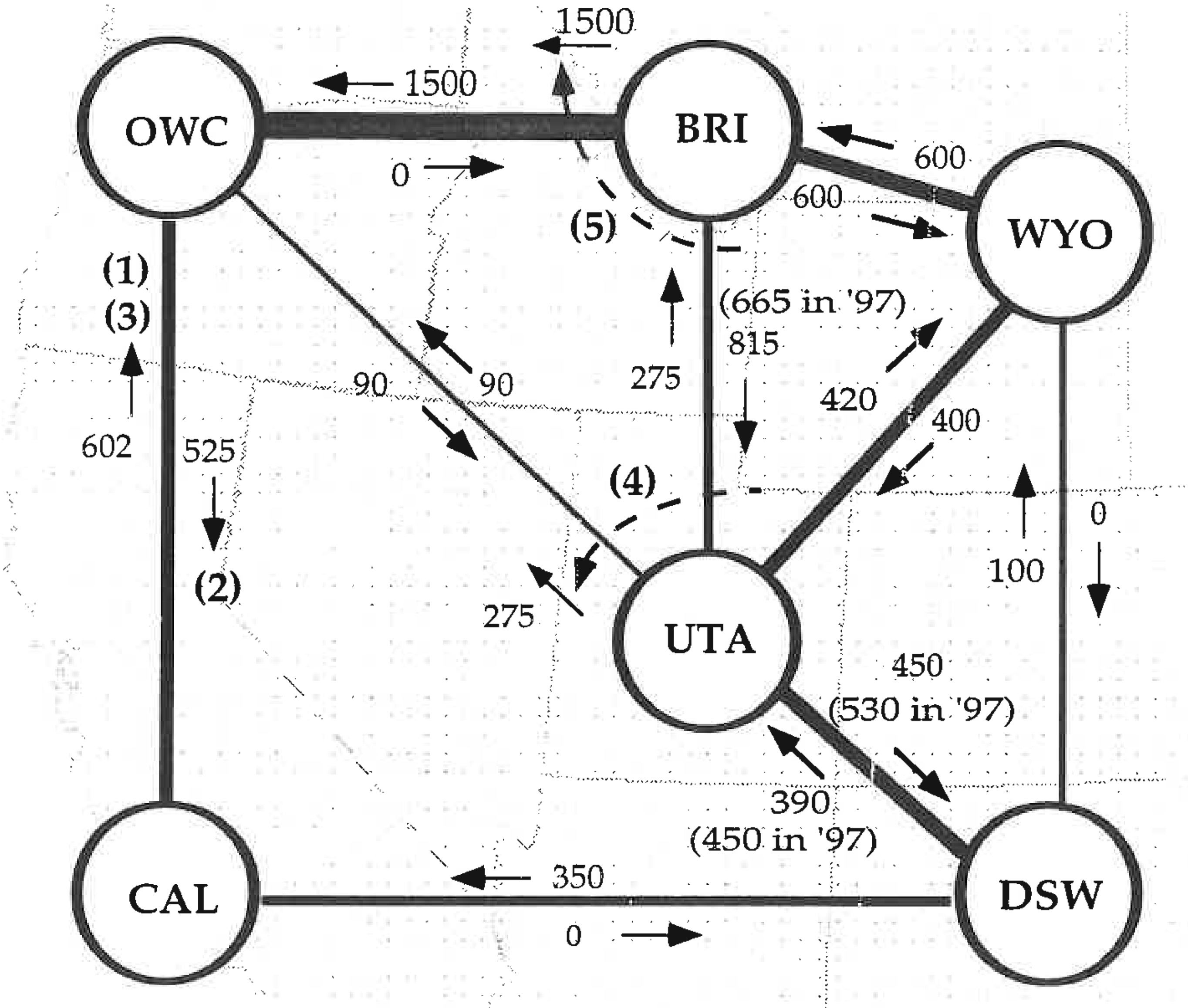
The three other geographic areas are Bridger (BRI), which is a resource-only area; Desert Southwest (DSW), another resource area; and California (CAL), a market-driven area that offers opportunities to both buy and sell power.

BRI includes the Jim Bridger coal-fired plant. The model recognizes that the plant's location and nearby transmission connections with Idaho Power impose constraints on the system. In the DSW and CAL areas, the model considers how the company buys and sells secondary non-firm power to minimize costs. DSW includes the Cholla, Craig and Hayden thermal plants and power sales contracts in the Desert Southwest, including the Colorado market. CAL represents the purchase and sale of power between PacifiCorp and California and Nevada utilities.

Map 3-1 shows the transmission paths among the six regions. Transfer constraints involve either the official published transfer capabilities recognized by the Western System Coordinating Council (WSCC), or the level of contract rights PacifiCorp has secured from other utilities. For each transmission path, the map shows the transfer constraints in both directions. The constraints differ by direction because of their

Geographic Areas and Transfer Capabilities (MW)

Map 3-1



Transfer Capabilities (MW) are Pacificorp's inter-regional winter transfer capabilities utilized for RAMPP-4 Studies.

(1) 602 MW modeled as 260MW off-peak capability in selected studies.
(2) Subject to change depending on final Non-Federal-Participation allocation or long term contract discussions.
(3) Subject to change depending on final South to North Pacific Intertie rating.
(4) In studies, the combined flow of the UTA to BRI and the UTA to OWC paths is limited to the capability of the UTA to BRI path.
(5) In studies, the combined flow of the BRI to UTA and the BRI to OWC paths is limited to the capability of the BRI to OWC path.

placement relative to the movement of power on other paths in the grid, and the location of loads along the paths. Usually a path with a large load at the sending end has a larger capability than one with a large load at the receiving end. The map may be confusing in this regard, because the capabilities shown are only PacifiCorp's contract rights and do not reflect total path capability.

The primary transmission changes for RAMPP-4 included modified path limits for four paths. The BRI to UTA path was 815 MW in RAMPP-3; in RAMPP-4 it was changed to 665 MW in 1997. The decrease is due to a new 150 MW wheeling contract with Arizona Public Service. This change may force a corresponding decrease in non-firm wholesale business. The UTA to DSW path decreased from 720 MW in 1996 in RAMPP-3 to 530 MW in 1997 in RAMPP-4. The decrease is due to the new 150 MW wheeling contract with Arizona Public Service and a 40 MW re-rating of the entire path capability. The date of the change in the path rating increase from 1996 to 1997 represents a new probable completion date for the Glen Canyon/Navajo integration project. In RAMPP-3, the DSW to UTA path was 425 MW; in RAMPP-4 it was reduced to 390 MW in 1996 due to a 35 MW contract with UAMPS. The CAL to OWC path was 525 MW in RAMPP-3; it increased to 602 MW in RAMPP-4. The increase resulted from an agreement with the Bonneville Power Administration (BPA) that allowed PacifiCorp to increase its share of the line. This change will allow the company to increase its non-firm wholesale business by the same amount where cost-effective.

390?

Load Forecasts

The first step in the RAMPP planning cycle is the load forecasts. The RAMPP-4 forecasts needed to cover the period 1996-2015. In order to efficiently produce the RAMPP-4 forecasts, the company started with the RAMPP-3 forecasts rather than with basic economic and demographic data. The company also decided to analyze only three forecasts in RAMPP-4 -- the medium-low, medium, and medium-high -- rather than five load forecasts as in RAMPP-3. RAMPP-3 showed that the low forecast required no new resources in the first 10 years of the planning period, and nothing has occurred that would change that result. RAMPP-3 also showed that the high load forecast required the same pattern of resource additions as the medium-high forecast, only sooner. Again, nothing has occurred to change that pattern. Therefore, the company decided that three load forecasts would be sufficient for RAMPP-4. PacifiCorp completed the RAMPP-3 load forecasts in the fall of 1993, just one year before beginning work on the RAMPP-4 forecasts.

PacifiCorp first developed a baseline forecast for RAMPP-4 and compared it to the RAMPP-3 medium forecast. The baseline included the company's 1993 temperature adjusted sales, nine months of historic temperature-adjusted data for 1994, and the company's most recent forecast for 1995 and 1996. For the total company, the baseline varies only slightly from the RAMPP-3 medium forecast for most of the years in the 20-year planning period. The baseline was slightly less than the RAMPP-3 medium forecast in 1995 and 1996. However there are some differences for certain geographic areas, which required additional analysis.

Slight differences from the medium forecast would not be unusual and would not warrant a major revision in the forecast. The Montana baseline for RAMPP-4 tracked closely with the RAMPP-3 medium forecast. The Oregon, California and Utah baselines for RAMPP-4 fell between the RAMPP-3 medium-low and medium-high forecasts. The Washington and southern Idaho baseline forecasts were only slightly outside the range of the RAMPP-3 medium-low and medium-high forecasts. This was partly because Southern Idaho had abnormally high irrigation sales in 1994. In eastern and western Wyoming the RAMPP-4 baselines were significantly different from the RAMPP-3 medium forecast. In western Wyoming, the "blow-down" (reduction in planned operations) at the natural gas fields occurred earlier than forecasted in RAMPP-3, resulting in lower loads there. At the same time, growth in the industrial sector in eastern Wyoming has been slower than expected.

The company considered three alternative ways to update the forecasts:

1) Update the load forecasts for eastern and western Wyoming only.

2) Update the load forecasts for eastern and western Wyoming, as well as Washington and Idaho

3) Update the load forecasts for all areas except Montana.

None of the approaches called for updating the Montana load forecast, because the baseline in Montana tracked so closely with the medium RAMPP-3 forecast.

PacifiCorp tested each of these approaches. First, the company applied the RAMPP-3 medium case growth rates to the 1996 baseline forecast to develop a new medium forecast for RAMPP-4. The next step was to apply the spread between the RAMPP-3 medium forecast and the RAMPP-3 medium-low forecast to the new RAMPP-4 medium forecast. This developed a new RAMPP-4 medium-low forecast. The company used the same process to develop a new RAMPP-4 medium-high forecast. In western Wyoming, the earlier-than-expected blow-down made this methodology inadequate. Load changes in that area required new forecasts.

Since RAMPP-4 was to be an update to RAMPP-3, the company decided that it needed to identify where conditions had changed significantly in ways that would change forecast conditions. First the company reviewed the forecast with actual conditions to that point in time, and to changes in the outlook for the future that were then apparent. That review was presented at an early public advisory group meeting. However to further review the impact of selecting one alternative over another, the company also determined what the three different methods would forecast for the year 2013. Table 3-2 shows the results of this review. The difference in the forecasted value between RAMPP-3 and RAMPP-4 for the same load growth level was very small, especially considering the overall range covered by all the forecasts scenarios. Since all three ways of updating the forecasts produced nearly identical results, the company chose to use the one ~~that would require the least resources~~: alternative 1. This was the ~~fastest method~~ in the middle and would supply results quicker; this would allow all parties more time to review the modeling results and develop the action plan. Performing the additional work necessary for the other alternatives would not have made a significant difference in the forecasts.

'90. change?

The company did not seriously consider the alternative of developing completely new forecasts. The time available under the RAMPP-4 schedule did not allow it. And, a review of economic conditions and forecast performance indicated that performing the work necessary to develop completely new forecasts would not result in significantly different forecast growth rates for RAMPP-4. The company included in

Difference between the RAMPP-3 Medium Forecast and Three Alternative RAMPP-4 Forecasts in (2013) in MWa

Table 3-2

	Alternative 1: Update Eastern and Western Wyoming Only	Alternative 2: Update Eastern and Western Wyoming, Washington & Idaho	Alternative 3: Update all areas except Montana
	Rampp-3 had this		
Medium High	much higher 201	217	160
Medium	resource 149	163	115
Medium Low	require 129	141	102

Lowest
R-4
forecast

its updating process the significant changes that would have made any difference in a new forecast. Those changes occurred in Wyoming.

Therefore, the RAMPP-4 forecasts use the RAMPP-3 forecasts for Oregon, Washington, Montana, California, southern Idaho, and Utah. The RAMPP-4 forecasts, however, used lower forecasts for eastern and western Wyoming. Since the RAMPP-3 forecasts only went to 2013, and RAMPP-4 extends to 2015, the company extrapolated the RAMPP-3 forecasts for two years to 2015.

The relationship between sales, energy (including losses) and peaks calculated in RAMPP-3 remained the same for RAMPP-4. The company modified the final load forecasts for three other changes.

1) DSM implemented in 1994 and 1995 lowered the load forecast for 1996, the first forecast year for RAMPP-4. The company subtracted the amount of DSM expected by the end of 1995 from each of the RAMPP-4 load forecasts.

2) The company sold its northern Idaho distribution assets and service territory in 1995 to The Washington Water Power (TWWP). The sale lowered the total company load by 55 MW and the company's total number of customers by 9,800. PacifiCorp has no generating resources in northern Idaho, nor does it have any direct transmission access. It had been buying power to serve the load from WWP. PacifiCorp was anticipating significant future price increases due to erosion of the BPA residential exchange credit and higher wheeling costs. These price increases would jeopardize PacifiCorp's commitment to providing superior value to shareholders by being a low-cost producer. Therefore, the company decided to sell its northern Idaho service area.

3) RAMPP-3 assumed the company would continue to make retail sales for resale to Cheyenne Light & Power, and Montana-Dakota Utilities (MDU) throughout the forecast period. The company now believes the Cheyenne sale will continue but the MDU sale will end in 1996-97 when the current contract expires.

Difference Between RAMPP-3 and RAMPP-4 Medium Forecasts in MWa

Table 3-3

Year	RAMPP-4	RAMPP-3	Difference	DSM in 94/95	Sale of N. ID Service Area	Loss of Sales to WY Resale	Lower Oil/Gas Loads W. WY	Lower Trona Loads in E. WY
1996	5414	5645	-231	-40	-32	0	-131	-27
2000	5748	6189	-441	-40	-35	-128	-206	-32
2004	6348	6803	-455	-40	-38	-128	-208	-40
2005	6463	6890	-428	-40	-39	-128	-179	-41
2009	7056	7412	-356	-40	-44	-128	-96	-47
2013	7617	7998	-381	-40	-48	-128	-111	-53

Key Forecast Information
Total System

Table 3-4

Forecast	Energy				Winter Peaks				Summer Peaks			
	Avg. Annual Growth Rate %	Total MWa at 2005	Total MWa Added by 2005	Annual Average MWa Added	Avg. Annual Growth Rate %	Total MW at 2005	Total MW Added by 2005	Annual Average MW Added	Avg. Annual Growth Rate %	Total MW at 2005	Total MW Added by 2005	Annual Average MW Added
Medium Low	0.95%	5,596	503	50	1.06%	7,895	787	79	1.09%	7,597	779	78
Medium	1.99%	6,463	1,154	115	2.07%	9,104	1,689	169	2.16%	8,807	1,691	169
Medium High	3.00%	7,438	1,902	190	2.93%	10,473	2,630	263	3.16%	10,117	2,708	271

Table 3-3 shows the difference between the RAMPP-3 and RAMPP-4 medium forecasts for key years in the study period. It identifies how much of the difference is due to each of five factors: DSM implemented in 1994-1995, sale of the northern Idaho service territory, loss of sales to Wyoming resale customers, lower oil and gas loads in western Wyoming, and lower Trona loads in eastern Wyoming.

Table 3-4 shows key information for the load forecasts for the first 10 years of the study period. It shows the growth rate for energy, winter peak and summer peak over the forecast period, the total energy in MWa at the end of 2005, and the annual summer and winter peak MW in 2005. The growth rates are about 1 percent for medium-low, 2 percent for medium, and 3 percent for medium-high. The average annual MW added in the medium case, 169 MW, is lower than in RAMPP-3, when it was 185 MW a year.

Finally, the company evaluated whether the changes in the load forecast would have any effect on the forecast of DSM availability. The changes in the RAMPP-4 load forecast were in the industrial sector in Wyoming. RAMPP-3 assumed no DSM activity in Wyoming's industrial sector. Therefore, changes in the load forecast would have no effect on DSM availability.

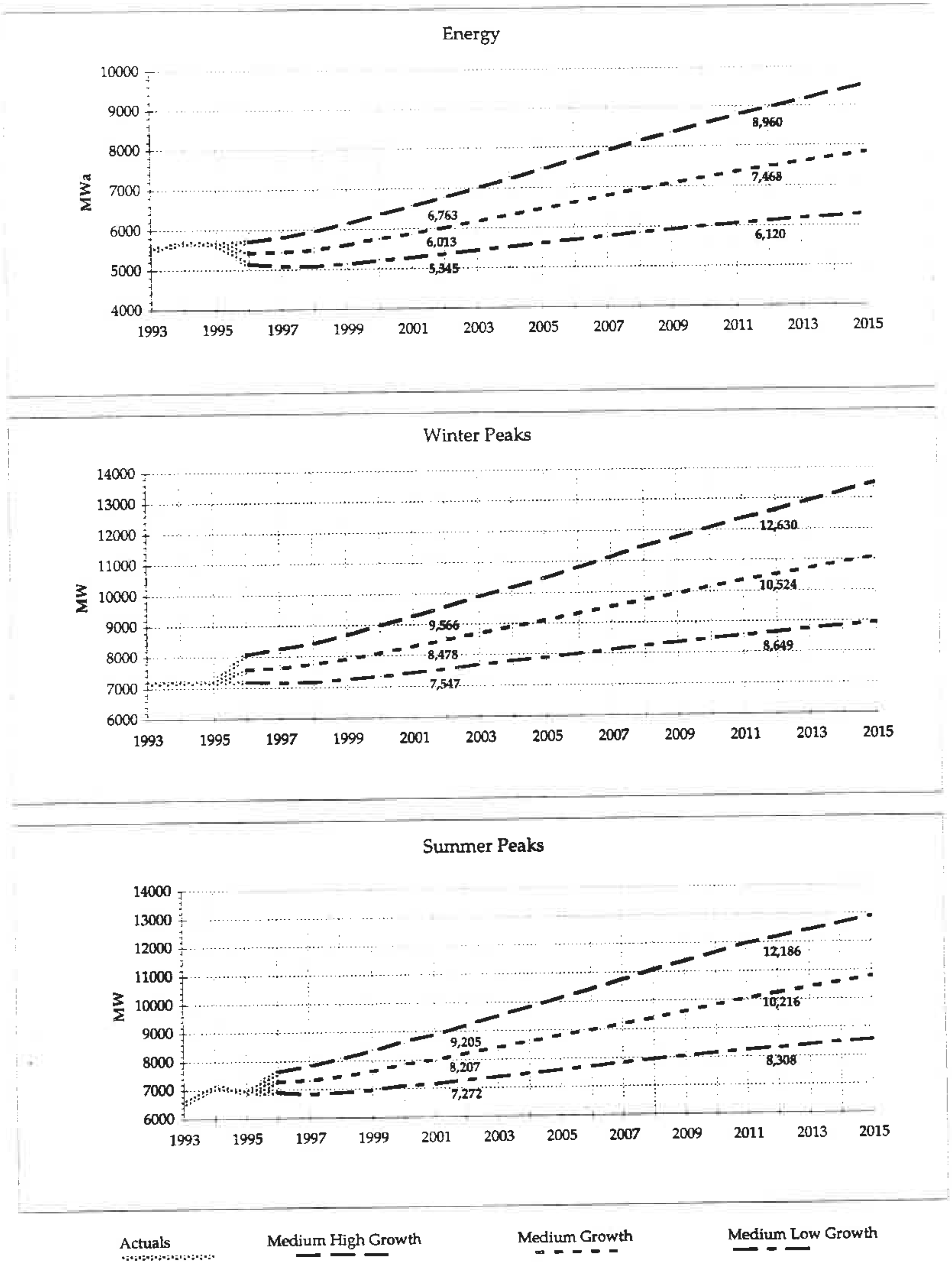
Graph 3-5 shows the three forecasts for RAMPP-4 for energy, winter peaks, and summer peaks. The range of total load growth in the forecasts by 2005 is about 2,500 MW and by 2015 is about 4,500 MW. The company believes this spread is sufficiently broad to capture the likely range of resource needs.

The net effect of the load changes on the system between RAMPP-3 and RAMPP-4 was to decrease the company's system load by 536 MW by the year 2005. This greatly reduced the need for new resources in RAMPP-4, compared to RAMPP-3. Graph 3-6 shows the difference in the RAMPP-4 forecasts compared to the RAMPP-3 forecasts for the winter peak load (the table shows winter peak because the winter peak for PacifiCorp's retail load remains higher than its summer peak through the planning period).

When considering the company's wholesale transactions, which includes both purchases and sales, the summer peak is higher than the winter peak. That is because the company has made more winter peak purchases than summer peak purchases, providing more winter

Total System Load Forecasts
Energy, Winter and Summer Peaks

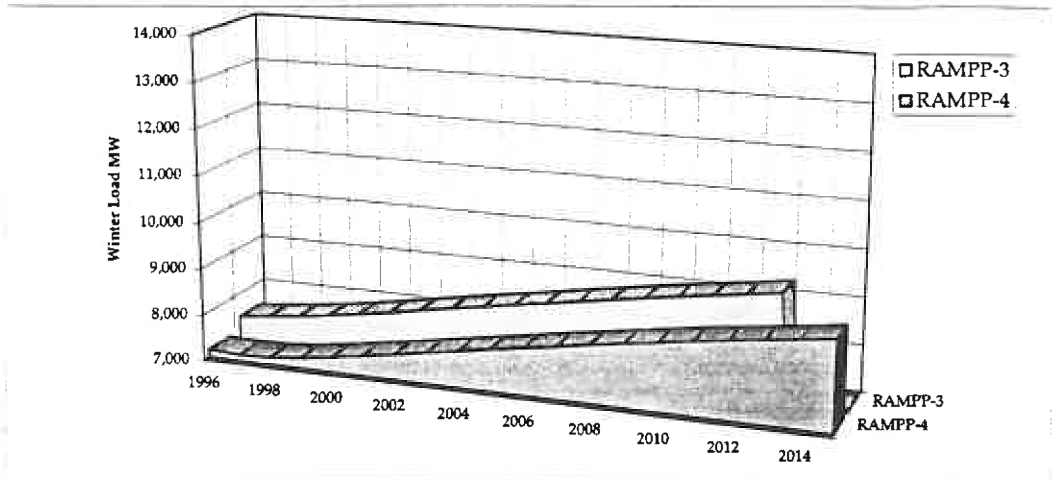
Graph 3-5



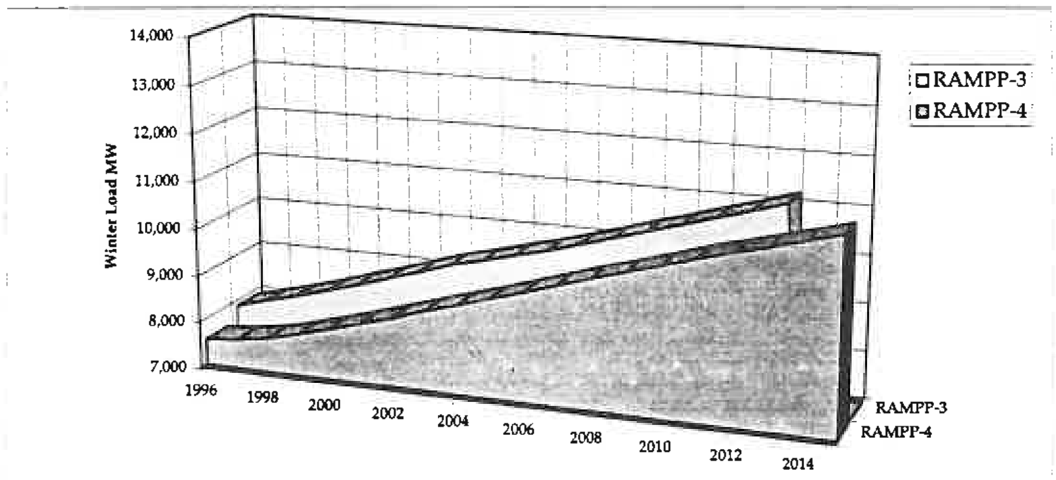
Forecasted Winter Peak Load (MW)

Graph 3-6

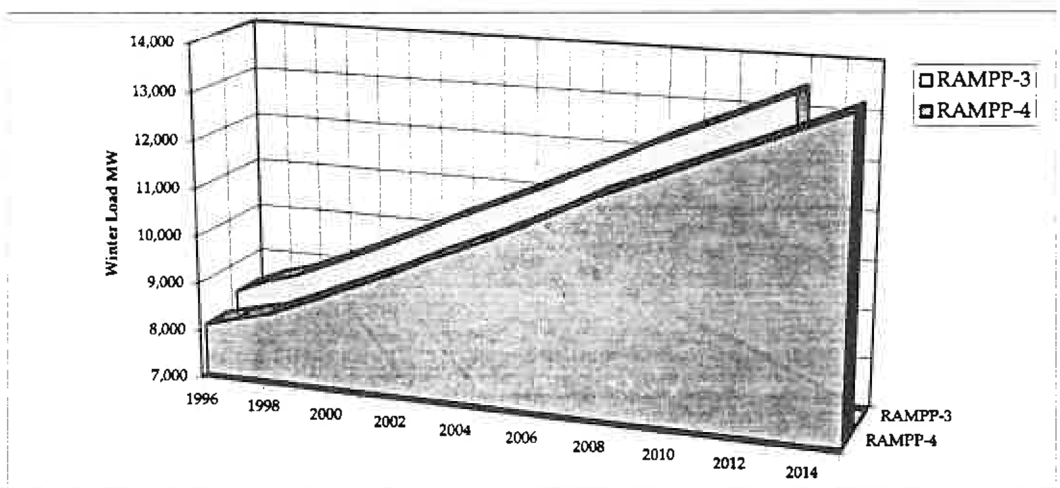
Medium Low



Medium Load



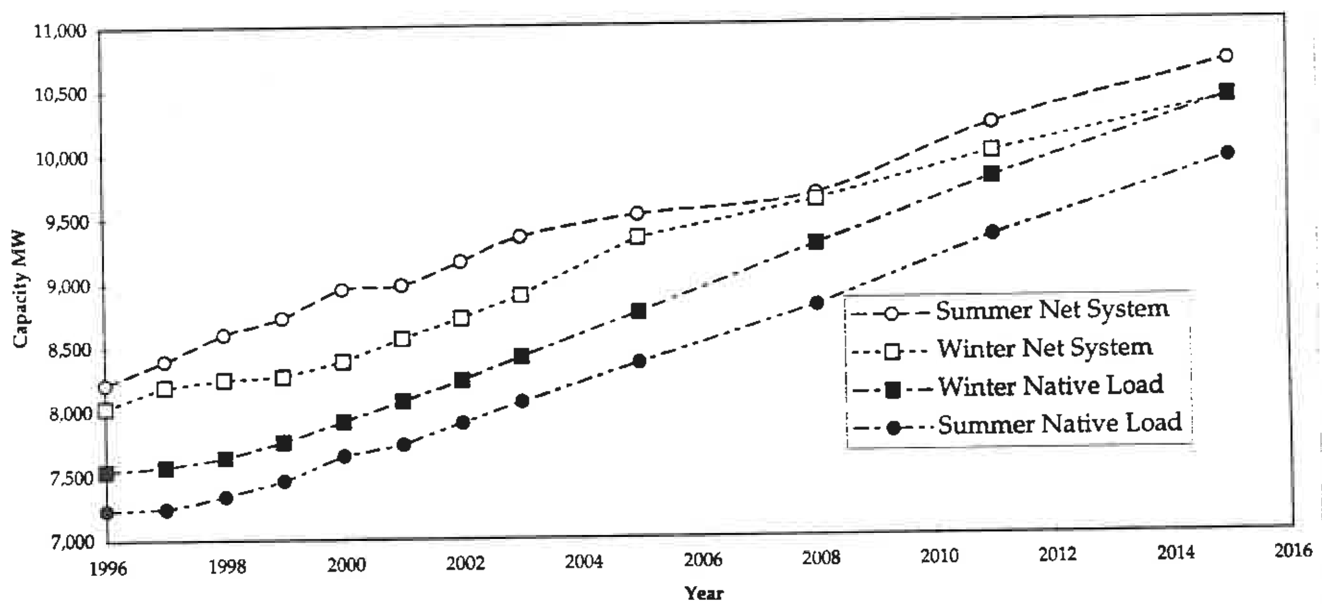
Medium High Load



Annual Peak Capacity (MW)

Table 3-07

	1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
Native Load												
Winter	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
DSM Programs	(30)	(62)	(97)	(133)	(170)	(207)	(243)	(280)	(352)	(461)	(563)	(689)
Winter Native Load	7,539	7,569	7,639	7,761	7,915	8,072	8,235	8,414	8,752	9,271	9,781	10,396
Summer	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
DSM Programs	(36)	(77)	(121)	(166)	(213)	(260)	(307)	(354)	(446)	(584)	(711)	(866)
Summer Native Loa	7,233	7,240	7,336	7,457	7,647	7,735	7,901	8,059	8,361	8,789	9,323	9,916
Winter less Summer	306	329	302	304	268	337	334	354	391	482	458	480
Native Load with Net Wholesale Transactions												
Winter	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
Firm Purchases	(963)	(825)	(830)	(824)	(799)	(774)	(769)	(761)	(319)	(269)	(269)	(269)
DSM Programs	(36)	(77)	(121)	(166)	(213)	(260)	(307)	(354)	(446)	(584)	(711)	(866)
Winter Net System	**8,033**	**8,193**	**8,248**	**8,267**	**8,386**	**8,558**	**8,716**	**8,892**	**9,334**	**9,616**	**9,976**	**10,387**
Summer	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
Firm Purchases	(809)	(758)	(658)	(638)	(632)	(607)	(600)	(579)	(424)	(424)	(374)	(341)
DSM Programs	(30)	(62)	(97)	(133)	(170)	(207)	(243)	(280)	(352)	(461)	(563)	(689)
Summer Net System	**8,215**	**8,396**	**8,602**	**8,727**	**8,948**	**8,976**	**9,159**	**9,349**	**9,516**	**9,665**	**10,199**	**10,679**
Winter less Summer	**(182)**	**(203)**	**(353)**	**(460)**	**(562)**	**(418)**	**(443)**	**(456)**	**(182)**	**(49)**	**(223)**	**(292)**



peaking resources for the system. Table 3-7 first shows the native load (retail) for winter and summer forecasted amounts, and the difference. Winter is larger than summer each year of the forecast. It then shows the forecasted amounts with wholesale sales and purchases added, and the difference. Now summer is larger than winter each year. The bottom of the page shows the same information in graph form.

The company will also need to develop load forecasts for the FERC for estimating available transmission capacity (ATC). The company will compute ATC based on its most current load forecasts. These will probably use the same process that produced the RAMPP load forecasts, but will be updated as needed so that the ATC reflects current best information and analysis.

Existing System

PacifiCorp's existing system for meeting retail load requirements includes existing power plants, turbine upgrades, and firm purchase and sale contracts.

Existing Power Plants

The company currently meets its energy requirements with about 82 percent coal generation, 5 percent company-owned hydro, and 11 percent power purchases. About 65 percent of the company's capacity comes from company-owned thermal generating plants, 10 percent from hydro generation, and 25 percent from power purchases (mainly hydro-based).

PacifiCorp has worked hard to maintain a low-cost system. PacifiCorp owns half the total production capacity of the 10 lowest-cost coal-fired power plants in the western United States. In 1994 the company's average production expenses were 37 percent below the national average: $12.37 per MWh at PacifiCorp versus $19.67 nationally. Eight of the 10 coal-fired plants operated by PacifiCorp set new production records in 1994. PacifiCorp's equivalent availability -- the amount of time a plant is available to produce at full load -- was 90 percent in 1994, one of the highest ratings in the country. Tables 3-8, 3-9, and 3-10 show the current system resources to meet summer peaking, winter peaking, and energy needs. The bottom of each table shows the regional distribution of the company's resources.

Winter Capacity of the Existing System (MW)

Table 3-8

	1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
APS New CTs	0	0	150	150	150	150	150	150	150	150	150	150
Carbon 1,2	175	175	175	175	175	175	175	175	175	175	175	175
Centralia 1,2	636	636	636	636	636	636	636	636	636	636	636	636
Cholla 4	390	401	401	401	401	401	401	401	401	401	401	401
Colstrip 3,4	144	144	144	144	144	144	144	144	144	144	144	144
Craig 1,2	165	165	165	165	165	165	165	165	165	165	165	165
Dave Johnston 1,2,3	772	772	772	780	780	780	780	780	780	780	780	780
Gadsby 1,2,3	235	235	235	235	235	235	235	235	235	235	235	235
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78	78
Hermiston	0	492	492	492	492	492	492	492	492	492	492	492
Hunter 1,2,3	1042	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112
Huntington 1,2	855	867	867	867	867	877	877	877	877	877	877	877
James River	52	52	52	52	52	52	52	52	52	52	52	52
Jim Bridger 1,2,3,4	1388	1396	1404	1412	1420	1420	1420	1420	1420	1420	1420	1420
Little Mountain	14	14	14	14	14	14	14	14	14	14	14	14
Naughton 1,2,3	675	675	675	675	675	675	675	675	675	675	675	675
Wyodak	256	256	256	262	262	262	262	262	262	262	262	262
Total Thermal	6877	7470	7628	7650	7658	7668	7668	7668	7668	7668	7668	7668
Mid-Columbia	417	417	417	417	417	417	417	417	320	194	28	0
Hydro Pacific	882	882	882	882	882	882	882	882	882	882	882	882
Hydro Utah	50	50	50	50	50	50	50	50	50	50	50	50
Blundell Geothermal	23	23	23	23	23	23	23	23	23	23	23	23
Wind	0	44	44	44	44	44	44	44	44	44	44	44
Total Renewables	1372	1416	1416	1416	1416	1416	1416	1416	1319	1192	1026	998
Purchased Power	841	703	708	702	677	651	646	639	197	147	147	147
BPA Purchase	1115	1112	1112	1110	1105	1105	1104	1104	1100	1100	1100	1100
Q.F. Contracts	122	122	122	122	122	122	122	122	122	122	122	122
T&D Efficiencies	20	27	34	41	48	55	62	66	74	86	98	102
Total Resources	**10347**	**10850**	**11019**	**11041**	**11026**	**11016**	**11018**	**11015**	**10479**	**10314**	**10160**	**10137**
Resources By Region												
OR CA WA (OWC)	4012	4386	4339	4336	4316	4299	4304	4304	3770	3652	3495	3471
Utah	3186	3271	3223	3225	3228	3240	3242	3244	3247	3250	3253	3254
Wyoming	1128	1153	1159	1173	1168	1163	1158	1153	1148	1098	1098	1098
Desert SW	633	644	894	894	894	894	894	894	894	894	894	894
Bridger	1388	1396	1404	1412	1420	1420	1420	1420	1420	1420	1420	1420
Total	**10347**	**10850**	**11019**	**11041**	**11026**	**11016**	**11018**	**11015**	**10479**	**10314**	**10160**	**10137**

Summer Capacity of the Existing System (MW)

Table 3-9

	1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
APS New CTs	0	0	150	150	150	150	150	150	150	150	150	150
Carbon 1,2	175	175	175	175	175	175	175	175	175	175	175	175
Centralia 1,2	636	636	636	636	636	636	636	636	636	636	636	636
Cholla 4	390	401	401	401	401	401	401	401	401	401	401	401
Colstrip 3,4	144	144	144	144	144	144	144	144	144	144	144	144
Craig 1,2	165	165	165	165	165	165	165	165	165	165	165	165
Dave Johnston 1,2,3	772	772	772	780	780	780	780	780	780	780	780	780
Gadsby 1,2,3	235	235	235	235	235	235	235	235	235	235	235	235
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78	78
Hermiston	0	434	434	434	434	434	434	434	434	434	434	434
Hunter 1,2,3	1042	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112
Huntington 1,2	855	867	867	867	867	877	877	877	877	877	877	877
James River	52	52	52	52	52	52	52	52	52	52	52	52
Jim Bridger 1,2,3,4	1388	1396	1404	1412	1420	1420	1420	1420	1420	1420	1420	1420
Little Mountain	0	0	0	0	0	0	0	0	0	0	0	0
Naughton 1,2,3	675	675	675	675	675	675	675	675	675	675	675	675
Wyodak	256	256	256	262	262	262	262	262	262	262	262	262
Total Thermal	6863	7398	7556	7578	7586	7596	7596	7596	7596	7596	7596	7596
Mid-Columbia	400	400	400	400	400	400	400	400	307	186	29	0
Hydro Pacific	922	922	922	922	922	922	922	922	922	922	922	922
Hydro Utah	90	90	90	90	90	90	90	90	90	90	90	90
Blundell Geothermal	23	23	23	23	23	23	23	23	23	23	23	23
Wind	10	10	10	10	10	10	10	10	10	10	10	10
Total Renewables	1445	1445	1445	1445	1445	1445	1445	1445	1352	1231	1074	1045
Purchased Power	687	635	536	516	509	485	478	457	302	302	252	219
BPA Purchase	1112	1112	1110	1105	1105	1104	1104	1100	1100	1100	1100	1100
Q.F. Contracts	122	122	122	122	122	122	122	122	122	122	122	122
T&D Efficiencies	20	27	34	41	48	55	62	66	74	86	98	102
Total Resources	**10248**	**10739**	**10802**	**10806**	**10815**	**10807**	**10807**	**10786**	**10546**	**10437**	**10242**	**10183**
Resources By Region												
OR CA WA (OWC)	3759	4147	4093	4073	4077	4061	4063	4046	3808	3696	3498	3438
Utah	3384	3469	3421	3423	3426	3438	3440	3442	3445	3448	3451	3452
Wyoming	1084	1084	1090	1104	1099	1094	1089	1084	1079	1079	1079	1079
Desert SW	633	644	794	794	794	794	794	794	794	794	794	794
Bridger	1388	1396	1404	1412	1420	1420	1420	1420	1420	1420	1420	1420
Total	**10248**	**10739**	**10802**	**10806**	**10815**	**10807**	**10807**	**10786**	**10546**	**10437**	**10242**	**10183**

Energy Generation of the Existing System (MWa)

Table 3-10

	1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
APS New CTs	0	0	26	36	43	63	65	45	37	56	26	1
Carbon 1,2	159	155	159	159	161	159	159	159	159	159	159	159
Centralia 1,2	570	570	581	581	581	576	576	576	576	576	576	576
Cholla 4	299	261	292	273	313	303	310	312	325	346	347	355
Colstrip 3,4	124	124	124	124	124	124	124	124	124	124	124	124
Craig 1,2	137	137	137	137	137	137	137	137	137	137	137	137
Dave Johnston 1,2,3	693	686	685	681	697	692	692	692	692	692	692	692
Gadsby 1,2,3	94	94	94	94	94	94	98	143	160	165	140	109
Hayden 1,2	63	63	63	63	63	63	63	63	63	63	63	63
Hermiston	113	438	438	438	438	438	438	437	430	429	421	411
Hunter 1,2,3	906	947	961	952	956	959	959	959	959	959	959	959
Huntington 1,2	755	766	751	751	766	770	770	770	770	770	770	770
James River	51	51	51	51	51	51	51	51	51	51	51	51
Jim Bridger 1,2,3,4	1217	1223	1244	1250	1245	1249	1249	1249	1249	1249	1249	1249
Little Mountain	9	9	9	9	9	9	9	9	9	9	9	9
Naughton 1,2,3	579	569	566	568	558	574	579	579	579	579	579	579
Wyodak	229	248	220	254	235	243	243	243	243	243	243	243
Total Thermal	5999	6342	6399	6422	6471	6504	6523	6548	6564	6608	6547	6489
Mid-Columbia	255	255	255	255	255	255	255	255	255	174	70	32
Hydro Pacific	498	498	498	498	498	498	498	498	498	498	498	498
Hydro Utah	55	55	55	55	55	55	55	55	55	55	55	55
Blundell Geothermal	22	22	22	22	22	22	22	22	22	22	22	22
Wind	6	14	14	14	14	14	14	14	14	14	14	14
Total Renewables	836	844	844	844	844	844	844	844	844	763	660	622
Purchased Power	435	382	351	342	332	323	320	317	277	260	256	236
BPA Purchase	311	310	310	307	307	307	307	307	305	305	305	305
Q.F. Contracts	122	122	122	122	122	122	122	122	122	122	122	122
T&D Efficiencies	14	19	25	30	35	40	45	48	54	62	71	74
Total Resources	7717	8019	8051	8068	8111	8140	8162	8186	8167	8121	7961	7848
Resources By Region												
OR CA WA (OWC)	2345	2621	2616	2608	2603	2595	2599	2600	2557	2482	2373	2307
Utah	2682	2722	2692	2689	2702	2724	2736	2782	2802	2809	2787	2756
Wyoming	975	992	969	999	992	993	990	986	983	966	966	966
Desert SW	499	461	531	522	569	579	589	569	575	616	587	569
Bridger	1217	1223	1244	1250	1245	1249	1249	1249	1249	1249	1249	1249
Total Resources	7717	8019	8051	8068	8111	8140	8162	8186	8167	8121	7961	7848

Energy in MWa as dispatched by the IPM model in the Base Case (Case 1).

RAMPP-4 includes system efficiency improvements as part of the company's existing system because PacifiCorp plans to pursue them as long as load growth remains within the medium-low to medium-high range. If load growth were to suddenly decrease, the company would re-evaluate its investments in a variety of areas, including efficiency improvements. Before a decision to pursue any efficiency improvement, the company does an updated analysis using the most recent avoided costs to assure that the improvement is a cost-effective capital expenditure.

The company currently plans to improve its thermal plants, hydro plants, transmission system and distribution system. Capital expenditures for ongoing refurbishment at the company's coal plants range from $7 to $11/kW. These costs are for modernization, equipment improvements, and regulatory compliance. They are not for upgrades to the capacity of particular units. This issue rose in RAMPP-3, when some commenters asked how much capital the company was spending on its existing coal plants, compared to the cost of new resources. To respond to the question, the RAMPP-3 report included this information. The company decided to include the information again in the RAMPP-4 report. As with any system improvement, the company assures that it can pass an avoided cost test before committing the capital.

Annual capital refurbishment expenditures are $48 to $72 million for the coal plants; divided by 6500 MW (the company's total coal installed capacity) yields $7 to $11/kW. If the company spent the same amount (in real dollars) every year for a 35-year plant life, the present value amount would be within a range of $110 to $175/kW. New resources currently cost a minimum of $500/kW. Because the cost of extending plant life is so low relative to new resource costs, RAMPP-4 includes refurbishment and maintenance as part of known changes to the existing system rather than as resource choices in the portfolio. The company coordinates the timing of refurbishment work with other maintenance work to minimize the total cost of the project.

Many of PacifiCorp's hydroelectric facilities are undergoing federal relicensing. The company is collaborating with other interested parties in this process to balance multiple interests. RAMPP-4 assumes the company will be successful in its relicensing efforts. However, the company recognizes that the success of relicensing will depend on any costs and restrictions which FERC may impose. The company will examine whether such costs and restrictions make relicensing cost-effective at the time. The RAMPP-3 report contains a more complete discussion of relicensing.

The hydro modeling uses a 50-year average of water levels. The reserve margin contribution is the average of monthly peak capacity during the winter and summer seasons.

The company is in the process of a 40 MW upgrade to the Yale project and a 6 MW upgrade to a Klamath River project. These upgrades should improve the hydro efficiency by 5 to 10 percent on the upgraded units. New runners are being installed on the Yale hydro units in 1995-96 to achieve higher capacity and efficiency. Similar changes are being considered for other units. Hydroelectric plant upgrades require a project-by-project engineering assessment of feasibility. The effect of the upgrade can be offset by other factors. The company has identified a number of potential upgrades on the Umpqua River, but most of them would not increase expected output. Instead, they would merely preserve the usability of that system given the expectation of more limits on stream flow and reservoir drafting that would be requirements of a new license.

Table 3-11 highlights the changes in the existing system from RAMPP-3 to RAMPP-4. RAMPP-4 began with an existing system that was about 220 MW smaller, but ended the study period in 2015 with an existing system about 400 MW larger. The increase resulted from the addition of Hermiston to the existing system. Adding Hermiston was the biggest change in assumptions about the existing system from RAMPP-3 to RAMPP-4: it added 474 MW to the system.

Turbine Upgrades

PacifiCorp continues to look for ways to maximize use of the company's assets. One opportunity involves improvements to steam turbines at the coal plants. Computer-assisted engineering and more sophisticated manufacturing techniques can improve the efficiency of the turbine blades on these steam turbines. Steam turbine manufacturers are recognizing the potential to retrofit better blades into existing steam turbines. The new blades can increase capacity and reduce heat rate.

Difference in Existing System in 2005 (Winter Peaks in MW)
Between RAMPP-3 and RAMPP-4

Table 3-11

Turbine Upgrades	RAMPP-3	RAMPP-4	Difference
Cholla 4	390	401	11
Dave Johnston 1,2,3	772	780	8
Hunter 1,2,3	1,041	1,112	71
Huntington 1,2	855	877	22
Jim Bridger 1,2,3,4	1,388	1,420	32
Wyodak	256	262	6
Total	4702	4852	150
Other Changes			
Hermiston		492	492
Mid-Columbia	417	320	(97)
Wind	13	44	31
Misc. Changes	4,764	4,771	7
Total	5,194	5,627	433
Total Changes to the Existing System	**9,896**	**10,479**	**583**

Resources by Region	RAMPP-3	RAMPP-4	Difference
OR CA WA (OWC)	3,360	3,770	410
Utah	3,144	3,247	103
Wyoming	1,122	1,148	26
Desert SW	882	894	12
Bridger	1,388	1,420	32
Total Changes to the Existing System	**9,896**	**10,479**	**583**

PacifiCorp is currently planning to implement cost-effective steam turbine improvements at ten units at six plants: Hunter 3, Huntington 1 and 2, all four Bridger units, Wyodak, Dave Johnston 4, and Cholla 4. RAMPP-3 did not include these upgrades because the technology only recently became available from GE.

The Hunter 3 unit is one facility scheduled for upgrading. This will enable it to perform at its original design condition, thus increasing the current steam flow to the turbine. Additional improvements to the steam turbine will also increase capacity. Together, these changes should increase net output from the Hunter 3 unit by 70 MW. Another effort will include a retrofit of the GE steam turbines at several other units in the system. New advanced steam turbine blade designs will increase capacity by about 79 MW. The combination is an approximate 150 MW improvement in total plant capacity.
In the mid-1980s, the company operated the Hunter 3 boiler at steam production levels close to its design rate of 3,341,000 lb steam per hour. This resulted in substantial damage to the boiler. The company then reduced boiler steam output by 10 percent to avoid further damage. Subsequent litigation against the boiler manufacturer resulted in damage awards to PacifiCorp. Negotiations with the boiler manufacturer have identified modifications to the boiler that can restore output to the original design capacity. The company expects to implement these modifications as a part of the litigation settlement.

PacifiCorp discussed the improvements with the steam turbine manufacturer (General Electric) to identify how to better use the restored steam flow from the steam turbine modifications. The higher steam flow can occur at pressures approximately 5 percent higher than the normal design pressure of 2400 psig. The steam turbine can operate more efficiently at these higher pressures with redesigned diaphragms and nozzle blocks. GE recommended redesign of the turbine clearances and replacing the turbine blades in the high and intermediate pressure sections of the boiler.

Thanks to new computer modeling techniques, the Advanced Aero turbine blade design focuses more steam into the center of the blades. This increases efficiency by reducing steam loss. The Advanced Aero design can improve capacity by as much as 2 percent and improve turbine cycle heat rate by a minimum of 1.5 percent. For the Hunter 3 turbine the Advanced Aero portion of the capacity increase is approximately 12 MW and the overall heat rate improvement is about

GE TURBINE UPGRADES

Table 3-12

Unit	Net RAMPP-3 Capacity MW (PacifiCorp Only)	Net Proposed RAMPP-4 Capacity MW (PacifiCorp Only)	MW Increase from Turbine Upgrades	1996 $/kW for Turbine Upgrade	Year of Turbine Upgrade
Dave Johnson #4	330.0	338.0	8.0	$613	1999
Jim Bridger #1	346.8	354.8	8.0	$367	1999
Jim Bridger #2	346.8	354.8	8.0	$367	1998
Jim Bridger #3	346.8	354.8	8.0	$367	1997
Jim Bridger #4	346.8	354.8	8.0	$367	2000
Wyodak	256.0	262.4	6.4	$613	1999
Cholla #4	390.0	401.0	11.0	$450	1997
Hunter #3	395.0	465.0	70.0	$210	1997
Huntington #1	420.0	432.0	12.0	$412	1997
Huntington #2	425.0	435.0	10.0	$396	2001
Total	3,603.2	3,752.6	149.4	$49,125,200	

Notes:

Hunter 3 upgrades include the capacity addition from overpressure operation

Aero Turbine upgrades are expected to improve turbine cycle heat rate by 1.5% except for Huntington 1 which is 1.7%

200 btu/kWh. The restoration of the steam flow combined with turbine nozzle block additions will add another 38 MW. Overpressure operation will increase output by 20 MW. Overall the cost to provide this added capacity at Hunter 3 of 70 MW (12 plus 38 plus 20) will be approximately $210/kW in 1996 dollars.

The company also asked GE to provide information on the potential advantages of retrofitting the Advanced Aero design steam turbine blades on other large GE steam turbines in PacifiCorp's system. Table 3-12 identifies the units planned for upgrade and the capacities before and after these projected modifications. The upgrades will occur during the next regularly scheduled overhaul for each indicated unit.

The cost-effectiveness of the upgrades varies because different units have different capacities. The company considers generator capacity, transformer capacity, and transmission availability in the final implementation decision. Although the cost of the turbine upgrade approaches $400 to $600/kW in some cases, economic analysis still tends to favors the upgrade since it increases capacity and energy with little or no fuel expense.

Other steam turbine manufacturers are looking into the modification of steam turbines with similar advanced designs. Some turbine manufacturers are marketing replacement components for competitors' machines as well as their own. The company will continue to look to improvements in the existing steam plants as a potential way to increase generation capacity.

Firm Wholesale Contracts

As the company's existing firm wholesale sales and purchase contracts expire, the amount of power available for retail customers changes. RAMPP assumes that the parties do not renew existing contracts. However, one sensitivity in RAMPP-4 tested the impact of this assumption by allowing all existing contracts to continue through the entire planning period. Since publication of the RAMPP-3 report, PacifiCorp has signed contracts for several new long-term purchases and sales. RAMPP-4 incorporates these new contracts, which include:

- The BPA Spring Exchange is effective June 1994, through May 2014. If Bonneville requests it, PacifiCorp will deliver up to 50,000 MWh during off-peak hours in March of each year, and

Bonneville will return the same amount of energy during off-peak hours from June 1 through July 15.

- The BPA Summer Exchange is effective for the same dates as the BPA Spring Exchange. Under this arrangement Bonneville will deliver to PacifiCorp up to 100,000 MWh per month each June and July, and PacifiCorp will deliver to Bonneville the same amount of energy in September, October, and November.

- The Washington Water Power (TWWP) Seasonal Exchange is effective June 1994 through March 2009. TWWP will provide up to 50 MW to PacifiCorp from June 16 through September 15 each year. In exchange, PacifiCorp will provide up to 50 MW to TWWP from December through February of the following year.

- TWWP Summer Purchase is effective June 16, 1994, through September 15, 2003. From June 16 through September 15, TWWP will provide 100 MW in 1994 and 1995 and 150 MW from 1996 to 2003.

- The Clark County PUD Interim Sale is effective from August 1995 through July 1998. PacifiCorp will deliver 100 MW during this time, and may terminate the agreement once the new Clark PUD combustion turbine project begins operating. The RAMPP-4 modeling included the Clark County PUD 100 MW interim sale as 100 MW per year at 100 percent capacity factor for 1996 through 1998.

- The Clark County PUD Storage and Integration Services Agreement will take effect with the commercial operation date of the PUD's combustion turbine project and continue through the 10th anniversary of that date. PacifiCorp's services will include dispatching, storage, marketing, spinning reserves, load factoring, and load following. For example, PacifiCorp provides peaking capacity to Clark as part of the load factoring service; this effectively doubles the capacity of their generation unit.

  May 1, 1995
- The City of Redding Agreement is effective June 1994 through May 2014. PacifiCorp will provide 50 MW to Redding.

RAMPP-4 modeling did not include the Clark Storage and Integration agreement for two reasons. First, at the time RAMPP-4 modeling began the company had to freeze all the inputs so that it could achieve consistency of assumptions across all of the cases. At that time, in early 1995, the agreement was in place but the parties had not worked out all of the details. In fact, the parties are still negotiating some of the details. The company decided to wait until RAMPP-5 to model the impact of this agreement, when it would have more time to understand the implications. Second, PacifiCorp will be marketing surpluses for Clark, moving power off-peak to on-peak, and providing other power management services, but the company will not be providing power for Clark loads. Thus, the only anticipated burden on PacifiCorp's system will be some small amount of reserve requirements, perhaps in the 10 to 20 MW range. RAMPP-5 will include this adjustment to reserve margin requirements.

Over the first ten years of the planning period, the company's firm wholesale purchases decline more than the firm wholesale sales. This has the effect of increasing the need for new resources. As measured in winter MW, the purchases decline from 963 MW in 1996 to 319 MW in 2005, for a loss of 644 MW of resources. Sales decline from 1,463 MW to 995 MW, for a decline of 468 MW. Thus, there is a net loss to the system of 176 MW.

DSM Portfolio

PacifiCorp can also help customers use electricity more efficiently through demand-side management (DSM). Integrated resource planning considers DSM as well as supply-side resources (SSR).

Total resource cost (TRC) is one measure of the cost of DSM and SSR. It is the measure required by IRP regulatory rules. For supply-side, TRC is the same as utility cost. However, for demand-side it is different. For demand-side, TRC includes the cost to customers and reduces total program cost for non-energy benefits. For example, DSM can result in lower operating costs or reduced maintenance costs. These reductions do not in fact reduce the cost of DSM for the utility; however, TRC calculations require that for modeling, DSM costs are reduced by the value of the non-energy benefits.

There are three key components in the preparation of DSM data for RAMPP-4:

1) Introduction of resource bundles (groups of DSM measures that have similar levels of cost).

2) Updates to the penetration rates for each resource bundle.

3) Updates to the total resource costs for each resource bundle.

Resource Bundles

In RAMPP-3, each case included a fixed amount of DSM. PacifiCorp abandoned this approach for RAMPP-4 and replaced it with a resource bundle approach. This allowed the model to select the amount of DSM that was cost effective in each case. The idea was to offer to the model groups of DSM measures that could compete in cost with supply-side resources. The model could then select the optimum level of DSM.

For DSM purposes PacifiCorp divides its customers into lost-opportunity markets and discretionary markets. The company created a total of 57 bundles as inputs to the IPM model. The Appendix provides additional information about the DSM process for RAMPP-4.

The lost-opportunity markets include commercial new construction and residential new construction. In these markets PacifiCorp's policy has been to acquire all cost-effective DSM at the time of construction, to avoid losing one-time opportunities. The company first screened the savings in each sub-market, such as offices, retail, grocery, etc., using different cost-effectiveness thresholds. By testing alternative bundle groupings, the company determined that using 35 mills/kWh as a bundle cut-off for the FinAnswer 12000 program and 40 mills/kWh for the Energy FinAnswer maximized the amount of measures and the amount of savings that the IPM model would select. For example, the company made sure that the average TRC cost for the second or third bundle was just below the TRC cost of the competitive supply-side resource. This guaranteed that when the system needed additional resources, the model would select all DSM bundles at or below that TRC level.

DSM Penetration Rates

Table 3-13

MARKET	1996	1997	1998	2000	2005	2010
Commercial New Construction (1)	75%	85%	85%	85%	85%	85%
Commercial Retrofit	4%	4%	4%	4%	4%	4%
Industrial	4%	4%	4%	4%	4%	4%
Irrigation	2%	2%	2%	2%	2%	2%
Residential Programs-Existing Stock						
Compact fluorescent & water saving measures	4%	4%	4%	4%	4%	4%
Residential Programs-New & Replacement						
Res. appliance-New-CFL & water saving measures	30%	40%	50%	75%	75%	75%
Res. appliance-SERP (2)	5%	6%	6%	7%	10%	12%
Res. appliance-H.axis Washers (2)	1%	2%	3%	5%	10%	15%

(1) Percent of annaul new construction

(2) Percent of annual replacement. Includes stock replacement and new additions.

Total Resource Cost for DSM Bundles

Table 3-14

Market and Bundle Descriptions	Administration Cost levelized Mills/kWh	Total Resource Cost Mills/kWh	Program LIFE Years	PV 50 yr life Cycle $/mwh IPM input
Residential Existing Appliance Market				
Bundle 1- Water savings measures	8	-15	15	0
Bundle 2- Compact FL measure	3	16	7	522
Residential Weatherization Market				
Home comfort (Bundle 1)	7	83	23	1451
Low income + bidding (Bundle 2)	10	51	19	883
SGC retro (Bundle 3)	15	53	23	922
Residential New Construction Market	5	22	45	388
Residential New Appliance Market				
Water saving and CFL measures	4	-16	15	0
SERP refrigerators	0	7	19	116
Horizontal Axis Washing machine	1	-107	12	0
Commercial New Construction Market				
FinAnswer- 40 mill cut off	3	25	30	427
EF 12,000- 35 mill cut off	2	25	30	436
Commercial Retrofit market				
Bundle 1, 0-25 cut off	3	25	30	439
Bundle 2, 25-27	2	30	30	527
Bundle 3, 27-29	1	31	30	545
Bundle 4, 29-40	1	39	30	682
Industrial Market				
Bundle 1, 13 mill cut off	4	13	15	238
Bundle 2, 21 mill cut off	3	21	15	367
Bundle 3, 23 mill cut off	2	24	15	424
Bundle 4, 27 mill cutoff	2	25	15	451
Irrigation Market	5	38	15	597
Residential Water heater Load Control	9	9	20	289

Discretionary markets include commercial and residential retrofits. In these markets the timing and level of DSM activity can vary. The company created from two to four bundles for each market (commercial and residential) after establishing a lower and upper limit for cost-effectiveness for each bundle. As with the lost-opportunity markets, the company first screened the savings in each sub-market and tested alternative bundle groupings to arrive at bundles that maximized the amount of measures and the amount of savings that the model would select. Table 3-14 shows the cost-effectiveness limit for each bundle in the discretionary markets.

Penetration Rates

Penetration rate is the assumed percentage of total DSM savings available that could be captured each year. For example, if the total available amount of savings from a particular bundle has a penetration rate of 4 percent, then after 25 years the model would have selected the entire amount. Table 3-13 shows the penetration rates used in RAMPP-4 for each program. The data inputs assumed that the lost-opportunity programs reach a mature penetration rate of 75 to 85 percent of their potential market by the fifth year of the program. The discretionary programs had an annual penetration rate of 4 percent.

The penetration rate input into the model for each bundle was key to the amount of DSM selected in each year. The DSM technical subgroup of the RAMPP advisory group worked closely with the company to explore alternative ramp rates and their impact on the amount of DSM selected by the model. A higher ramp rate resulted in less DSM selected in the early years, and a delay of some programs for a few years. This is because the higher penetration rate would allow the model to reach the desired total penetration quickly. A lower penetration rate resulted in the model selecting the program earlier, because it takes longer to reach the desired penetration. Thus, lower penetration rates can result in a fuller menu of programs in the early years. The RAG technical group and the company agreed that it was more desirable to have a complete menu of programs operating from the beginning of the planning period. Therefore, both groups recommended a lower ramp rate to achieve a broader range of programs in the early years.

Total Resource Costs

Total resource costs include the cost of the measures in each bundle and program administration costs, adjusted for the assumed life of the measure. Table 3-14 shows the administration cost, total resource cost, and 50-year present value of life cycle cost.

The company's RAMPP-4 assumptions regarding customers' level of co-funding of the incremental cost of the measures were the same as in RAMPP-3. The RAMPP-3 assumption was that after 1998, customers will pay half of the measure cost for the commercial and industrial retrofit projects.

One of the comments on the RAMPP-4 draft requested a clarification of the company's treatment of industrial DSM. From a practical program implementation viewpoint, it is PacifiCorp's standard practice to recommend and fund the most-efficient and cost-effective measures. For new facilities, the company finances the incremental cost (the difference between the cost of what the customer wants to do and the cost of the most-efficient cost-effective industry standard). For existing facilities the company recommends to the customers the measures that would bring them from their current practice to a most-efficient industrial standard. From a modeling perspective, the concept of lost-opportunity can be appropriate for industrial facilities. However, the forecasting model used in estimating the consumption levels from the industrial sector does not separate new from existing facilities. The DSM modeling of energy efficient technologies does not separate savings into new and existing equipment. Very few industrial facilities are built within the company's service territory each year. Most new operations are expansions of existing or modification of current processes. As a result, in the RAMPP-3 and RAMPP-4 modeling for industrial sectors there are no distinction made for new facilities and existing facilities.

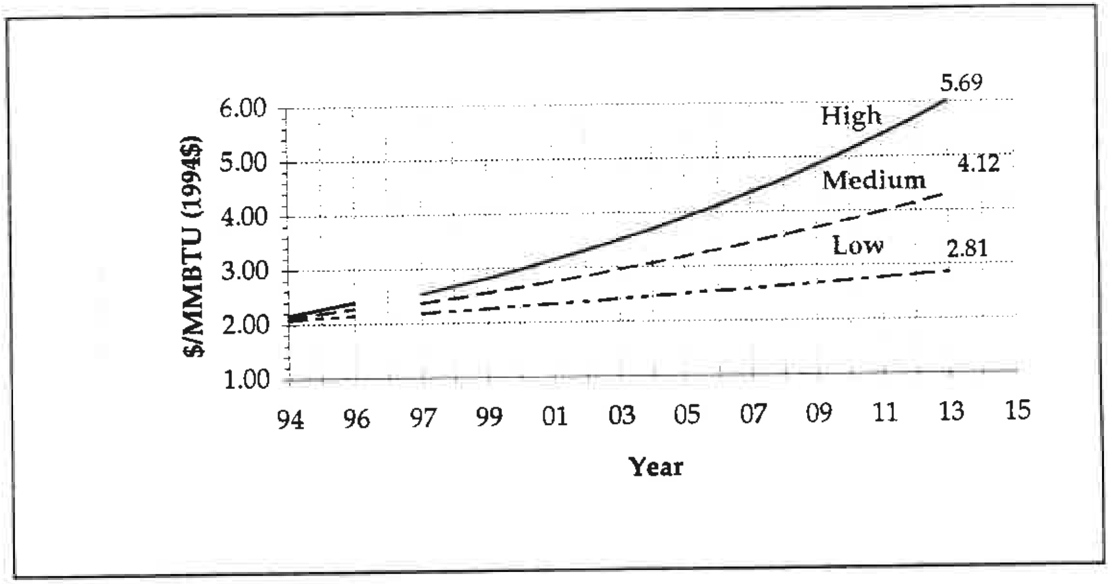
Gas Prices

The gas price assumptions used in RAMPP-4 included a starting price, escalation rates for the 20-year study period, and other costs for specific sites.

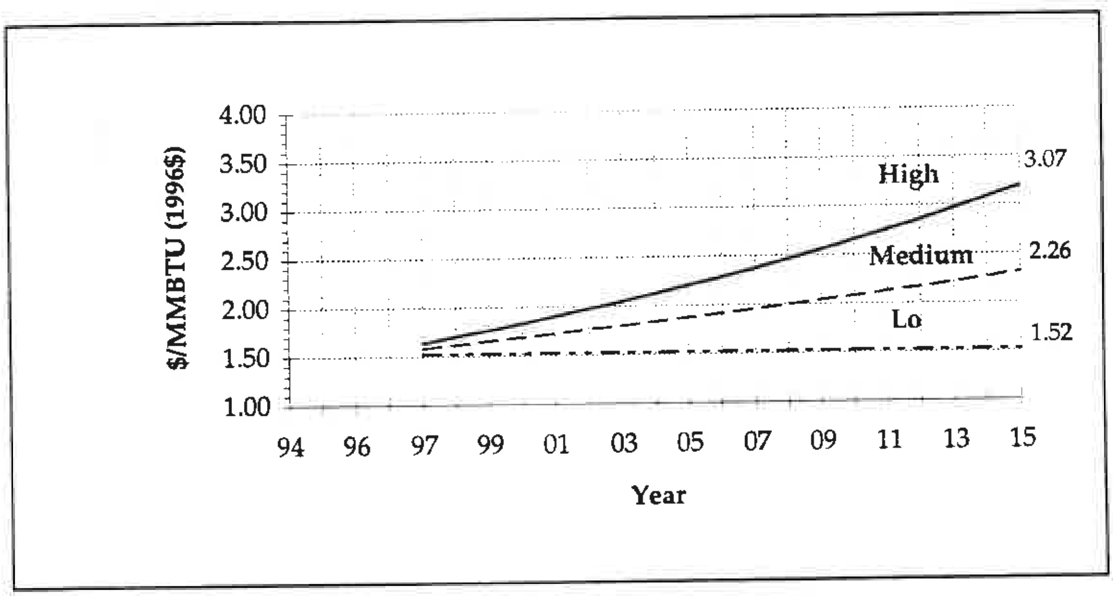
Long Term Growth Rates for Natural Gas
Well Head Gas Pricing
RAMPP-3 and RAMPP-4

Graph 3-15

RAMPP-3



RAMPP-4



To develop the starting price, the company examined the futures market for 1995 and the basis differential (price difference in gas available at Henry Hub, Louisiana and gas available in the Rocky Mountain area) at the end of December 1994. The NYMEX futures prices at Henry Hub for 1995 averaged $1.72/MMbtu, based on the markets closing on December 27, 1994. On December 27, 1994, a telephone solicitation for a 1995 basis differential in Rocky Mountain markets resulted in a market value of $0.32/MMbtu. Subtracting the basis differential from the NYMEX price ($1.72 less $0.32) yielded $1.40/MMbtu as the 1995 starting price for natural gas in RAMPP-4. This represents the expectation for the cost of spot gas.

PacifiCorp used price escalation forecasts from major forecasters as well as the company's own experience in the marketplace. RAMPP-4 included three alternative real escalation rates for gas: a low escalation at 0 percent, a medium rate of 2.11 percent, and a high rate of 3.78 percent. Thus, given an assumed inflation rate of 3.3 percent, these three rates in nominal terms became 3.3 percent, 5.5 percent, and 7.2 percent. These are similar to other regional forecasts.

Because gas prices have come down significantly since RAMPP-3, the company used the low real escalation rate in RAMPP-3 of 2.11 percent as the medium escalation rate for RAMPP-4, and the RAMPP-3 medium real escalation rate of 3.78 percent as the high escalation rate for RAMPP-4. Graph 3-15 shows the escalation of gas prices for the 20-year planning period for RAMPP-3 and for RAMPP-4. The scales for $/MMbtu are different for the two RAMPP cycles: the scale stops at $6.00 for RAMPP-3; it stops at $4.00 for RAMPP-4.

Beginning with $1.40/MMbtu as the 1995 starting price, the company developed a 1996 starting price for each of the three escalation rates through the following steps: 1) increase $1.40 by 5 percent for tax and shrinkage to $1.47, 2) increase $1.47 by inflation of 3.3 percent and by each of the three real escalation rates. This led to beginning 1996 prices for gas of $1.52/MMbtu for the low escalation rate, $1.55 for the medium escalation rate, and $1.58 for the high escalation rate. To these amounts the company added region-specific costs for transportation and storage, as shown on Table 3-16. Transportation and storage costs declined slightly from RAMPP-3 to RAMPP-4.

Gas Transportation & Storage

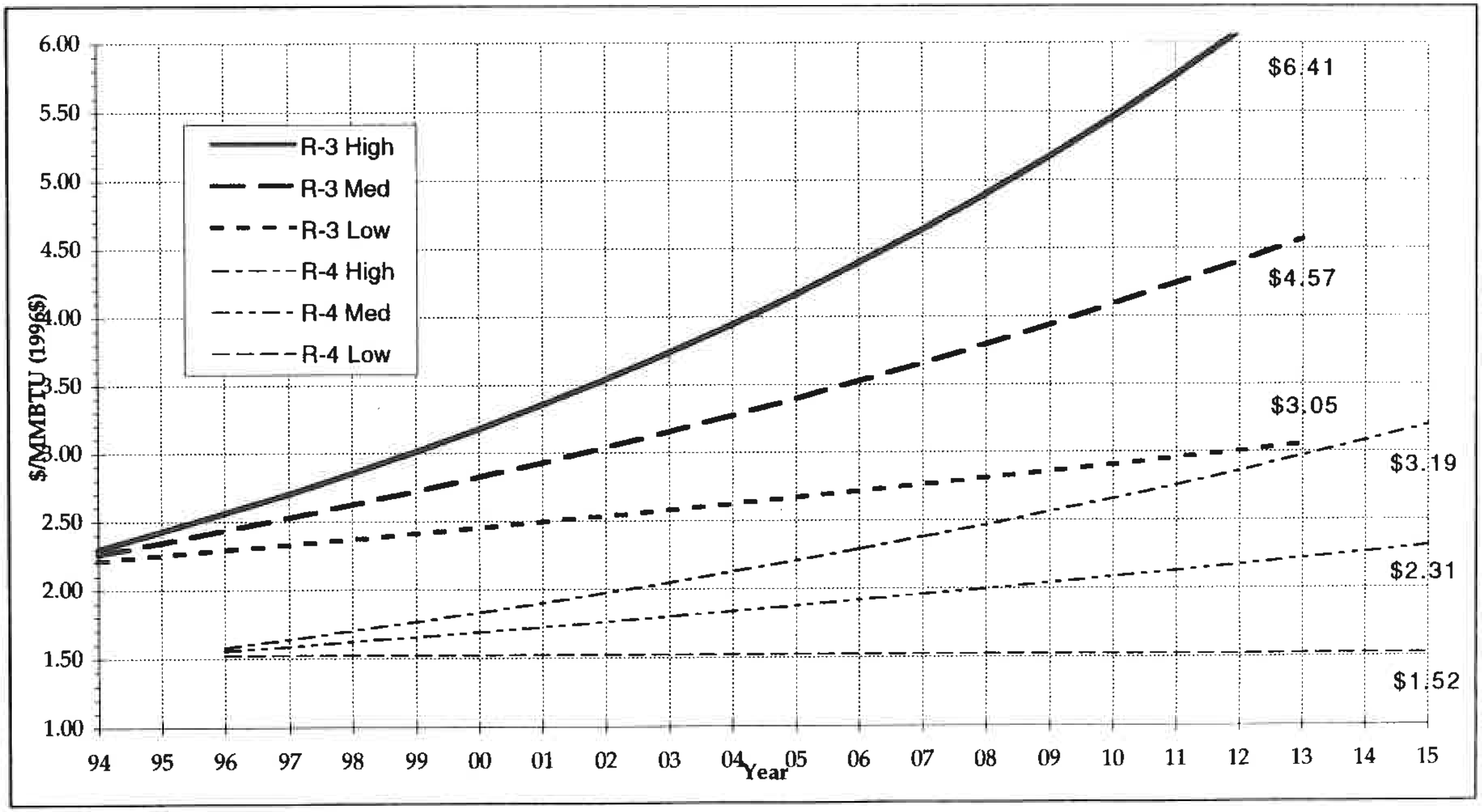
Table 3-16

Variable Costs in Cents/MMBtu	Combined Cycle		Simple Cycle	
	Pacific NW	Mountain	Pacific NW	Mountain
1996 Gas Price	155.1	155.1	155.1	155.1
Transportation	46.5	20.7	-	-
Storage	-	-	11.4	5.2
Total Variable	201.6	175.8	166.5	160.3

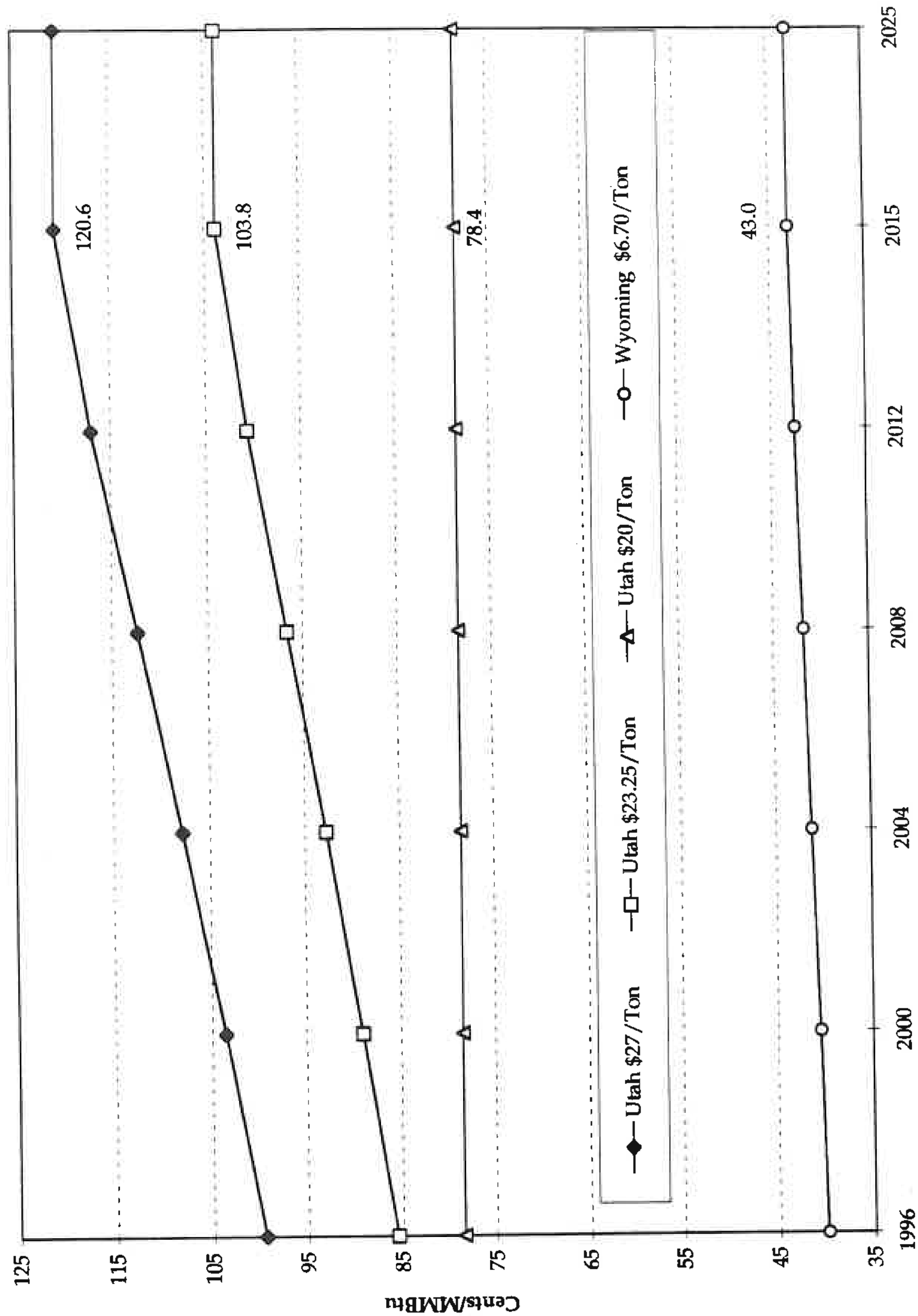
Fixed Costs $/kW-yr	Combined Cycle		Simple Cycle	
	Pacific NW	Mountain	Pacific NW	Mountain
Total Fixed	-	-	$ 35.91	$ 21.51

Long Term Growth Rates for Natural Gas
Well Head Gas Pricing
RAMPP-3 and RAMPP-4 Combined

Graph 3-17



Coal Prices
Graph 3-18



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ljh N3.18 Compare R-4 to R-3

The lower gas price expectations, both in starting price and escalation rates, significantly lowered the expected cost of gas-fired resources in the RAMPP-4 portfolio, compared to RAMPP-3. Graph 3-17 shows the starting prices and the three escalation rates in RAMPP-3 and RAMPP-4. Graph 3-17 combined the curves onto one graph to better show differences between RAMPP-3 and RAMPP-4. Overall, the gas price changes increased the attractiveness of gas-fired resources relative to coal-fired resources and DSM.

These gas prices for new resources assumed that the company will be able to buy gas at spot prices for an extended period of time. Based on experience in the gas markets, the company believes this is a reasonable assumption.

Coal Prices

PacifiCorp commissioned BXG, Inc. to perform a market study to evaluate coal supply and demand conditions in Utah and the Powder River Basin in Wyoming. BXG examined existing capacity, planned capacity additions, planned new mines, and reduction of capacity in each region. BXG then matched the projected capacity with demand forecasts to determine if there was sufficient existing over-capacity, or if the market would support incremental capital additions or new greenfield mine development. The analysis showed that prices for existing and incremental capital additions will fall in one price range, while a contract that requires a new mine will have prices that are 20 to 25 percent higher. PacifiCorp used information from the BXG study to develop the RAMPP-4 coal price assumptions.

RAMPP-3 used a $12/ton price for the coal needed for new coal-fired resources in Utah and $7.20/ton for new coal in Wyoming. It also included a sensitivity level of $24/ton for new coal in Utah. RAMPP-4 used a supply curve approach for new Utah coal. Coal at $20/ton is available for a new 400 MW unit at the Hunter plant; the next 400 MW of new coal plants would use $23.25/ton coal; and all additional units would use coal that costs $27/ton. Each of these levels escalates at a real rate of 1.027 percent per year. In RAMPP-3, the $12/ton coal escalated at a zero percent real rate, and the $24/ton coal escalated at 4.95 percent real rate.

For Wyoming, a great deal of new coal is available at $6.70/ton, only slightly less than the RAMPP-3 assumption of $7.20/ton. In addition, coal prices in Wyoming escalate at 0.4 percent real per year for RAMPP-4, compared to 0.9 percent real in RAMPP-3. Graph 3-18 shows the RAMPP-4 coal prices for Utah and Wyoming for the entire 50-year study period.

Supply-Side Portfolio

In RAMPP-4 PacifiCorp made several changes to the estimated cost of new supply-side resources. The first one was updating capital and operation and maintenance costs to 1/1/96, using an inflation rate of 3.3 percent. The revised capital costs assumed construction costs in 1996 dollars with AFUDC included in real (non-escalated) dollars. They also included indirect costs: non-engineering PacifiCorp personnel time required, administrative and general expense, working capital, startup, and other indirect costs.

The major changes to the supply-side portfolio from RAMPP-3 included the following:

- **Gadsby Repowering**: RAMPP-4 included an option to repower the existing gas-fired steam units at the Gadsby plant: Unit 1 is 60 MW, Unit 2 is 75 MW, and Unit 3 is 100 MW. Repowering would involve adding an advanced gas turbine and heat recovery steam generator to each existing unit. Equipment would generate steam from the gas turbine exhaust for use in the existing steam turbines. Repowering would more than double the capacity of each unit, improve the efficiency of the units by about 50 percent, and reduce emissions. Such a modification to the Gadsby Plant would effectively convert the existing steam units to a combined cycle facility.

  The Gadsby repowering would provide about 331 MW of summer capacity. The exact capacity depends upon ambient air temperature, the type of turbine selected (GE, Westinghouse), the turbine technology ("F" or "G"), and the method selected to handle the mismatch between the Gadsby steam turbines and actual gas turbines. For modeling purposes the plant size is 320 and the maximum MW available is 331 MW. This means that the IPM model could select at most 320 MW of Gadsby repowering in a given year.

When the model selects this option, the tables showing amounts of new resource additions include only the net increase in capacity from the Gadsby conversion. The Appendix includes additional information on the Gadsby conversion option.

- **Combined Cycle Combustion Turbine:** Large combined cycle facilities assume an "F" technology gas turbine facility. The cost estimates assume a one-unit plant. The costs include selective catalytic reduction (SCR) equipment to reduce emissions. The costs also assume siting near backbone transmission facilities and near an interstate gas pipeline.

- **Pulverized Coal:** The pulverized coal costs in RAMPP-4 include SCR equipment. Regulations will eventually require SCR as the best available control technology for NOx emissions at future coal-fired steam plants.

- **Integrated Gasification Combined Cycle**: The portfolio includes IGCC plants because of their superior environmental characteristics and the increasingly commercial status of the technology. The portfolio does not include fluidized bed coal because it is not as commercially available as IGCC.

- **Wind**: The costs of wind power reflect the expected costs from the Columbia Hills and Foote Creek developments in the OWC and Wyoming regions, respectively. The lead time in these two areas for additional wind generation is only two years because the developer has already performed a significant amount of permitting and development work. RAMPP-3 separately identified wind costs by geographic area. RAMPP-4 identified wind costs by area and by the transmission available in the area. Non-firm wind costs included minimal additional transmission. Firm wind costs include the additional transmission equipment necessary to provide that power to the system on a firm basis.

  RAMPP-3 assumed an unlimited amount of new wind resources to be available. That was not an appropriate assumption since wind siting would tend to follow a supply curve with the best (lowest cost) sites being developed first. RAMPP-4 re-examined that assumption and limited the amount of wind to what was available at the two sites already under development: Columbia Hills and Foote Creek. The company assumed that the next wind project would be expansion of an already sited wind project. This lowered the cost of the new wind project but also lowered the amount of wind resource available at that price. This change in assumptions affected only the environmental cases, for those are the only cases in which the model selected wind.

- **Summer Peak Purchases**: The portfolio included a summer peak purchase option through 2002. Summer peak purchases would not be the most cost-effective solution after that date because winter peak needs and energy needs begin in 2003. It therefore becomes cost-effective to add year-round resources starting in 2003. The price for summer peak purchases is $2/kw month for three months, or $6/kw for the season.

- **Simple Cycle Combustion Turbines**: The portfolio included only large simple cycle combustion turbines because large units are more cost-effective than smaller units. RAMPP-4 costs for the simple cycle machines represent the average costs of an initial unit and an extension unit. Any site would likely have a two-unit plant.

- **Compressed Air**: Peaking choices for RAMPP-4 included a compressed air energy storage (CAES) plant. A CAES plant would compress air into a natural cavern using the compressor on a gas turbine and off-peak coal energy. When the system needs power, the compressed air passes through a combustion turbine, then drives a generator to produce electrical power. The costs reflect one developer's proposal in Arizona.

The costs of resources used in RAMPP-4 modeling reflected generic technologies. The actual costs which PacifiCorp would incur in acquiring a specific resource are highly site specific and may be more or less than these estimates. The portfolio identifies resources by geographic area. Costs for the same technology vary by area because of differences in altitude and gas transportation costs.

Supply-Side Portfolio: Non-Cost Characteristics

Table 3-19

Description	MW Available in 1st Year or Plant Size	1st Year Available	Maximum MW Available	Depreciation Life (years)	Tax Life (years)	Heat Rate (Btu/kWh) Incremental	Heat Rate (Btu/kWh) Average	Emissions (lbs/MMBTu) NOX	Emissions (lbs/MMBTu) CO2
Utah Gadsby Repower	320	2000	331	50	35	5,039	7,846	0.0160	118
Utah Cogen 2	210	2000	420	50	35	6,200	6,800	0.0160	118
OWC Cogen 2	470	2000	1,320	50	35	6,200	6,800	0.0160	118
OWC Cogen 1	160	2000	320	50	35	4,300	5,500	0.0160	118
Utah Cogen 1	39	2000	39	50	35	4,300	5,500	0.0160	118
Utah Combined Cycle	450	2000	Unlimited	50	35	7,167	7,517	0.0160	118
OWC Combined Cycle	450	2000	Unlimited	50	35	7,167	7,517	0.0160	118
Wyo Combined Cycle	450	2000	Unlimited	50	35	7,167	7,517	0.0160	118
Utah PC Hunter 4 $20/Ton	400	2002	400	50	45	9,583	10,062	0.1000	206
Wyo PC Wyodak 2	264	2002	264	50	45	11,305	11,900	0.1000	206
Wyo Coal $6.70/Ton	330	2002	Unlimited	50	45	10,246	10,758	0.1000	206
Utah IGCC Hunter 4	262	2002	262	50	35	7,980	8,400	0.1000	206
Utah Coal $23.25/Ton	400	2002	1,250	50	45	9,583	10,062	0.1000	206
Wyo IGCC Wyodak 2	210	2002	210	50	35	7,980	8,881	0.1000	206
Wyo IGCC CT	262	2002	Unlimited	50	35	7,980	8,881	0.1000	206
Utah IGCC CT	262	2002	Unlimited	50	35	7,980	8,400	0.1000	206
Utah Coal $27.00/Ton	400	2002	1,250	50	45	9,583	10,062	0.1000	206
Utah Wind Non-firm	100	1998	200	50	20	N/A	N/A	N/A	N/A
Wyo Wind Non-firm	100	1998	200	50	20	N/A	N/A	N/A	N/A
OWC Geothermal	100	1999	300	50	30	10,000	10,000	N/A	N/A
Utah Geothermal	100	1999	300	50	30	10,000	10,000	N/A	N/A
Utah Wind Firm	150	1998	300	50	20	N/A	N/A	N/A	N/A
Wyo Wind Firm	150	1998	300	50	20	N/A	N/A	N/A	N/A
OWC Wind Non-Firm	100	1998	200	50	20	N/A	N/A	N/A	N/A
OWC Wind Firm	150	1998	300	50	20	N/A	N/A	N/A	N/A
Utah Simple Cycle CT	370	2000	Unlimited	50	30	10,556	11,083	0.0900	118
Wyo Simple Cycle CT	320	2000	Unlimited	50	30	10,556	11,083	0.0900	118
OWC Simple Cycle CT	370	2000	Unlimited	50	30	10,556	11,083	0.0900	118
OWC Bridger Trans L	500	2000	1,000	50	50	8,846	10,229	0.4500	211
OWC Htr/OWC Trans L	500	2000	1,000	50	50	9,182	10,332	0.4500	219
OWC Pump Storage	200	2001	500	75	50	N/A	N/A	N/A	N/A
Utah Compressed Air	340	2000	340	50	35	4,700	4,700	0.0160	118
Utah Pumped Storage	200	2001	200	75	50	N/A	N/A	N/A	N/A

Not well supported

Supply-Side Portfolio: Cost Components (in 1996 $)

gen cost real levelized gen cost from 2003-2045 converted to mills/kwh using incremental heat rate

cents/mmbtu/100 000 * inc heat rate

Table 3-20

Description	Capital Cost: Unit Cost ($/kW)	Capital Cost: Trans-mission ($/kW)	Capital Cost: Payment Factor (%)	Capital Cost: Annual Payment ($/kW Year)	Fixed Cost: O&M ($/kW Year)	Fixed Cost: Expected Utilization Rate	Fixed Cost: Ttl. Capital & Fixed Cost (Mills/kWh)	Energy Cost in 2003: 1st Year (Cent/MMBTU)	Energy Cost in 2003: Levelized (Cent/MMBTU)	Energy Cost in 2003: Levelized (Mills/kWh)	Variable O&M (Mills/kWh)	TOTAL COST (Mills/kWh)
										15.45		
Utah Gadsby Repower	$827	$70	9.04%	81.09	2.13	85%	11.18	200.2	235.2	11.85	0.31	23.34
Utah Cogen 2	$831	$45	9.04%	79.19	5.34	85%	11.35	200.2	235.2	14.58	0.53	26.47
OWC Cogen 2	$707	$45	9.04%	67.98	5.34	85%	9.85	226.0	261.0	16.18	0.53	26.56
OWC Cogen 1	$1,174		9.04%	106.13	5.34	85%	14.97	226.0	261.0	11.22	0.53	26.72
Utah Cogen 1	$1,380		9.04%	124.75	5.34	85%	17.47	200.2	235.2	10.11	0.53	28.12
Utah Combined Cycle	$770	$75	9.04%	76.39	10.67	85%	11.69	200.2	235.2	16.86	1.57	30.12
OWC Combined Cycle	$657	$45	9.04%	63.46	10.67	85%	35% 9.96	226.0	261.0	65% 18.71	1.57	30.23
Wyo Combined Cycle	$832	$75	9.04%	81.99	10.67	85%	12.44	200.2	235.2	16.86	1.57	30.87
Utah PC Hunter 4 $20/Ton	$1,483	$50	8.37%	128.31	32.39	85%	21.58	91.8	100.1	9.59	0.45	31.62
Wyo PC Wyodak 2	$1,527	$510	8.37%	170.50	32.39	85%	27.25	39.8	41.1	4.65	0.45	32.35
Wyo Coal $6.70/Ton	$1,735	$510	8.37%	187.91	32.39	85%	29.59	41.0	42.4	4.34	0.45	34.38
Utah IGCC Hunter 4	$1,735	$50	9.04%	161.36	30.35	85%	25.75	91.8	100.1	7.99	2.13	35.86
Utah Coal $23.25/Ton	$1,694	$130	8.37%	152.67	32.39	85%	24.85	106.7	116.3	11.15	0.45	36.45
Wyo IGCC Wyodak 2	$1,710	$510	9.04%	200.69	30.35	85%	31.03	39.8	41.1	3.28	2.13	36.44
Wyo IGCC CT	$1,710	$510	9.04%	200.69	30.35	85%	31.03	41.0	42.4	3.38	2.13	36.54
Utah IGCC CT	$1,735	$130	9.04%	168.60	30.35	85%	26.72	106.7	116.3	9.28	2.13	38.13
Utah Coal $27.00/Ton	$1,694	$130	8.37%	152.67	32.39	85%	24.85	123.9	135.1	12.95	0.45	38.25
Utah Wind Non-firm	$1,000	$75	5.56%	59.77	60.84	36%	38.78	0.0				38.78
Wyo Wind Non-firm	$1,000	$75	5.56%	59.77	60.84	36%	38.78	0.0				38.78
OWC Geothermal	$2,145	$75	9.60%	213.12	15.00	90%	28.93	107.3	107.3	10.73	2.00	41.66
Utah Geothermal	$2,145	$75	9.60%	213.12	15.00	90%	28.93	107.3	107.3	10.73	2.00	41.66
Utah Wind Firm	$1,000	$360	6.56%	89.22	60.84	36%	48.25	0.0				48.25
Wyo Wind Firm	$1,000	$365	6.57%	89.68	60.84	36%	48.40	0.0				48.40
OWC Wind Non-Firm	$1,000	$75	6.57%	70.63	50.00	28%	49.18	0.0				49.18
OWC Wind Firm	$1,000	$220	7.36%	89.79	50.00	28%	56.99	0.0				56.99
Utah Simple Cycle CT	$549	$75	9.29%	57.97	22.58	15%	61.30	184.7	219.7	23.19	3.73	88.22
Wyo Simple Cycle CT	$594	$75	9.29%	62.10	22.58	15%	64.45	184.7	219.7	23.19	3.73	91.37
OWC Simple Cycle CT	$467	$45	9.29%	47.56	36.98	15%	64.34	190.9	225.9	23.85	3.73	91.92
OWC Bridger Trans L		$1,240	8.37%	103.79		100%	11.85	97.1	97.1	8.59		20.44
OWC Htr/OWC Trans L		$1,240	8.37%	103.79		100%	11.85	104.1	104.1	9.56		21.40
OWC Pump Storage	$800	$75	8.16%	71.40	13.00	30%	32.12	0.0				32.12
Utah Compressed Air	$675	$360	8.16%	84.46	4.32	30%	33.78	200.2	235.2	11.06	1.10	45.94
Utah Pumped Storage	$785	$75	8.16%	70.18	13.00	30%	31.65	0.0				31.65

incremental 29.94 avg heat rate

ljh N3.19/20 Potential Noncost ++ -

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Tables 3-19 and 3-20 show the non-cost characteristics and cost components of the supply-side resources considered by the model, listed from lowest total resource cost (TRC) to highest TRC. Because of the substantial cost differences between major technology groups, listing by TRC results in the following natural order: first, gas-fired technologies; second, coal-fired technologies; third, renewable technologies; and finally peaking options. This sorting is a good preview of what the model will select: gas-fired resources. Transmission geographic conversion and pumped storage are at the bottom of the table to reflect the special characteristics of these resource options. The discussion of the transmission cases in Chapter 5 explains the transmission geographic conversion.

Table 3-19 begins with non-cost characteristics. The first three columns provide information about the amount of each resource. "MW Available in 1st Year or Plant Size" is the size plant typically available for that technology. However, the model selected the exact amount of resource required to meet its reserve margin requirement each year. For example, it would add 32 MW of a gas-fired plant if that amount would meet the reserve margin requirement. Therefore the typical size of resources did not affect modeling. One sensitivity added resources only in large amounts reflecting the amounts in this column. The next column, "1st Year Available" reflects the lead time required for each technology. Thus if the first year available is 2000, then the lead time is four years from 1996. The column "Maximum MWa Available," indicates the maximum amount of each resource available during the entire 20-year study period. Although some resources have "unlimited" in this column, the company recognizes that costs will vary. The first few plants will take the best sites with the lowest costs, and subsequent developments will have increasing costs. "Depreciation Life" is the number of years over which the company would depreciate the capital cost of the resource. "Tax Life" is the number of years over which the company would apply depreciation for tax purposes. "Heat Rate -- Incremental" is the heat rate once the machine is in operation. "Heat Rate -- Average" is the heat rate averaged over all hours of expected operation. The model uses the incremental heat rate to calculate anticipated fuel cost. The table's calculations, and emission calculations, use average heat rate. The next two columns provide emission rates in lbs/MMbtu for NOx and CO_2.

incremental also

Conversion from MMBtu's -> kWh in tables uses incremental heat rate

Table 3-20 shows the costs for each resource technology. The first four columns deal with capital costs. "Unit Cost" is the cost per kW for the equipment, including engineering, site preparation, taxes, AFUDC, and other capitalized costs. "Transmission" is the capital cost required to connect the new resource to the existing transmission system. It does not include any system upgrade costs. "Payment Factor" is the real levelization factor that converts capital cost into a first-year payment. "Annual Payment" is the result of multiplying the amounts in the "Unit Cost" and "Transmission" columns by the percentage in the "Payment Factor" column. The next four columns arrive at the "Ttl Capital & Fixed Cost" in mills/kWh by adding the fixed O&M to the "Annual Payment" amount, and converting the sum to mills/kWh using the "Expected Utilization Rate."

The calculation of a real levelized cost for this table uses an assumed utilization rate. That cost was calculated for this table but was never input into the model. The inputs to the model are the individual cost components. The utilization rate in this column of the table may or may not accurately reflect the model's use of each resource, but it is close to what has occurred. The formula to calculate mills/kWh is the amount in the "Ttl Capital & Fixed Cost" column times 1000, all divided by 8760 (the number of hours in a year), and then divided by the percentage in the "Expected Utilization Rate" column. For example, for Gadsby repowering the calculation is
((($81.09 + $2.13) x 1000)/8760)/85% = 11.18 mills/kWh.

The "Energy Cost in 2003" columns begins with "1st Year" to show the cost of fuel in the year 2003, because this is the first year that the company needs new baseload resources under medium load growth assumptions. IPM uses the fuel price for each year, not just 2003. The middle of these three columns "Levelized cent/MMbtu" shows the real levelized cost of fuel for the unit from 2003 to 2045. IPM calculates a number similar to this before making its resource selections. The "Levelized Mills/kWh" column converts the real levelized cost into mills/kWh. The next column, "Variable O&M" is the cost of operation and maintenance that varies with the operation of the unit. The last column, "Total Resource Cost," shows the 2003 real levelized cost in 1996 dollars (including fuel escalation to 2003). It is the sum of the fixed costs in mills/kWh, energy cost, and variable O&M cost.

by taking
cents/MMBtu /1,000,000
* by inc. heat rate

Table 3-21 compares the capital cost for supply-side resources in RAMPP-4 versus RAMPP-3. The last column shows the difference in 1996 dollars. A negative number signifies that the RAMPP-3 cost was higher than the RAMPP-4 cost. This shows that, in general, new

Resource Costs for RAMPP-4 vs. RAMPP-3
Unit Capital Cost in $/kW

Table 3-21

Potential Resource	RAMPP-3 (1994 $)	RAMPP-4 (1996 $)	Difference * (1996$)
OWC Cogen 1	1100	1174	0
OWC Gas Fired			0
Cogen 2	663	707	0
Combined Cycle	687	657	-76
Simple Cycle CT	479	467	-44
OWC Geothermal	2076	2145	-70
OWC Pump Storage	800	800	-54
OWC Wind	1120	1000	-195
Utah Cogen 1	1293	1380	0
Utah Gas Fired			0
Cogen 2	779	831	0
Combined Cycle	742	770	-22
Simple Cycle	518	549	-4
Utah IGCC CT	1941	1735	-336
Utah Gadsby Repower	N/A	827	0
Utah FB Coal	2454	N/A	0
Utah PC Hunter 4		1483	1483
Utah Coal	1795	1694	-221
Utah Geothermal	2076	2145	-70
Utah Compressed Air	N/A	675	0
Utah Pumped Storage	800	785	-69
Utah Solar	4283	N/A	0
Utah Wind Firm	1150	1000	-227
Wyo Gas Fired			0
Combined Cycle	819	832	-42
Simple Cycle CT	571	593.5	-16
Wyo IGCC CT	2035	1710	-461
Wyo FB Coal	2354.5	N/A	0
Wyo PC Wyodak 2	N/A	1527	0
Wyo Coal	1942	1735	-337
Wyo Wind	1150	1000	-227

* (R-4-(R-3x1.067)=Difference

resource costs came down between RAMPP-3 and RAMPP-4. If the capital cost for a resource increased only by the amount of inflation, there is no difference in 1996 dollars between RAMPP-3 and RAMPP-4. The large difference shown in the cost of new coal at the Hunter site is only because Hunter was not separately identified in RAMPP-3.

Gas-Fired Resources

Gas-fired resources included repowering the Gadsby plant in Utah, cogeneration, and combined cycle combustion turbines. Repowering Gadsby is the lowest cost alternative in the portfolio, with a real levelized cost of about 23 mills/kWh. Gadsby is the least-cost choice in the portfolio, followed by the other gas-fired resource choices. The portfolio includes four cogeneration choices: Cogen 1 and Cogen 2 in both the OWC and Utah areas. Cogen 1 represents units with higher capital costs and lower heat rates than Cogen 2. Cogen 1 assumes a high percentage of thermal matching. Cogen 2 assumes varying amounts of process steam extraction from the steam portion of the cycle. The process steam usage is the distinguishing difference between Cogen 2 and the non-cogeneration gas-fired units. The portfolio table shows Cogen 1 and Cogen 2 available in the OWC and Utah areas at about 26 to 28 mills/kWh.

The portfolio included combined cycle combustion turbine (CCCT) technology in each of three areas: Utah, OWC, and Wyoming. CCCT technology is mature and commercially available from a variety of vendors. It is appropriate for baseload and intermediate loads. The CCCT can respond quickly to short-term load requirements. The portfolio table 3-19 shows combined cycle technology with real levelized costs of about 30 to 31 mills/kWh.

Coal-Fired Resources

Coal-fired resources include pulverized plants and integrated gasification combined cycle (IGCC) plants in the Utah and Wyoming areas, where inexpensive coal is available. The portfolio table includes nine entries for coal. Three are pulverized coal units in Utah: one using $20/ton coal at Hunter 4, one with $23.25/ton coal at a generic site, and one with $27/ton coal at a generic site. Two are integrated gasification combined cycle (IGCC) units in Utah: one at Hunter 4 and one at a generic site. Two are pulverized coal units in Wyoming: at Wyodak 2 and at a generic site using $6.70/ton coal. Two are IGCC units in Wyoming: one at Wyodak 2 and one at a generic site. The real levelized cost of coal-based resources varied between about 32 and 38 mills/kWh.

The costs for the pulverized coal units included selective catalytic reduction (SCR) equipment. As recently as two years ago, most experts in the field believed that SCR would increase the total O&M cost of a pulverized coal unit by about 25 percent. Recent experience of other utilities suggests that SCR technology would increase total O&M by only about 10 percent, with costs split evenly between fixed and variable O&M. For the plants in the RAMPP-4 portfolio, this was an increase in O&M over a plant without SCR of approximately 0.44 mills/kWh. Inclusion of SCR technology in a proposed pulverized coal unit would probably not reduce permitting time. SCR is likely to be the BACT (best available containment technology) and thus future environmental regulations might require it.

The RAMPP-3 action plan included a study on clean coal technologies. The RAG group received a report on that study and reviewed it at the December 1994 RAG meeting. Based on the study, PacifiCorp concluded that the total cost of electricity from integrated gasification combined cycle (IGCC) plants is beginning to be competitive with the cost of conventional pulverized coal (PC) plants that have flue gas desulfurization (FGD) and selective catalytic reduction (SCR) equipment. Improvements in the next five to ten years in gas turbine efficiencies should further reduce the cost of electricity from IGCC plants compared to conventional PC/FGD/SCR plants. The emissions from IGCCs approach those from natural gas plants, which should make permitting easier. The commercialization of fluidized bed technology is a number of years behind IGCC. Fluidized bed technology also does not have emissions performance or efficiencies equal to IGCC.

<u>Renewable Resources</u>

Renewable resources in RAMPP-4 included wind and geothermal. The portfolio did not include solar resources because their costs are not competitive with wind and geothermal. The model would not select solar resources, even with high externality costs on all the non-renewable resources.

The portfolio included six entries for wind: OWC non-firm, Utah non-firm, Wyoming non-firm, OWC firm, Utah firm, and Wyoming firm. Non-firm wind relies on existing transmission lines, which are often fully loaded. When the existing lines are fully loaded, there is no opportunity to move the wind power out of the area, which is why it is non-firm. Firm wind includes the costs to add sufficient transmission to create a firm path for the power. Firm wind resources have a higher capital cost than non-firm wind for transmission connections. The real levelized cost of wind resources varied between about 39 and 57 mills/kWh. The wind costs included the federal tax credit of 1.5 cents per kWh for each kWh generated during the first 10 years of wind operation, if the plant is on-line by July 1, 1999.

The cost of the transmission line addition needed to provide firm wind power varies by location, from \$220/kW in OWC to \$365/kW in Wyoming. The amount of transmission added to the wind resource cost is only the amount needed for the capacity of the particular wind plant. That amount could be lower, to an amount closer to the average level of wind output. This would remove some of the energy available to the system. The company did not analyze the trade-offs involved in lowering the level of transmission capacity.

In RAMPP-3 the company calculated the reserve margin contribution as 90 percent of the average annual generation for wind plants. In RAMPP-4 the company calculated the reserve margin for winter and summer as 90 percent of the average generation in that season. Wind generation varies widely between season. Using a seasonal specific reserve margin calculation more accurately estimates the value of the wind resource for the system.

The second major renewable technology is geothermal. Geothermal resources are available in the OWC and Utah areas at about 42 mills/kWh. Geothermal is highly site specific and only a limited number of sites are available.

<u>Peaking Resources</u>

Peaking resources in the portfolio included a summer purchase, simple cycle combustion turbines (SCCTs), pumped storage in Utah and OWC, and compressed air. SCCT technology is mature and commercially available from a variety of vendors. SCCTs have low capital costs and can respond easily to fluctuations in electrical load. Their high heat rate requires more fuel to create a kWh than a combined cycle, so SCCTs are most appropriate for peaking needs. The portfolio included SCCTs in the OWC, Utah, and Wyoming areas at costs of about 91 to 96 mills/kWh. The high cost per kWh reflects their low capacity factor.

Pumped storage uses low-cost off-peak power to pump water to an upper reservoir. When the utility needs power, it discharges water through a reversible pump turbine to a lower reservoir, producing electricity. A limited number of sites are available for pumped storage, and the costs are very site specific. Estimated costs are in the 32 mills/kWh area, assuming a 30 percent utilization rate. Compressed air uses a similar process. An underground cavern stores the compressed air. The compressed air reduces the amount of gas needed to fire a combustion turbine to produce electricity when the utility needs power. The costs for compressed air technology are higher than pumped storage, at about 46 mills/kWh.

PacifiCorp usually does not include purchased power in its RAMPP analysis because of the difficulty predicting prices, availability and terms. However, the increasingly competitive marketplace has made it easier to forecast the availability and price of seasonal peaking services for the next few years. Until the company needs resources to meet both summer and winter needs, the most cost-effective way to meet summer peaking needs alone is to contract for peaking services for the few months when needed. Since PacifiCorp will only need summer peaking resources for one year before it needs resources year round, and since those services are available in the marketplace, the portfolio includes the temporary purchase of summer peaking resources. Summer-season capacity is available at $2/kW month, or $6/kW season.

<u>Fuel Cells</u>

The large central generation facility has traditionally been the economically preferred generation source for utilities. However the risk associated with construction of large generating units, the environmental risks of some technologies, and the financial costs of transmission may make small distributed generation resources more economically attractive. At this time, their prices are not competitive with other supply-side choices, so they are not in the portfolio. However, the company decided to include a brief discussion of its investigation of this future potential source of power.

Fuel cells offer many benefits that make them a good distributed generation resource. These benefits include high efficiency, very low emissions, low noise, minimal water requirements and modular construction. Four fuel cell technologies show the most promise for distributed generation service: phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC), solid oxide fuel cells (SOFC), and proton exchange membrane fuel cells (PEM). The PAFC is presently the only fuel cell that is commercially available. Its price is about $3,000/kW. The other fuel cell technologies are in their demonstration phases with projected commercialization dates after 1998.

There are other technologies available for distributed generation applications: small gas turbines and internal combustion engines in sizes ranging from 200 kW to 30 MW. Currently at the 30 MW size fuel cells have a higher cost of energy than the gas turbine options. In the smaller size applications (less than 2 MW) the fuel cells are very competitive with gas turbines. However, all of these choices are significantly more expensive than a combined cycle CT or cogeneration project. PacifiCorp will continue to watch fuel cell technologies as well as other technologies available to broaden the energy choices available to customers.

Transmission Costs

The total cost for each of the supply-side resources in the portfolio included the additional transmission facilities needed to connect the resource to the local grid. It did not include the costs of upgrading the backbone transmission system to expand its capacity to transmit power between geographic areas. The transmission capital costs for connecting each resource to the local grid assumed a certain distance from the nearest transmission line, shown on Table 3-22. The transmission costs vary from $0 to $510/kW, depending on the resource technology and its location.

The transmission costs for connecting a new resource used the anticipated miles of new line required, which ranged from zero to 300 miles. RAMPP-3 used $60/kW for the interconnection transmission cost for all gas-fired and coal-fired resources. RAMPP-4 refined that considerably. Both assigned zero cost for cogeneration at a site already served by PacifiCorp. The transmission cost for other gas-fired

Transmission Integration Cost ($1996)

Table 3-22

	Project	Project Size (KW)	Miles New Line	Regional Service (Costs to serve loads) (within the region) ($)	($/KW)	Inter-Regional Service (Incremental costs to serve) (loads in other Regions) ($)	($/KW)
OWC	**Specific Sites**						
	Cogen #1				0	$1,240,000,000	1,240
	Generic Estimates					for 1000 MW	
	Cogen #2	200,000	10	$9,000,000	45		
	Simple Cycle	200,000	10	$9,000,000	45		
	Combined Cycle	200,000	10	$9,000,000	45		
	Geothermal	200,000	25	$15,000,000	75		
	Pumped Storage	200,000	25	$15,000,000	75		
	Wind Non-Firm	200,000	25	$15,000,000	75		
	Wind Firm	300,000	125	$66,000,000	220		
UTAH	**Specific Sites**						
	Hunter #4 Pulv Coal	440,000	0	$22,000,000	50	$1,240,000,000	1,240
	Hunter #5, 6, 7, 8...	440,000	35	$57,200,000	130	for 1000 MW	
	Hunter #4, IGCC	240,000	0	$12,000,000	50		
	Other Utah IGCC	240,000	35	$31,200,000	130		
	Gadsby Repowering	370,000	0	$25,900,000	70		
	Cogen #1				0		
	Generic Estimates						
	Cogen #2	200,000	10	$9,000,000	45		
	Simple Cycle	200,000	25	$15,000,000	75		
	Combined Cycle	200,000	25	$15,000,000	75		
	Geothermal	200,000	25	$15,000,000	75		
	Pumped Storage	200,000	25	$15,000,000	75		
	Compressed Air	200,000	25	$72,000,000	360		
	Wind Non-Firm	200,000	25	$15,000,000	75		
	Wind Firm	300,000	225	$108,000,000	360		
WYOMING	**Specific Sites**						
	Wyodak #2, Pulv Coal	260,000	300	$132,600,000	510	$74,100,000	285
	Wyodak #2, IGCC	260,000	300	$132,600,000	510	for 200 miles	
	Other Wyoming Pulv Coal	260,000	300	$132,600,000	510	for 260mw	
	Other Wyoming IGCC	260,000	300	$132,600,000	510	Wyo to Utah	
	Generic Estimates						
	Simple Cycle CT	200,000	25	$15,000,000	75		
	Combined Cycle CT	200,000	25	$15,000,000	75		
	Wind Non-Firm	200,000	25	$15,000,000	75		
	Wind Firm	300,000	175	$109,500,000	365		

RAMPP-3 to RAMPP-4 Comparisons
Supply-Side Portfolio Transmission Costs

Table 3-23

Potential Resource	RAMPP-3 (1994 $kW)	RAMPP-4 (1996 $/kW)	Difference * (1996 $/kW)
OWC Cogen 1	0	0	0
OWC Gas Fired	60	45	-19
OWC Geothermal	120	75	-53
OWC Pump Storage	0	75	75
OWC Wind Non-Firm	N/A	75	0
OWC Wind Firm	120	220	92
Utah Cogen 1	0	0	0
Utah Gas Fired	60	75	11
Utah Coal Hunter 4	60	50	-14
Utah Coal Beyond Hunter 4	60	130	66
Utah Gadsby Repower	N/A	70	0
Utah Geothermal	120	75	-53
Utah Compressed Air	N/A	360	0
Utah Pumped Storage	0	75	75
Utah Solar	120	N/A	0
Utah Wind Non-firm	N/A	75	0
Utah Wind Firm	212	360	134
Wyo Gas Fired	60	75	11
Wyo Coal	60	510	446
Wyo Wind Non-firm	212	75	-151
* (R-4-(R-3x1.067)=Difference			

resources varied between $45 and $75/kW, depending on the proximity of the resource to existing transmission lines. Coal-fired resources in RAMPP-4 had either a $50/kW transmission cost (Hunter 4), $130/kW (Utah coal at a generic site), or $510/kW (Wyoming coal). Wyoming has few transmission lines. New resources there require substantially more investment to connect to the grid.

Renewable resources had a RAMPP-3 transmission cost of either $120 or $212/kW, depending on location. RAMPP-4 used $75/kW except for $220/kW transmission cost for OWC non-firm wind, $360/kW for Utah firm wind, and $365 for Wyoming firm wind. Wind farms in Utah and Wyoming would require more transmission lines to connect them to the grid. RAMPP-3 applied no transmission cost for pumped storage. However, such resources would require transmission investment. RAMPP-4 used $75/kW for the required transmission equipment.

Table 3-23 compares the transmission costs for adding new resources in RAMPP-3 and RAMPP-4.

The RAMPP-4 analysis included two sensitivities that increased the capacity of the system as well as the associated cost for the transmission upgrades. Expanding capacity out of the Utah area to OWC would cost about $1,240/kW; expanding capacity out of Bridger to OWC would cost about $575/kW.

Non-Firm Markets

The model recognizes PacifiCorp's buying and selling activity in the non-firm markets by assuming access to three regionally diverse wholesale markets. These three markets are the Pacific Northwest, the Desert Southwest (Utah, Four Corners and Palo Verde inter-connections), and California (through the North-South Intertie). Although the California market has a large capacity, transmission constraints severely restrict market access.

☆ Non-firm market activity does not occur in the Bridger or Utah areas. Both purchases and sales can occur in OWC. Purchases but no sales can occur in Wyoming. No purchases can occur in California but the model can sell in that area. The model can make both purchases and

Question: Does DSW include or exclude Utah?

yes

sales in the DSW area. These constraints reflect the company's purchase and sale activity in each of the geographic areas.

The following table shows the amounts of power assumed to be available by geographic area:

Non-Firm Market Amounts in IPM (in MW)
Table 3-24

	Purchases	Sales
OWC On-Peak	350	400
OWC Off-Peak	350	300
California On-Peak		1,000
California Off-Peak		500
Wyoming On-Peak	250	
Wyoming Off-Peak	250	
Desert SW On-Peak	250	200
Desert SW Off-Peak	250	150

PacifiCorp used historical trends for price and power availability in each of the wholesale markets. The escalation of market prices over time correlated 80 percent with the gas price escalation rate for each model run.

In the last year the wholesale market in the West has changed dramatically. The non-firm prices used in RAMPP-4 are considerably lower than they were in RAMPP-3. Power marketers have brought prices down significantly. They have facilitated the flow of power from surplus areas to deficit areas, and have made information more readily available. The western United States has excess power, and as the market for this power becomes more efficient, prices should continue to decline.

RAMPP-4 used a uniform non-firm market price for all geographic areas of 19 mills on-peak and 16 mills off-peak. The company is finding that the advent of competition in the market place has caused a narrowing of seasonal and regional price diversity. Increased sales and transmission access are leveling any price differences across geographic areas and across seasons. Seasonal exchange transactions tend to balance the seasonal demands between winter- and summer-peaking utilities. Increased regional competition has lowered the margin on sales across all regions toward a single average market clearing price. For modeling purposes, the company assumed that seasonal and regional diversity would be non-existent by 1996.

In RAMPP-3 the escalation rate for non-firm prices was 100 percent of the gas escalation rate used for the particular case. In RAMPP-4, only 80 percent of the non-firm price varied with the gas escalation rate. The company discussed this degree of correlation with the public advisory group and arrived at 80 percent as an acceptable level. The three escalation rates for non-firm market prices are a low rate of 0 percent real escalation, a medium of 1.7 percent, and a high of 3.02 percent.

Reserve Requirements

The reserve margin is the difference between a utility's firm resources and its firm load on a capacity basis. RAMPP-3 required the model to add new resources whenever the winter reserve margin fell below 15 percent. RAMPP-4 required the model to add new resources whenever the winter or summer reserve margin fell below 12 percent.

PacifiCorp is part of a very large integrated power system in the West. The reliability of the Western System Coordinating Council (WSCC) is quite high because individual utilities have planned to a high level of reliability. By pooling the generating resources of a number of utilities, the region achieves a more reliable combined system. If one plant fails it has less impact on the entire system. This reduces the individual reserve requirements for participating utilities.

PacifiCorp can easily afford a lower reserve margin. Its system consists of a large number of generating resources that are relatively small. The company's coal plants have some of the lowest forced outage rates in the country. PacifiCorp also has access to diverse markets in the West either through its own transmission or rights the company has purchased. PacifiCorp can therefore tap surpluses that are available from other participants in WSCC. The current reserve margin for WSCC is 24 percent in the summer and 30 percent in the winter. They have a very high capacity surplus. As the industry becomes increasingly competitive, utilities will have a stronger incentive to carry only as much reserve as they really need to provide reliable service.

8.6% discount rate

Discount Rate

The company used its after-tax incremental cost of capital as the discount rate for RAMPP-4. The discount rate is a key component in calculating the real levelized cost of resources. This measure provides a way to compare resources that have different cost structures and different lifetimes. The 10.13 percent discount rate used in RAMPP-4 is the company's incremental weighted cost of capital with the debt component expressed on an after-tax basis. The 10.13 percent rate is slightly less than the 10.43 percent rate in RAMPP-3. The lower rate reflects a reduction in interest rates. It also reflects lower debt and preferred costs because the credit rating agencies upgraded PacifiCorp's first mortgage bonds and preferred stock since RAMPP-3.

Long-run inflation for RAMPP-3 was 3.4 percent, in RAMPP-4 it was 3.3 percent.

To calculate an annual payment on capital costs (the capital carrying charge) for each resource, the company first calculated the year-by-year capital revenue requirements for the particular resource. This included the company's rate of return, recovery of capital (depreciation) and income taxes. The company then determined the present value of this stream of year-by-year revenue requirements using the 10.13 percent discount rate. The next step created another stream of annual payments that increased at the rate of inflation each year but has the same present value as the stream of year-by-year revenue requirements. The company then used the first-year payment from this stream of annual payments as inputs to the IPM model. The ratio of the first-year payment to the present value total is the capital carrying charge. The annual payment varies by resource because of varying book lives and tax treatments.

RAMPP-3 included an analysis of the impact of the discount rate on the ranking of resources in the portfolio. Using a 3 percent real discount rate for the social discount rate made very little difference in the ranking of resources in the portfolio. RAMPP-3 included a sensitivity that calculated the cost of all resources using the social discount rate. This did not cause a noticeable shift in resource selections, and had only minimal impact on system costs. RAMPP-4 did not include a discount rate sensitivity, as it appeared the results would be the same.

+ RR + ... = TAXES

12%

Revisions to Inputs

PacifiCorp determined all of the key inputs to the model in early 1995, and then did the modeling for the 39 cases. Between early 1995 and late 1995 some of those inputs may have changed. This section identifies the changes that have occurred, and how each would affect the modeling results. The following discussion addresses updates in the following areas:

- Existing system: APS CTs
- Existing system: Hermiston
- Existing system: wind plants
- Existing system: plant re-rates
- Existing system: wholesale sales
- New resource: gas prices
- New Resources: renewables
- Non-firm market prices

Existing System: APS CTs

RAMPP-4 modeling included the APS CTs in the existing system beginning in 1998. They were part of the portfolio because they are part of an extensive agreement with Arizona Public Service company that includes many other components. The company is re-evaluating the timing for those CTs, discussing the issue with APS, and now expects delays in the timing of those projects. If the delay is 2-3 years, it would not affect the modeling results that peaking needs don't begin until 2002. Therefore, the company does not believe that this presents a problem for RAMPP-4 model results.

Existing System: Hermiston

As of May 1995, 60 percent of the engineering efforts were complete and 93 percent of the project purchase orders placed for the Hermiston project. PacifiCorp has initiated discussions with U.S. Generating Company regarding potential cost savings that may be available.

Existing System: Wind Plants

Both the Foote Creek and Columbia Hills wind projects are on track for completion and on-line status in 1996. Recent agreements with BPA and Kenetech clear significant hurdles in siting and building the projects. With both projects, PacifiCorp will be the majority owner and Kenetech will be the developer.

The United States House of Representatives Ways and Means Committee's latest budget proposal includes cutting the wind tax credit. PacifiCorp is working to keep the credit in effect. The company appreciates the importance of the credit to keep the current cost of wind power more competitive with alternative power sources. If the budget proposal without the credit is approved, it could threaten the viability of current and new wind projects. The company will be carefully watching the Committee's activities.

Existing System: Plant Re-Rates

Plant re-rates occur on an ongoing basis as plants undergo maintenance. Often different sources will report slightly different capacities; typically this is due to the use of different measurement standards. For example, the measurement may be on potential capacity, on a 30-minute output, or averaged over a longer time period. Any changes since early 1995 are small and would not affect the RAMPP-4 modeling results.

Existing System: Wholesale Sales

The company has made some new wholesale sales since performing the modeling for RAMPP-4. The significant fact for RAMPP modeling is that they all expire before the date of expected resource deficiency (2003), except for one 50 MW sale. New purchases of 71 MW help balance the sale and neutralize its impact on resource needs. Thus, recent wholesale activity should have no impact on the date of the company's need for new resources. Recent sales are listed below:

- City of Anaheim for 25 MW from 5/1995 to 10/1997
- Black Hills Power and Light for up to 60 MW from 10/1996 to 3/2002
- BPA for 100 MW from 8/1995 to 7/1998
- Cheyenne Light Fuel and Power for 145 MW from 6/1997 to 5/2000
- Eugene Water and Electric Board for 50 MW from 8/1995 to 7/2000
- Hinson Power for 140 MW from 4/1996 to 3/2001
- Springfield Utility Board for 50 MW from 10/1995 to 9/2015

In addition, the company has made two new wholesale purchases:

- BPA for 50 MW from 8/1995 to 7/1998
- City of Redding for 21 MW from 5/1995 to 5/2014

Information about the prudency of these contracts will be part of future rate case filings. Until the state public utility commissions decide the transactions are prudent in a rate case, there will be no price impact to customers.

<u>New Resource Costs: Gas Prices</u>

Current gas prices have declined from 155.1 to 124.5 ¢/MMBtu in the Mountain region and 131.6 c/MMBtu in the Pacific Northwest region. The medium gas price escalation rate has declined from 2.11 percent used in RAMPP-4 modeling to about 1.55 percent. Although lower, it is not as low as the low escalation rate used -- zero percent real escalation. However, the starting price has declined by about 19 percent in the Mountain region and by about 15 percent in the Pacific Northwest region. Table 3-25 shows the differences in assumptions used in the RAMPP-4 modeling and current market conditions. Since gas-fired resources were the least-cost supply-side resource under the original assumptions, lowering their cost does not change the ranking of resources.

Comparison between RAMPP-4 Forecast and Current Prices for Natural Gas

Table 3-25

		Current Market	RAMPP-4 Forecast	Difference
Raw Gas Price Including 1.5% Shrinkage				
Low Gas Price	Pacific NW	124.5	151.9	(27.4) ¢/MMBtu
Medium Gas Price	Pacific NW	124.5	155.1	(30.6) ¢/MMBtu
High Gas Price	Pacific NW	124.5	157.6	(33.1) ¢/MMBtu
Low Gas Price	Mountain	131.6	151.9	(20.3) ¢/MMBtu
Medium Gas Price	Mountain	131.6	155.1	(23.5) ¢/MMBtu
High Gas Price	Mountain	131.6	157.6	(26.0) ¢/MMBtu
Transport & Storage				
Simple Cycle (1)	Pacific NW	12.48	35.91	(23.43) /kW-year
	Mountain	19.91	21.51	(1.60) /kW-year
	Pacific NW	10.31	11.40	(1.09) ¢/MMBtu
	Mountain	5.37	5.20	0.17 ¢/MMBtu
Combined Cycle	Pacific NW	35.30	46.50	(11.20) ¢/MMBtu
	Mountain	23.50	20.70	2.80 ¢/MMBtu
Real Gas Price Escalation Rate				
Low Gas Escalation		0.66%	0.00%	0.66% / year
Medium Gas Escalation		1.55%	2.11%	-0.56% / year
High Gas Escalation		2.84%	3.78%	-0.94% / year
Real Transport & Storage Escalation Rate				
		0.00%	0.00%	0.00% / year

(1) Simple Cycle assumes 15% capacity factor. 11,300 BTU/kWh average heat rate.

A comparison between the low gas price case and the base case shows the major impacts of a decrease in the gas price and gas price escalation. Lower gas prices make gas-fired resources cheaper relative to other resources, which would result in the model's selection of more gas-fired resources and less DSM. Many of the DSM bundles would not be cost-effective at a 125 or a 131 ¢/MMbtu gas price. The model would also make fewer non-firm sales, and make more non-firm purchases. In spite of these changes in gas prices, and their expected impacts on modeling results, the company is not changing the amount of DSM in the RAMPP-4 action plan.

Coal prices have shown no significant change since early 1995.

<u>New Resources: Renewables</u>

A recent announcement by PacifiCorp is not directly related to the RAMPP-4 inputs, but is a significant development for the company's knowledge and experience with renewable technologies. PacifiCorp recently announced a joint venture with Bechtel to develop, own, and operate small renewable and distributed energy system projects in international markets as well as in the U.S. EnergyWorks will focus on specific markets for commercially available technologies: wind power, biomass-fueled power and cogeneration, small hydro, hybrid energy systems for remote and distributed power applications such as solar, and industrial energy efficiency services. The World Energy Council projects that approximately 145,000 MW of new electric generating capacity using renewable resources will be added to the global energy supply between 1991 and 2010. The initial focus of EnergyWorks is likely to be selected developing countries where the benefits of grid-supplied power are not readily secured, that have attractive business environments, and where growth in demand for power are greatest. The initiative will work with strong local partners in each country. PacifiCorp sees this type of business arrangement as best addressing customer needs, accelerating the company's understanding of the technology of PV and its economics, and developing the capability to provide such services in the U.S. when a viable business can be sustained.

<u>Non-Firm Market Prices</u>

Wholesale prices have declined slightly since early 1995. The company believes they may be one to two mills lower than the levels used in

13.5 10

RAMPP-4 modeling, or around 18 mills on-peak and 14 mills off-peak. The reader can look at the case with 25 percent lower non-firm market prices for an estimate of the impact of lower non-firm market prices. The primary impact would be lower revenues for the company and higher retail customer prices. It would have very little impact on resource choices.

The company has concluded that, in spite of some changes in inputs since the RAMPP-4 modeling, none of the changes warrant changing the action plan.

The next chapter covers the modeling results for RAMPP-4. It reviews the input assumptions and results for each of the individual cases.

Chapter 4: Modeling Results

This chapter describes the cases and the results. It begins with an explanation of the tables used to present the results, followed by a discussion of each of the cases. The last two sections compare the results from RAMPP-4 to the results from the RAMPP-3 studies and evaluate the results with a risk analysis. The chapter on the RAMPP-4 action plan links results from the modeling to the action plan.

The RAMPP-4 analyses tested the continued applicability of results from RAMPP-3 and examined some issues in new ways. RAMPP-3 included 155 cases, which provided a thorough examination of future uncertainties and ways to stress the model. Another examination that thorough is not necessary so soon after RAMPP-3. The modeling for RAMPP-4 updated the model inputs with new information since RAMPP-3, added two significant modeling changes, and moved the 20-year study period forward by two years. RAMPP-4 included 39 carefully chosen cases. All but two required updating the model with the data described in Chapter 3. The other two cases used RAMPP-3 data.

To help the reader understand the assumptions that are common to some of the cases, compared to the assumptions that vary across cases, the company prepared Table 4-1. It shows how each of the cases included key assumptions.

Presentation of Results

Analysis of results focused on the first 10 years (1996 - 2005) of the 20-year study period. The results for the first 10 years are the most significant because of the changing nature of the electricity market. Changes in the industry will soon make today's planning assumptions out-of-date. Chapter 1 discussed the issue of the time frame for IRP in the Perceptions section.

This chapter's discussion focuses on the winter peak MW amounts, because PacifiCorp's retail system is winter-peaking (the winter peak for the retail load is higher than the summer peak through the planning period). The load forecasting section of the Inputs chapter discussed the company's peaking patterns.

Common Assumptions
Table 4-1

Run Number	Run Description	Summer Season	Turbine Upgrade	With Hermiston	DSM		Load Growth			Gas Price				Non-Firm			Lumpy Resourse	Reg Non-firm Esc.	Rev. Non-firm Esc.	Reg Transmission	Rev. Transmission	Reg Cost Renew.	Low Cost Renew.	Revised End effects	Enviroment Adders
					Standard DSM	Revised DSM	Med Low	Medium	Med high	Low	Medium	Limited Gas	high	Low Price	Medium Price	High Price									
1	Med Load - Med Gas	X	X	X	X			X			X				X			X		X		X			
4	No Summer Season		X	X	X			X			X				X			X		X		X			
5	No Turbine Upgrades	X		X	X			X			X				X			X		X		X			
6	Without Hermiston	X	X		X			X			X				X			X		X		X			
7	Med Load - High Gas Without Hermiston	X	X		X			X			X				X			X		X		X			
11	No DSM	X	X	X		X		X			X				X			X		X		X			
12	20% Conservation Advantage	X	X	X		X		X			X				X			X		X		X			
13	15% Conservation Advantage	X	X	X		X		X			X				X			X		X		X			
14	15% Conservation Disadvantage	X	X	X		X		X			X				X			X		X		X			
21	Med Low Load - Med Gas	X	X	X	X		X				X				X			X		X		X			
22	Med High Load - Med Gas	X	X	X	X				X		X				X			X		X		X			
31	Med Load - Low Gas	X	X	X	X			X		X				X				X		X		X			
32	Limited Gas (500 MW) at Med Esc	X	X	X	X			X				X				X		X		X		X			
33	Med Load - High Gas	X	X	X	X			X					X			X		X		X		X			
34	Med Load - High Gas Medium Non-Firm Market Prices	X	X	X	X			X					X		X			X		X		X			
41	Resource Lumpiness	X	X	X	X			X			X				X		X	X		X		X			
42	25% Lower Non-Firm Market Prices	X	X	X	X			X			X				X				X	X		X			
43	25% Higher Non-Firm Market Prices	X	X	X	X			X			X				X				X	X		X			
44	250 MW Plant in 1999 25% Lower Non-Firm Market Prices	X	X	X	X			X			X			X					X	X		X			
45	250 MW Plant in 1999 Medium Non-Firm Market Prices	X	X	X	X			X			X				X			X		X		X			
46	250 MW Plant in 1999 25% Higher Non-Firm Market Prices	X	X	X	X			X			X					X			X	X		X			
47	500 MW Plant in 1999 25% Lower Non-Firm Market Prices	X	X	X	X			X			X			X					X	X		X			
48	500 MW Plant in 1999 Medium Non-Firm Market Prices	X	X	X	X			X			X				X			X		X		X			
49	500 MW Plant in 1999 25% Higher Non-Firm Market Prices	X	X	X	X			X			X					X			X	X		X			
50	Underbuild 25% Lower Non-Firm Market Prices	X	X	X	X			X			X			X					X	X		X			
51	Underbuild Medium Non-Firm Market Prices	X	X	X	X			X			X				X			X		X		X			
52	Underbuild 25% Higher Non-Firm Market Prices	X	X	X	X			X			X					X			X	X		X			
57	Test of Transmission Plant Conversion	X	X	X	X			X			X				X			X			X	X			
58	Added Transmission Bridger to OWC	X	X	X	X			X			X				X			X			X	X			
59	Added Transmission Utah to OWC	X	X	X	X			X			X				X			X			X	X			
61	Renewables at 35% of Capital Cost	X	X	X	X			X			X				X			X		X			X		
65	Extension of all Existing Firm Wholesale Contracts	X	X	X	X			X			X				X			X		X		X		X	
66	Extension of Loads & DSM to 2045	X	X	X	X			X			X				X			X		X		X		X	
67	Extension of All Modeling to 2045	X	X	X	X			X			X				X			X		X		X		X	
71	Low Environmental Adders	X	X	X	X			X			X				X			X		X		X			X
72	Medium Environmental Adders	X	X	X	X			X			X				X			X		X		X			X
73	High Environmental Adders	X	X	X	X			X			X				X			X		X		X			X

Table 4-2 shows key results for each of the cases. It covers eight pages: two pages for each of four sets of cases. The table provides results for each of the cases according to 1) summer peak MW added by 2005, 2) winter peak MW added by 2005, 3) annual energy in 2005, 4) average annual emissions, and 5) financial results. The first page of the table for each set of cases shows resources added by the year 2005 for both summer peak capacity and winter peak capacity. The amount of MW varies by season because certain resources, especially gas-fired, have a higher output in winter when average temperatures are lower. The second page of the table for each set of cases shows resources added by 2005 in energy, average emissions, and financial results.

The first page of the table begins with native load, which comes directly from the load forecast for the year 2005. It then adds firm sales, and subtracts the amount of DSM added by the model for that case. The remainder is the total requirement to be met from supply-side resources. Table 4-2 presents the DSM as a subtraction from system needs merely as a convenient way to represent it. The model adds DSM in an integrated process that minimizes total costs for the entire system. Lines 5 and 21 of the table show the amount of capacity provided by the existing system for each of the cases. Lines 6 and 22 show firm purchases, which are the same for almost all of the cases. Lines 8 through 13 and lines 24 through 29 show the actual new resources added by the model. The table lists them under the categories of renewables, cogeneration, combined cycle CTs, coal, transmission, and peaking resources. Lines 15, 16, 31, and 32 show the reserves and the reserve margin requirement for the system.

Table 5-1 in the draft report (now renumbered 4-2) used a technique for reporting the Gadsby repowering that resulted in larger amounts in the new resource category of "Combined Cycle CT" and less in the "Existing Generation" category. Under the older reporting technique, when the model selected the Gadsby repowering, it reduced existing generation by the amount of the original Gadsby MW, and added to the new resource category the original Gadsby MW as well as the incremental Gadsby MW. Table 4-2 in this report, all of the numbers derived from that table, and all of the tables in the Appendix now rely on the newer technique. This change did not affect the financial results, only the reporting of MW additions. The change affects the lines showing "Existing Generation" and the lines showing "Combined Cycle CT" on Table 4-2.

- Now just adds incremental?

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 1 of 8

#	Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant		No DSM Allowed	DSM Costs		
							Med Gas	High Gas		Reduced by 20%	Reduced by 15%	Increased 15%
	Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load	8,807				8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485				1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM	(352)				(358)	(359)	(400)	0	(450)	(436)	(297)
4	**Total Requirements**	**9,940**				**9,934**	**9,933**	**9,892**	**10,292**	**9,842**	**9,856**	**9,995**
5	Existing Generation	10,123				9,974	9,689	9,689	10,123	10,122	10,122	10,123
6	Firm Purchases	424				424	424	424	424	424	424	424
7	New Resources											
8	Renewable	0				0	0	0	0	0	0	0
9	Cogeneration	363				431	715	966	683	371	382	351
10	Combined Cycle CT	222				297	297	0	297	105	110	297
11	Coal	0				0	0	0	0	0	0	0
12	Transmission	0				0	0	0	0	0	0	0
13	Peaking Resources	0				0	0	0	0	0	0	0
14	**Total Resources**	**11,132**				**11,126**	**11,125**	**11,079**	**11,527**	**11,022**	**11,038**	**11,195**
15	Reserves	1,192				1,192	1,192	1,187	1,235	1,180	1,182	1,200
16	Reserve Margin (RM) (%)	12.0				12.0	12.0	12.0	12.0	12.0	12.0	12.0
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load	9,104	9,273	9,273	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	1,195	1,195	995	995	995	995	995	995	995	995
19	less DSM	(446)	(608)	(616)	(445)	(453)	(455)	(487)	0	(529)	(515)	(387)
20	**Total Requirements**	**9,653**	**9,860**	**9,852**	**9,654**	**9,646**	**9,645**	**9,612**	**10,099**	**9,570**	**9,584**	**9,712**
21	Existing Generation	10,162	10,054	10,054	10,161	10,012	9,669	9,669	10,161	10,161	10,161	10,161
22	Firm Purchases	319	317	317	319	319	319	319	319	319	319	319
23	New Resources											
24	Renewable	0	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	387	0	0	104	458	760	1,028	726	395	406	373
26	Combined Cycle CT	248	0	0	229	331	331	0	331	117	123	331
27	Coal	0	721	698	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	247	262	0	0	0	0	0	0	0	0
30	**Total Resources**	**11,115**	**11,340**	**11,331**	**10,813**	**11,120**	**11,079**	**11,016**	**11,538**	**10,992**	**11,009**	**11,184**
31	Reserves	1,462	1,480	1,479	1,159	1,474	1,435	1,404	1,439	1,422	1,426	1,472
32	Reserve Margin (RM) (%)	15.1	15.0	15.0	12.0	15.3	14.9	14.6	14.2	14.9	14.9	15.2

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 2 of 8

	Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant: Med Gas	No Hermiston Plant: High Gas	No DSM Allowed	DSM Costs Reduced by 20%	DSM Costs Reduced by 15%	DSM Costs Increased 15%
	Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Annual Energy in Year 2005 (MWa)											
1	Native Load	6,463	6,634	6,634	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	376	383	305	305	305	299	305	305	305	305
3	Firm Sales	1,266	1,410	1,410	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	512	507	691	957	914	931	1,020	884	889	937
5	less DSM	(244)	(348)	(351)	(200)	(250)	(251)	(272)	0	(299)	(291)	(196)
6	**Total Requirements**	8,710	8,584	8,583	8,524	8,741	8,696	8,686	9,053	8,618	8,631	8,775
7	Existing Generation	7,768	7,473	7,476	7,809	7,672	7,351	7,313	7,760	7,746	7,746	7,787
8	Firm Purchases	400	364	364	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	47	44	46	0	5	22	0	18	15	4
10	New Resources											
11	Renewable	0	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	0	0	97	426	707	951	676	367	378	347
13	Combined Cycle CT	183	0	0	172	242	233	0	217	88	92	237
14	Coal	0	661	639	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	55	59	0	0	0	0	0	0	0	0
17	**Total Resources**	8,710	8,599	8,582	8,524	8,741	8,696	8,686	9,053	8,618	8,631	8,775
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO_2	55,189			55,577	54,430	55,104	55,413	#N/A	55,094	55,118	55,315
19	NO_x	125			125	123	125	126	#N/A	125	125	125
	Financial Results with End Effects to 2045											
20	50-year Utility Cost											
21	NPV at 8.6% (million $)	42,560			42,284	42,610	43,273	43,620	43,471	42,564	42,571	42,578
22	Real Levelized (mills/kWh)	42.55			41.98	42.64	43.31	43.86	41.52	43.00	42.96	42.17
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	42,990			42,610	43,052	43,716	44,158	43,471	43,259	43,225	42,905
25	Real Levelized (mills/kWh)	41.07			40.70	41.12	41.76	42.18	41.52	41.32	41.29	40.98
25	**IPM Obj Function (millions $)**	19,164			18,930	19,390	19,485	19,579	19,620	18,923	18,998	19,307

(A) Case 2 and 3 are RAMPP-3 models. Since these models did not have a 2005 run year, 2003 is presented. Therefore these two cases should only be compared against each other.

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 3 of 8

	Case Name	Base Case Study	Load Growth Rate Medium Low	Load Growth Rate Medium High	Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices High	High Gas Price Non-firm Prices Med	Lumped Resource Additions	Non-Firm Prices Lower by 25%	Non-Firm Prices Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Summer Peak Capacity in Year 2005 (MW)										
1	Native Load	8,807	7,597	10,117	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM	(352)	(112)	(505)	(303)	(392)	(400)	(435)	(367)	(347)	(355)
4	**Total Requirements**	**9,940**	**8,970**	**11,097**	**9,989**	**9,900**	**9,892**	**9,857**	**9,925**	**9,945**	**9,937**
5	Existing Generation	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123
6	Firm Purchases	424	424	424	424	424	424	424	424	424	424
7	New Resources										
8	Renewable	0	0	0	0	0	0	0	0	0	0
9	Cogeneration	363	0	1,584	344	541	532	493	301	294	340
10	Combined Cycle CT	222	0	297	297	0	0	0	297	297	243
11	Coal	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	0	0	0	0	0	0
14	**Total Resources**	**11,132**	**10,547**	**12,429**	**11,188**	**11,088**	**11,079**	**11,040**	**11,145**	**11,138**	**11,130**
15	Reserves	1,192	1,577	1,332	1,199	1,188	1,187	1,183	1,220	1,194	1,193
16	Reserve Margin (RM) (%)	12.0	17.6	12.0	12.0	12.0	12.0	12.0	12.3	12.0	12.0
	Winter Peak Capacity in Year 2005 (MW)										
17	Native Load	9,104	7,895	10,473	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	995	995	995	995	995	995	995	995	995
19	less DSM	(446)	(131)	(619)	(394)	(482)	(487)	(514)	(460)	(438)	(450)
20	**Total Requirements**	**9,653**	**8,759**	**10,849**	**9,705**	**9,617**	**9,612**	**9,585**	**9,640**	**9,661**	**9,649**
21	Existing Generation	10,162	10,161	10,161	10,161	10,161	10,161	10,161	10,161	10,161	10,161
22	Firm Purchases	319	319	319	319	319	319	319	319	319	319
23	New Resources										
24	Renewable	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	387	0	1,685	366	576	566	524	320	313	362
26	Combined Cycle CT	248	0	331	331	0	0	0	331	331	271
27	Coal	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	0	0	0	0	0	0
30	**Total Resources**	**11,115**	**10,480**	**12,497**	**11,177**	**11,056**	**11,046**	**11,004**	**11,131**	**11,124**	**11,113**
31	Reserves	1,462	1,721	1,647	1,472	1,438	1,434	1,419	1,492	1,463	1,464
32	Reserve Margin (RM) (%)	15.1	19.7	15.2	15.2	15.0	14.9	14.8	15.5	15.1	15.2

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 4 of 8

	Case Name	Base Case Study	Load Growth Rate Medium Low	Load Growth Rate Medium High	Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices High	High Gas Price Non-firm Prices Med	Lumped Resource Additions	Non-Firm Prices Lower by 25%	Non-Firm Prices Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Annual Energy in Year 2005 (MWa)										
1	Native Load	6,463	5,596	7,438	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	978	1,092	860	926	927	886	939	645	991
5	less DSM	(244)	(85)	(346)	(196)	(268)	(272)	(290)	(256)	(238)	(247)
6	**Total Requirements**	8,710	8,060	9,755	8,698	8,690	8,688	8,629	8,717	8,440	8,777
7	Existing Generation	7,768	7,652	7,680	7,672	7,748	7,751	7,715	7,783	7,514	7,830
8	Firm Purchases	400	400	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	8	0	20	10	12	27	5	125	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	0	1,513	340	533	525	488	298	289	337
13	Combined Cycle CT	183	0	163	266	0	0	0	232	113	210
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	0	0	0
17	**Total Resources**	8,710	8,060	9,755	8,698	8,690	8,688	8,629	8,717	8,440	8,777
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	55,189	52,938	57,983	54,729	55,408	55,496	55,508	55,109	54,185	55,205
19	NO_x	125	124	125	123	126	127	127	125	121	125
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	42,560	38,921	47,134	42,649	41,924	42,457	43,052	42,312	43,459	41,564
22	Real Levelized (mills/kWh)	42.55	43.92	41.31	42.21	42.11	42.69	43.44	42.38	43.39	41.57
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	42,990	39,062	47,849	42,973	42,445	42,995	43,705	42,773	43,885	41,998
25	Real Levelized (mills/kWh)	41.07	43.03	39.64	41.05	40.54	41.07	41.75	40.86	41.92	40.12
25	**IPM Obj Function (millions $)**	19,164	14,895	24,484	19,113	18,860	19,098	19,791	19,175	19,990	18,337

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 5 of 8

#	Case Name	Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
			25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	CCCT+2 25% Lower	CCCT+6 Medium	CCCT+10 25% Higher
	Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Summer Peak Capacity in Year 2005 (MW)										
1	Native Load	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM	(352)	(345)	(351)	(351)	(340)	(348)	(348)	(353)	(363)	(363)
4	**Total Requirements**	**9,940**	**9,947**	**9,941**	**9,941**	**9,952**	**9,944**	**9,945**	**9,939**	**9,929**	**9,929**
5	Existing Generation	10,123	10,123	10,123	10,122	10,123	10,122	10,122	10,123	10,123	10,123
6	Firm Purchases	424	424	424	424	424	424	424	424	424	424
7	New Resources										
8	Renewable	0	0	0	0	0	0	0	0	0	0
9	Cogeneration	363	297	364	371	470	470	470	86	150	344
10	Combined Cycle CT	222	297	223	226	130	121	169	168	102	168
11	Coal	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	0	0	0	331	321	321
14	**Total Resources**	**11,132**	**11,141**	**11,134**	**11,143**	**11,146**	**11,137**	**11,185**	**11,131**	**11,121**	**11,380**
15	Reserves	1,192	1,194	1,193	1,202	1,194	1,193	1,241	1,193	1,192	1,451
16	Reserve Margin (RM) (%)	12.0	12.0	12.0	12.1	12.0	12.0	12.5	12.0	12.0	14.6
	Winter Peak Capacity in Year 2005 (MW)										
17	Native Load	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	995	995	995	995	995	995	995	995	995
19	less DSM	(446)	(435)	(444)	(447)	(430)	(441)	(442)	(444)	(458)	(460)
20	**Total Requirements**	**9,653**	**9,664**	**9,655**	**9,652**	**9,670**	**9,658**	**9,657**	**9,655**	**9,641**	**9,640**
21	Existing Generation	10,162	10,161	10,162	10,161	10,162	10,161	10,161	10,161	10,161	10,161
22	Firm Purchases	319	319	319	319	319	319	319	319	319	319
23	New Resources										
24	Renewable	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	387	316	387	395	500	500	500	91	160	366
26	Combined Cycle CT	248	331	249	251	145	134	188	187	114	187
27	Coal	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	0	0	0	352	342	342
30	**Total Resources**	**11,115**	**11,127**	**11,116**	**11,127**	**11,125**	**11,115**	**11,169**	**11,110**	**11,096**	**11,375**
31	Reserves	1,462	1,463	1,461	1,474	1,456	1,457	1,512	1,455	1,455	1,735
32	Reserve Margin (RM) (%)	15.1	15.1	15.1	15.3	15.1	15.1	15.7	15.1	15.1	18.0

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 6 of 8

	Case Name	Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
									CCCT+2	CCCT+6	CCCT+10
			25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher
	Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Annual Energy in Year 2005 (MWa)										
1	Native Load	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	638	923	994	674	919	1,011	502	695	1,009
5	less DSM	(244)	(236)	(243)	(244)	(232)	(240)	(240)	(244)	(255)	(255)
6	**Total Requirements**	8,710	8,435	8,713	8,784	8,475	8,712	8,804	8,291	8,473	8,787
7	Existing Generation	7,768	7,514	7,768	7,822	7,519	7,742	7,791	7,520	7,778	7,822
8	Firm Purchases	400	400	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	148	2	0	107	6	0	204	49	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	261	360	368	400	465	465	85	149	341
13	Combined Cycle CT	183	113	184	194	49	100	148	68	86	149
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	13	13	75
17	**Total Resources**	8,710	8,435	8,713	8,784	8,475	8,712	8,804	8,291	8,473	8,787
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	55,189	54,153	55,186	55,226	54,090	55,134	55,157	54,344	55,334	55,310
19	NO_x	125	121	125	125	121	125	125	122	126	126
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	42,560	43,512	42,598	41,676	43,641	42,767	41,779	43,707	42,966	41,719
22	Real Levelized (mills/kWh)	42.55	43.43	42.58	41.64	43.53	42.73	41.74	43.68	43.03	41.79
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	42,990	43,932	43,025	42,098	44,051	43,187	42,196	44,146	43,415	42,167
25	Real Levelized (mills/kWh)	41.07	41.97	41.10	40.21	42.08	41.25	40.31	42.17	41.47	40.28
25	**IPM Obj Function (millions $)**	19,164	20,043	19,189	18,344	20,107	19,227	18,368	20,027	19,321	18,542

Note: (A) An additional 2, 6, or 10 mill/kWh was added to the CCCT cost to represent an additonal profit margin for an energy producer selling power in a sellers market.

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 7 of 8

	Case Name	Base Case Study	Added Transm: Test Transm Conversion	Added Transm: Bridger to OWC	Added Transm: Utah to OWC	Cheaper Renew-ables	Extend Inputs to 2045: Firm Contracts	Extend Inputs to 2045: Loads and DSM	Extend Inputs to 2045: All Inputs	Environmental Adders with CO2 Costs at: $10/ton	Environmental Adders with CO2 Costs at: $25/ton	Environmental Adders with CO2 Costs at: $40/ton
	Case #	**1**	**57**	**58**	**59**	**61**	**65**	**66**	**67**	**71**	**72**	**73**
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485	1,485	1,485	1,485	1,485	2,130	1,485	2,130	1,485	1,485	1,485
3	less DSM	(352)	(402)	(353)	(352)	(348)	(370)	(332)	(373)	(362)	(426)	(460)
4	**Total Requirements**	**9,940**	**9,890**	**9,940**	**9,940**	**9,944**	**10,567**	**9,960**	**10,564**	**9,930**	**9,866**	**9,832**
5	Existing Generation	10,123	10,123	10,122	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123
6	Firm Purchases	424	424	424	424	424	692	424	692	424	424	424
7	New Resources											
8	Renewable	0	0	0	0	54	0	0	0	0	592	876
9	Cogeneration	363	233	364	363	217	723	355	720	985	1,973	1,660
10	Combined Cycle CT	222	297	222	222	120	297	254	297	297	1,889	2,532
11	Coal	0	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	200	0	0	0	0	0	0
14	**Total Resources**	**11,132**	**11,077**	**11,132**	**11,132**	**11,137**	**11,835**	**11,155**	**11,832**	**11,829**	**15,002**	**15,616**
15	Reserves	1,192	1,187	1,192	1,192	1,157	1,268	1,195	1,268	1,899	4,740	5,199
16	Reserve Margin (RM) (%)	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	19.1	52.0	58.8
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	995	995	995	995	1,463	995	1,463	995	995	995
19	less DSM	(446)	(487)	(445)	(446)	(439)	(459)	(427)	(462)	(462)	(509)	(537)
20	**Total Requirements**	**9,653**	**9,612**	**9,654**	**9,653**	**9,660**	**10,108**	**9,672**	**10,105**	**9,637**	**9,590**	**9,562**
21	Existing Generation	10,162	10,161	10,161	10,162	10,162	10,161	10,162	10,161	10,161	10,161	10,161
22	Firm Purchases	319	319	319	319	319	954	319	954	319	319	319
23	New Resources											
24	Renewable	0	0	0	0	54	0	0	0	0	712	1,166
25	Cogeneration	387	248	387	387	230	769	377	766	1,048	2,099	1,766
26	Combined Cycle CT	248	331	247	248	133	331	283	331	331	2,025	2,709
27	Coal	0	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	200	0	0	0	0	0	0
30	**Total Resources**	**11,115**	**11,059**	**11,114**	**11,115**	**11,098**	**12,216**	**11,141**	**12,212**	**11,859**	**15,316**	**16,121**
31	Reserves	1,462	1,447	1,461	1,462	1,438	2,107	1,469	2,107	2,222	5,726	6,559
32	Reserve Margin (RM) (%)	15.1	15.1	15.1	15.1	14.9	20.8	15.2	20.8	23.1	59.7	68.6

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 8 of 8

		Base Case Study	Added Transm			Cheaper Renew-ables	Extend Inputs to 2045			Environmental Adders with CO2 Costs at		
	Case Name		Test Transm Conversion	Bridger to OWC	Utah to OWC		Firm Contracts	Loads and DSM	All Inputs	$10/ton	$25/ton	$40/ton
	Case #	1	57	58	59	61	65	66	67	71	72	73
	Annual Energy in Year 2005 (MWa)											
1	Native Load	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	300	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,683	1,266	1,683	1,266	1,266	1,266
4	Non-Firm Sales	921	890	954	926	912	971	931	970	239	180	283
5	less DSM	(244)	(272)	(244)	(244)	(240)	(256)	(227)	(255)	(256)	(287)	(304)
6	**Total Requirements**	8,710	8,650	8,743	8,715	8,706	9,165	8,736	9,166	8,017	7,921	8,013
7	Existing Generation	7,768	7,785	7,787	7,768	7,739	7,724	7,776	7,726	5,892	2,453	1,998
8	Firm Purchases	400	400	400	400	400	523	400	523	400	403	403
9	Non-Firm Purchases	0	3	0	4	5	0	4	0	449	627	498
10	New Resources											
11	Renewable	0	0	0	0	51	0	0	0	0	608	956
12	Cogeneration	360	231	360	360	214	716	351	713	975	1,953	1,644
13	Combined Cycle CT	183	232	196	183	99	202	205	203	302	1,878	2,514
14	Coal	0	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	198	0	0	0	0	0	0
17	**Total Resources**	8,710	8,650	8,743	8,715	8,706	9,165	8,736	9,166	8,017	7,921	8,013
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO2	55,189	55,160	55,320	55,211	54,216	54,851	55,220	54,838	44,911	24,956	20,639
19	NOx	125	125	126	125	125	125	125	125	91	32	22
	Financial Results with End Effects to 2045											
20	50-year Utility Cost											
21	NPV at 8.6% (million $)	42,560	41,877	43,039	43,060	42,277	42,273	45,026	45,141	43,665	52,388	55,552
22	Real Levelized (mills/kWh)	42.55	42.12	43.03	43.05	42.19	42.35	41.29	41.53	43.74	52.84	56.16
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	42,990	42,426	43,469	43,490	42,698	42,744	45,473	45,656	44,110	53,027	56,276
25	Real Levelized (mills/kWh)	41.07	40.53	41.52	41.54	40.79	40.83	39.97	40.13	42.13	50.65	53.76
25	**IPM Obj Function (millions $)**	19,164	19,541	19,154	19,163	18,657	22,121	22,579	26,347	34,736	46,812	56,486

The second page of Table 4-2 shows the annual energy output in 2005 for each set of cases. It also shows the average annual emissions and the financial results for each set. The emissions part of the table includes only CO2 and NOx because these are the two types of emissions that have the greatest impact.

The last part of Table 4-2 shows four measures of financial results:

- 50-year NPV (net present value) of utility cost;
- Real levelized mills/kWh for utility cost, derived from the NPV of utility cost;
- 50-year NPV of total resource cost (TRC); and
- Real levelized mills/kWh for TRC, derived from the NPV of TRC.

The financial results cover 50 years: 20 years in the study period and 30 years of end effects to 2045. All four financial measures are indicators of the impact on costs of changes in input assumptions. The company or the reader can compare any of these measures between the base case and any of the other cases using Table 4-2 or 4-3. Table 4-3 summarizes just the financial information for all of the cases. For both utility cost and TRC it includes the 50-year NPV, real levelized mills/kWh, and the percentage change from the base case for all four indicators.

The accuracy of a 50-year NPV for either utility cost or TRC depends on the accuracy of each of the modeling input assumptions. Those input assumptions predict key cost elements, such as gas prices and non-firm market prices. PacifiCorp does not have a crystal ball. Therefore, the company believes that any decision-making which relies on a 50-year NPV should be done very cautiously, and only on large differences in NPV amounts. Small differences in NPV (such as one percent or less) from one case to another are not meaningful. For reference in moving from one measure to another, a one mill change in the real levelized mills/kWh for TRC corresponds to about $1 billion in NPV of TRC.

No! Note! when you use UC mills/kWh in narrative

50-Year Utility and Total Resource Cost
Change from the Base Case

Table 4-3

Case Number	Study Title	Utility Cost: 50-Year NPV	Utility Cost: Real Levelized Mills/kWh	Utility Cost: Δ from Base Case (1) NPV	Utility Cost: Δ from Base Case (1) Mills/kWh	Total Resource Cost: 50-Year NPV	Total Resource Cost: Real Levelized Mills/kWh	Total Resource Cost: Δ from Base Case (1) NPV	Total Resource Cost: Δ from Base Case (1) Mills/kWh
1	Base Case	42,560	42.55	0.0%	0.0%	42,990	41.07	0.0%	0.0%
4	No Summer Season	42,284	41.98	-0.6%	-1.3%	42,610	40.70	-0.9%	-0.9%
5	No Turbine Upgrades	42,610	42.64	0.1%	0.2%	43,052	41.12	0.1%	0.1%
6	Without Hermiston	43,273	43.31	1.7%	1.8%	43,716	41.76	1.7%	1.7%
7	Med Load High Gas Without Hermiston	43,620	43.86	2.5%	3.1%	44,158	42.18	2.7%	2.7%
11	No DSM	43,471	41.52	2.1%	-2.4%	43,471	41.52	1.1%	1.1%
12	20% Conservation Advantage	42,564	43.00	0.0%	1.1%	43,259	41.32	0.6%	0.6%
13	15% Conservation Advantage	42,571	42.96	0.0%	1.0%	43,225	41.29	0.5%	0.5%
14	15% Conservation Disadvantage	42,578	42.17	0.0%	-0.9%	42,905	40.98	-0.2%	-0.2%
21	Med Low Load - Med Gas	38,921	43.92	-8.6%	3.2%	39,062	43.03	-9.1%	4.8%
22	Med High Load - Med Gas	47,134	41.31	10.7%	-2.9%	47,849	39.64	11.3%	-3.5%
31	Med Load - Low Gas	42,649	42.21	0.2%	-0.8%	42,973	41.05	0.0%	0.0%
32	Limited Gas (500 MW) at Med Esc	41,924	42.11	-1.5%	-1.0%	42,445	40.54	-1.3%	-1.3%
33	Med Load - High Gas = High Non-Firm	42,457	42.69	-0.2%	0.3%	42,995	41.07	0.0%	0.0%
34	High Gas - with Medium Non-firm Market Prices	43,052	43.44	1.2%	2.1%	43,705	41.75	1.7%	1.7% *
41	Resource Lumpiness	42,312	42.38	-0.6%	-0.4%	42,773	40.86	-0.5%	-0.5%
42	25% Lower Non-Firm Market Prices	43,459	43.39	2.1%	2.0%	43,885	41.92	2.1%	2.1% *
43	25% Higher Non-Firm Market Prices	41,564	41.57	-2.3%	-2.3%	41,998	40.12	-2.3%	-2.3%
44	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	43,512	43.43	2.2%	2.1%	43,932	41.97	2.2%	2.2% *
45	250 MW Plant in 1999 - Medium Non-Firm Market Prices	42,598	42.58	0.1%	0.1%	43,025	41.10	0.1%	0.1%
46	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	41,676	41.64	-2.1%	-2.1%	42,098	40.21	-2.1%	-2.1%
47	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	43,641	43.53	2.5%	2.3%	44,051	42.08	2.5%	2.5% *
48	500 MW Plant in 1999 - Medium Non-Firm Market Prices	42,767	42.73	0.5%	0.4%	43,187	41.25	0.5%	0.4%
49	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	41,779	41.74	-1.8%	-1.9%	42,196	40.31	-1.8%	-1.9%
50	Underbuild - 25% Lower Non-Firm Market Prices	43,707	43.68	2.7%	2.7%	44,146	42.17	2.7%	2.7% *
51	Underbuild - Medium Non-Firm Market Prices	42,966	43.03	1.0%	1.1%	43,415	41.47	1.0%	1.0%
52	Underbuild - 25% Higher Non-Firm Market Prices	41,719	41.79	-2.0%	-1.8%	42,167	40.28	-1.9%	-1.9%
57	Test of Transmission Plant Conversion	41,877	42.12	-1.6%	-1.0%	42,426	40.53	-1.3%	-1.3%
58	Added Transmission - Bridger to OWC	43,039	43.03	1.1%	1.1%	43,469	41.52	1.1%	1.1%
59	Added Transmission - Utah to OWC	43,060	43.05	1.2%	1.2%	43,490	41.54	1.2%	1.1%
61	Renewables at 35% of Capital Cost	42,277	42.19	-0.7%	-0.8%	42,698	40.79	-0.7%	-0.7%
65	Extension of all Existing Firm Wholesale Contracts	42,273	42.35	-0.7%	-0.5%	42,744	40.83	-0.6%	-0.6%
66	Extension of Loads & DSM to 2045	45,093	40.69	6.0%	-4.4%	45,540	39.41	5.9%	-4.0%
67	Extension of All Modeling to 2045	45,208	40.92	6.2%	-3.8%	45,723	39.57	6.4%	-3.7%
71	Low Environmental Adders	43,665	43.74	2.6%	2.8%	44,110	42.13	2.6%	2.6% *
72	Medium Environmental Adders	52,388	52.84	23.1%	24.2%	53,027	50.65	23.3%	23.3%
73	High Environmental Adders	55,552	56.16	30.5%	32.0%	56,276	53.76	30.9%	30.9%

(1) Δ from ~~Average~~ = [(Value / ~~Average~~) -1]
or base case
yes

In ratepayers interest to have higher non-firm prices

Mills/kWh for Total Utility Cost

Table 4-4

Case Number	Study Title	50-Yr Real Levelized Mills/kWh	Nominal Mills/kWh in 1996	1997	1998
1	Base Case	42.55	48.98	48.58	48.87
4	No Summer Season	41.98	48.95	48.49	48.72
5	No Turbine Upgrades	42.64	48.98	48.67	49.10
6	Without Hermiston	43.31	49.15	48.97	49.43
7	Med Load High Gas Without Hermiston	43.86	49.15	48.97	49.41
11	No DSM	41.52	48.89	48.30	48.42
12	20% Conservation Advantage	43.00	48.99	48.61	48.95
13	15% Conservation Advantage	42.96	48.99	48.62	48.91
14	15% Conservation Disadvantage	42.17	48.95	48.51	48.76
21	Med Low Load - Med Gas	43.92	50.32	50.20	50.68
22	Med High Load - Med Gas	41.31	48.15	47.19	47.83
31	Med Load - Low Gas	42.21	48.96	48.58	48.86
32	Limited Gas (500 MW) at Med Esc	42.11	48.99	48.58	48.86
33	Med Load - High Gas	42.69	48.99	48.58	48.86
34	High Gas - with Medium Non-firm Market Prices	43.44	48.99	48.61	48.91
41	Resource Lumpiness	42.38	48.99	48.61	48.91
42	25% Lower Non-Firm Market Prices	43.39	48.97	49.12	49.41
43	25% Higher Non-Firm Market Prices	41.57	48.98	47.93	48.20
44	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	43.43	48.97	49.10	49.39
45	250 MW Plant in 1999 - Medium Non-Firm Market Prices	42.58	48.97	48.57	48.86
46	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	41.64	48.98	47.93	48.19
47	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	43.53	48.96	49.09	49.37
48	500 MW Plant in 1999 - Medium Non-Firm Market Prices	42.73	48.97	48.57	48.85
49	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	41.74	48.97	47.92	48.18
50	Underbuild - 25% Lower Non-Firm Market Prices	43.68	48.98	49.14	49.43
51	Underbuild - Medium Non-Firm Market Prices	43.03	48.99	48.62	48.91
52	Underbuild - 25% Higher Non-Firm Market Prices	41.79	48.99	47.96	48.23
57	Test of Transmission Plant Conversion	42.12	48.99	48.62	48.92
58	Added Transmission - Bridger to OWC	43.03	48.96	48.50	49.09
59	Added Transmission - Utah to OWC	43.05	48.96	48.51	49.10
61	Renewables at 35% of Capital Cost	42.19	48.97	48.57	48.56
65	Extension of all Existing Firm Wholesale Contracts	42.35	48.98	48.81	49.71
66	Extension of Loads & DSM to 2045	40.69	48.96	48.54	48.81
67	Extension of All Modeling to 2045	40.92	48.98	48.79	49.67
71	Low Environmental Adders	43.74	49.91	50.07	50.79
72	Medium Environmental Adders	52.84	51.39	50.70	51.84
73	High Environmental Adders	56.16	53.29	52.98	55.15

Average Annual CO2, NOx and TSP Emissions

Change and Percent Change from the Base Case

Table 4-5

Case Number	Study Title	Average Annual Emissions (1,000 Tons)			Change from Base Case			% Change from Base Case		
		CO2	NOx	TSP	CO2	NOx	TSP	CO2	NOx	TSP
1	Base Case	55,189	125.2	11.18	-	-	-	-	-	-
4	No Summer Season	55,577	125.5	11.20	388	0.3	0.02	0.7%	0.2%	0.2%
5	No Turbine Upgrades	54,430	122.9	10.98	(758)	(2.3)	(0.20)	-1.4%	-1.9%	-1.8%
6	Without Hermiston	55,104	125.1	11.19	(85)	(0.1)	0.01	-0.2%	-0.1%	0.1%
7	Med Load High Gas Without Hermiston	55,413	126.4	11.26	224	1.2	0.08	0.4%	1.0%	0.7%
11	No DSM	55,921	125.2	11.21	732	(0.0)	0.03	1.3%	0.0%	0.3%
12	20% Conservation Advantage	55,094	125.4	11.18	(94)	0.2	(0.01)	-0.2%	0.2%	-0.1%
13	15% Conservation Advantage	55,118	125.4	11.18	(71)	0.2	(0.00)	-0.1%	0.2%	0.0%
14	15% Conservation Disadvantage	55,315	125.1	11.19	127	(0.1)	0.01	0.2%	-0.1%	0.1%
21	Med Low Load - Med Gas	52,938	124.3	11.00	(2,250)	(0.9)	(0.18)	-4.1%	-0.7%	-1.6%
22	Med High Load - Med Gas	57,983	125.5	11.32	2,794	0.3	0.14	5.1%	0.2%	1.2%
31	Med Load - Low Gas	54,729	123.4	11.01	(460)	(1.8)	(0.17)	-0.8%	-1.4%	-1.5%
32	Limited Gas (500 MW) at Med Esc	55,408	126.2	11.24	219	1.0	0.06	0.4%	0.8%	0.5%
33	Med Load - High Gas	55,496	126.5	11.26	308	1.3	0.08	0.6%	1.1%	0.7%
34	High Gas - with Medium Non-firm Market Prices	55,508	126.5	11.25	320	1.4	0.07	0.6%	1.1%	0.6%
41	Resource Lumpiness	55,109	125.0	11.18	(79)	(0.2)	(0.00)	-0.1%	-0.1%	0.0%
42	25% Lower Non-Firm Market Prices	54,185	121.4	10.81	(1,004)	(3.8)	(0.37)	-1.8%	-3.0%	-3.3%
43	25% Higher Non-Firm Market Prices	55,205	125.3	11.20	16	0.1	0.01	0.0%	0.1%	0.1%
44	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	54,153	121.3	10.81	(1,036)	(3.9)	(0.38)	-1.9%	-3.1%	-3.4%
45	250 MW Plant in 1999 - Medium Non-Firm Market Prices	55,186	125.2	11.18	(3)	(0.0)	(0.00)	0.0%	0.0%	0.0%
46	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	55,226	125.3	11.19	37	0.1	0.01	0.1%	0.1%	0.1%
47	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	54,090	121.0	10.79	(1,099)	(4.2)	(0.39)	-2.0%	-3.3%	-3.5%
48	500 MW Plant in 1999 - Medium Non-Firm Market Prices	55,134	125.0	11.15	(54)	(0.2)	(0.03)	-0.1%	-0.2%	-0.3%
49	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	55,157	125.1	11.17	(31)	(0.1)	(0.02)	-0.1%	-0.1%	-0.1%
50	Underbuild - 25% Lower Non-Firm Market Prices	54,344	121.7	10.82	(845)	(3.4)	(0.36)	-1.5%	-2.8%	-3.2%
51	Underbuild - Medium Non-Firm Market Prices	55,334	125.6	11.19	145	0.4	0.01	0.3%	0.3%	0.1%
52	Underbuild - 25% Higher Non-Firm Market Prices	55,310	125.6	11.21	122	0.4	0.03	0.2%	0.3%	0.3%
57	Test of Transmission Plant Conversion	55,160	125.3	11.24	(29)	0.2	0.06	-0.1%	0.1%	0.5%
58	Added Transmission - Bridger to OWC	55,320	125.6	11.23	132	0.4	0.05	0.2%	0.4%	0.4%
59	Added Transmission - Utah to OWC	55,211	125.3	11.19	23	0.1	0.01	0.0%	0.1%	0.1%
61	Renewables at 35% of Capital Cost	54,216	125.0	11.13	(972)	(0.2)	(0.05)	-1.8%	-0.1%	-0.5%
65	Extension of all Existing Firm Wholesale Contracts	54,851	125.4	11.18	(337)	0.2	(0.00)	-0.6%	0.2%	0.0%
66	Extension of Loads & DSM to 2045	55,220	125.2	11.19	32	(0.0)	0.00	0.1%	0.0%	0.0%
67	Extension of All Modeling to 2045	54,838	125.4	11.18	(351)	0.2	(0.00)	-0.6%	0.2%	0.0%
71	Low Environmental Adders	44,911	90.8	8.57	(10,277)	(34.4)	(2.61)	-18.6%	-27.5%	-23.4%
72	Medium Environmental Adders	24,956	32.3	2.95	(30,233)	(92.9)	(8.24)	-54.8%	-74.2%	-73.7%
73	High Environmental Adders	20,639	22.3	2.15	(34,550)	(102.9)	(9.03)	-62.6%	-82.2%	-80.8%

PacifiCorp chose to focus its evaluation of results on the financial measure that most closely matches its strategic concerns: customer prices. PacifiCorp believes that its success in keeping customer prices as low as possible will be key to its success in the increasingly competitive electricity markets. The real levelized mills/kWh of utility cost (the second financial indicator on Table 4-2) is the best long-term indicator of customer prices. It is a predictor of what overall average retail customer prices would be if all customer bills used only kWh usage (i.e., no customer or demand charges). The company chose to focus on mills/kWh of utility cost, because that indicator shows how alternative assumptions and actions would affect customer prices. The following discussion refers to this measure of the financial results as average customer prices, while recognizing that it ignores interstate allocation issues, interclass allocation issues, and customer load factor issues. Because of its concerns with the accuracy of any measure based on 50-year estimates of NPV (from which the customer price indicator is derived), the company also examined more short-term price indicators.

The discussion of each case includes the customer price impact in the next few years. Table 4-4 shows the levelized mills/kWh of utility cost (as an indicator of the average retail customer price) for each of the three years of the action plan period. For ease of presentation, the following discussion refers to these as 1996 customer prices, 1997 customer prices, and 1998 customer prices, again recognizing that they ignore interstate allocation issues, interclass allocation issues, and customer load factor issues.

The company recognizes that IRP rules and guidelines from the state regulatory commissions require the use of TRC for planning. The company's focus on customer prices is not ignoring TRC; in most cases the results for the two measures are consistent. The cases which resulted in inconsistent patterns for utility cost and TRC are the cases which altered the inputs for DSM. The discussion of the DSM cases, below, addresses this issue further.

Table 4-5 lists all of the cases and shows information for emissions. It includes the average annual emissions for CO_2, NO_x and TSP, the absolute level of change from the base case, and the percentage change from the base case.

Results of the RAMPP-4 Cases

The following discussion describes each case analyzed in RAMPP-4. Table 4-1 shows how each cases uses different input assumptions. Comparing the results of each sensitivity case to the base case provides an indication of the impact of changes in input assumptions in the sensitivity case. Numbering for the cases is not a continuous sequence.

Base Cases and Comparisons to RAMPP-3

1) **Base Case**
The base case assumed medium load growth at 2.07 percent per year in winter MW and medium gas prices at 2.11 percent real escalation per year. Most of the other cases use the base case assumptions, with one or two changes. The base case in RAMPP-3 also assumed medium load growth and medium gas price escalation, though the growth rates were not the same. The RAMPP-3 levels were 2.13 percent for load growth and 3.78 percent for gas price escalation with a lower beginning gas price in RAMPP-4.

In the base case the model added DSM beginning in 1996, Gadsby repowering beginning in 2002, and OWC cogeneration beginning in 2003. By 2005 the model added a total of 446 MW of DSM and 635 MW of gas-fired resources, for a total of 1,081 MW. The model also needed 109 MW of summer peak purchases for the year 2002. The results of the base case indicate resource actions in only three areas: DSM, summer peak purchases, and gas-fired baseload resources. Results of the other cases reinforce that DSM, summer peak purchases, and gas-fired baseload resources should be key elements of the action plan.

The financial model results for the base case indicate average customer prices of 42.55 mills/kWh. This figure is significant only for comparisons from one case to another. It shows 1996 customer prices of 48.98 mills/kWh, 1997 customer prices of 48.58 mills/kWh, and 1998 customer prices of 48.87 mills/kWh.

2) **With RAMPP-3 Data, With RAMPP-3 Code, With Hermiston**
This is case #213 from RAMPP-3. It is the case from RAMPP-3 that most closely matches RAMPP-4 assumptions; it included the Hermiston plant in the portfolio for the model to select it

(which it did). Subsequent model selections in that case thus assumed the presence of Hermiston in the existing system.

Since this is a RAMPP-3 case, it included more DSM than the RAMPP-4 cases. Each RAMPP-3 case included a pre-determined amount of DSM. In the RAMPP-4 cases the model selected much lower amounts of DSM than RAMPP-3's medium level of DSM.

In the RAMPP-4 case #2 (#213 from RAMPP-3) the model added 721 MW of coal, 247 MW of peaking resources, and 608 MW of DSM for a total of 1,576 MW of new resource additions. The RAMPP-4 base case (RAMPP-4 case #1) included 635 MW of cogeneration and 446 MW of DSM. Together they totaled 1,081 MW of new resource additions or 497 MW less than the RAMPP-3 case #213. The model's switch from selecting coal in RAMPP-3 to selecting gas-fired resources in RAMPP-4 reflects reductions in the cost of gas-fired resources. The decrease in total resource additions from RAMPP-3 to RAMPP-4 reflects the lower load forecast in RAMPP-4, the larger existing system in RAMPP-4, and the lower reserve margin in RAMPP-4. Allowing for these differences between the two RAMPP cycles, the company concluded that the results of RAMPP-4 cases #1 and #2 supported the consistency of RAMPP-4 results with RAMPP-3 results. Another section of this chapter, below, compares the RAMPP-3 and RAMPP-4 results.

3) **With RAMPP-3 Data, with RAMPP-4 Code, With Hermiston**
This case used RAMPP-4 IPM code, but RAMPP-3 data inputs. It tested the impact of updating the IPM code from RAMPP-3 to RAMPP-4. A comparison of the results of this case with the RAMPP-3 Case #213 shows the impact of just the code changes. Note: The RAMPP-3 data did not include summer peaks, so this case shows the impact of all RAMPP-4 code changes except the summer peak capability.

Comparing this case to RAMPP-4 case #2 shows that using the RAMPP-4 code produces results almost identical to the RAMPP-3 code. RAMPP-4 Case #2 included 608 MW of DSM; case #3 included 616 MW of DSM. Case #2 had 721 MW of coal; case #3 had 698 MW of coal. Case #2 had 247 MW of peaking resources; case #3 had 262 MW of peaking resources. The minor differences are due to modeling inconsistencies in the RAMPP-3 code. PacifiCorp and ICF Resources, the model vendor, found these inconsistencies after completion of the RAMPP-3 planning cycle. ICF Resources corrected the errors before

RAMPP-4 modeling began. These minor corrections, mainly in the treatment of non-firm sales during non-run years, changed the results slightly. Both of these cases selected coal-fired resources instead of gas-fired resources, because they used RAMPP-3 data that had lower coal prices and higher gas prices than did RAMPP-4 data.

4) **With No Summer Data**
   This case is the same as the base case, except it included no summer data on loads or resources. Since this case used RAMPP-4 data and RAMPP-4 code, comparing it to the RAMPP-4 base case (RAMPP-4 case #1) shows the impact of adding the summer peak capability to the model.

In RAMPP-3 the model did not recognize summer peaking needs. ICF Resources made the code change to include the summer season before modeling for RAMPP-4 began. Thus, in RAMPP-4 the model recognized both winter and summer peaking needs. In RAMPP-3, when the model did not recognize summer peaking needs, it selected new resources based only on the winter reserve margin requirement. PacifiCorp's system is more stressed in the summer than the winter because the company has more winter peaking resources available to it than summer peaking resources. The retail load is still winter peaking; winter peaks for the retail load exceed summer peaks through the planning horizon. However, because the company currently has more winter peaking resources available to it, the winter reserve margin is larger than the summer reserve margin. In this situation, not recognizing summer would reduce the apparent need for new resources.

This no-summer case added 302 MW less of gas-fired resources and 1 MWa less of DSM, compared to the base case (which included the summer data). Planning based only on winter needs could result in under-estimating resource requirements.

The financial model results for the case using no summer season data show average customer prices of 41.98 mills/kWh, compared to the base case of 42.55 mills/kWh. These lower prices resulted from fewer resources being added to the system in case #4.

Altered Base System Assumptions

5) **With No Turbine Upgrades**
All of the cases except this one included 150 MW of turbine upgrades that PacifiCorp plans to implement in the next few years. The previous chapter described these upgrades. These are cost-effective improvements to ten units at six of the company's coal plants. This case tested the cost effectiveness of the upgrades by comparing customer prices under this case with customer prices under the base case; another test is the net present value (NPV) of the total utility cost of this case to that of the base case (case #1). Turbine upgrades were not an option during RAMPP-3, so there is no comparable RAMPP-3 case.

Without the turbine upgrades, the model selected 7 MW more DSM (453 MW by 2005 instead of 446 MW in the base case) and 154 MW more of gas-fired resources (789 MW instead of 635 MW) by 2005. Since summer reserve margin requirements drove model selections, the model added exactly 150 MW more as measured in summer MW. This total additions in winter MW were higher because gas-fired resources have more output under lower air temperatures.

Most significant are the financial results. Average customer prices were 42.64 mills/kWh without the turbine upgrades and 42.55 mills/kWh with the upgrades (in the base case). The 1997 customer prices and 1998 customer prices are higher without the turbine upgrades than they are with the upgrades because the upgrades would improve the efficiency of the company's existing plants, thereby reducing generating costs.

6) **Without Hermiston with Medium Gas Escalation**
This case excluded Hermiston from both the existing system and the portfolio, using base case price escalation assumptions for gas. RAMPP-3 did not include the Hermiston plant in the existing system or portfolio except for one sensitivity; therefore this case is similar to some of the RAMPP-3 cases.

Both this case and the next tested the impact of excluding the Hermiston plant from current and future resources. This case assumed medium gas price escalation, while case #7 assumed high gas price escalation. Without Hermiston, the model added 9 MW more of DSM (455 MW instead of 446 MW in the base case), and 457 MW more of gas-fired resources (1,091 MW instead of 635 MW in the base case). All together, the model added 1,546 MW of new resource additions, 466 MW more than in the base case.

The financial results of case #6 underscore the benefits of acquiring Hermiston. Without Hermiston, average customer prices were 43.31 mills/kWh, compared to 42.55 mills/kWh in the base case. For 1996, 1997 and 1998, customer prices were higher without Hermiston than they were in the base case.

7) **Without Hermiston with High Gas Escalation**
This case excluded Hermiston from both the existing system and the portfolio, using the high price escalation assumptions for gas. This case is similar to some of the RAMPP-3 cases.

Under the assumption of no Hermiston and high gas price escalation, the model added 41 MW more of DSM (487 MW instead of 446 MW in the base case), and 394 MW more of gas-fired resources (1,028 MW instead of 635 MW in the base case). Higher gas price escalation made DSM more attractive and made gas-fired resources less attractive.

The financial results of case #7 also underscore the benefits of acquiring Hermiston. Without Hermiston and with high gas price escalation, average customer prices were 43.86 mills/kWh compared to 42.69 mills/kWh in the high gas case (#33 from RAMPP-4). For 1996, 1997 and 1998, customer prices were higher in RAMPP-4 case #7 (without Hermiston and with high gas price escalation) than they were in RAMPP-4 case #33 (with Hermiston and with high gas).

As a result of comments on the RAMPP-4 draft report, the company performed an additional run, without Hermiston and with low gas price escalation. Since this run occurred at the end of the process, after preparation of multiple tables for the report, the tables do not include the results of this case. However, the Appendix includes tables showing the full results for each of the cases. It includes five tables for each case: additions by year in MWa (energy), additions by year in winter MW, additions by year in summer MW, emissions by year, and financial results by year. The financial results indicate that even under low gas price escalation the presence of Hermiston in the existing system lowers customer prices. The real levelized utility cost was 43.09 mills/kWh in this extra case of no-Hermiston and low gas price escalation, compared to the base case's real levelized utility cost of 42.55.

DSM Sensitivities

From prior RAMPP cycles, the company has learned that the four measures of financial results (NPV of utility cost, real levelized mills/kWh of utility cost, NPV of TRC, and real levelized mills/kWh of TRC) follow similar patterns. The company looked at the percentage change from the base case for the four results for each of the cases. In almost all of the cases the percentage change for all four indicators is in the same direction and within one percent of each other. Whether focusing on one criterion or another one, the analyst would reach similar conclusions. The exception to this pattern is when the inputs for DSM vary, as occurred in the following four cases. Table 4-3, earlier in this chapter, shows the financial results for all of the cases.

The discussion of the following four cases therefore addresses both customer prices and TRC results. In developing utility cost and TRC, the financial model used the same prices for the DSM inputs as the base case. This is because the cases with altered DSM prices used artificially lowered prices. The cost of DSM measures was reduced for modeling, even though the cost of the measures would be unchanged in reality. It is appropriate for the model to "see" only the reduced costs; it is not appropriate for the financial model to "see" those reduced costs. It should use actual costs. Therefore, the financial indicators show only the impact on costs due to alternative resource choices because of changed DSM cost inputs.

11) **With No DSM**
This case included no DSM. All other inputs were the same as the base case. It provided a comparison of resource choices and timing for the other cases, all of which allowed the model to select the amount of DSM. RAMPP-3 did not include a case that excluded DSM.

Not allowing the model to select DSM caused the addition of 1,051 MW of gas-fired resources by 2005. This compares to total gas-fired resources of 635 MW and total resource additions of 1,081 MW when DSM was part of the portfolio. The model substituted gas-fired baseload resources when DSM was not in the portfolio. Preventing the model from selecting DSM also increased the amount of summer peak purchases. The base case included only 109 MW of summer peak purchases in 2002; this case included 104 MW in 2000, 157 MW in 2001, and 274 MW in 2002. Table 6-3 in the RAMPP-4 Action Plan chapter shows the annual amounts of summer peak purchase additions for each of the cases. The comparison of this case with the base case shows that the model was using DSM to reduce the amount of additional gas-fired resources and to reduce the requirements for summer peak purchases.

The financial model results for this case (with no DSM) show average customer prices of 41.52 mills/kWh, compared to the base case of 42.55 mills/kWh. Also, the 1996, 1997 and 1998 customer prices were slightly lower under the no DSM case than they were in the base case. The lower prices were due to the greater number of kWhs being sold relative to total system costs.

Removing all DSM in case #11 raised the NPV for both utility cost and TRC, increasing TRC by 1.1 percent. However, it lowered customer prices and mills/kWh for TRC, lowering prices by 2.4 percent. Focusing on price impacts would lead to a conclusion that removing all DSM was more beneficial than basing a conclusion on TRC results. However, the company did not choose this path in its action plan.

12) **With 20 Percent Cost Advantage for Conservation**

This case reduced the cost of all DSM initiatives by 20 percent. It reflected three impacts. First, the 1978 Regional Act specified that conservation is to receive a 10 percent cost advantage relative to supply-side resource choices. Second, conservation can provide a benefit by delaying transmission and distribution (T&D) investments. This accounts for five percent of the cost advantage. To determine if a slightly lower cost of measures would affect resource choices, this case lowered the cost of the DSM inputs another five percent. RAMPP-3 did not include a comparable case.

Artificially lowering the cost of all DSM measures by 20 percent increased the model's use of DSM from 446 MW in the base case to 529 MW. It reduced the need for summer peak purchases to only 47 MW in 2002, about half the amount in the base case. It also reduced the amount of gas-fired resources selected from 635 MW in the base case to 512 MW. However, the amount of total resources added was similar to the base case: 1,081 MW in the base case and 1,041 MW in case #12.

Giving DSM a 20 percent cost advantage had a very small impact on TRC and no impact on utility cost; it raised both customer prices and mills/kWh for TRC. It increased NPV of TRC by 0.6 percent and increased prices by 1.1 percent. These results are too close to attribute any significance to their difference. The company did not choose this path in its action plan.

13) **With 15 Percent Cost Advantage for Conservation**
This case reduced the cost of all DSM initiatives by 15 percent. It included the first two impacts listed under case #12: the 10 percent cost advantage relative to supply-side resources from the 1978 Regional Act and a five percent reduction for delaying transmission and distribution investments. RAMPP-3 did not include a comparable case.

Artificially lowering the cost of all DSM measures by 15 percent increased the model's use of DSM by 69 MW -- from 446 MW in the base case to 515 MW. It reduced the need for summer peak purchases to only 62 MW in 2002. Lowering DSM costs also reduced the amount of gas-fired resources selected from 635 MW in the base case to 529 MW. However, the total resources added by 2005 was similar: 1,081 MW in the base case and 1,044 MW in case #13.

Giving DSM a 15 percent cost advantage had a very small impact on TRC and no impact on utility cost; it raised both customer prices and mills/kWh for TRC. It increased NPV of TRC by 0.5 percent and increased prices by one percent. These results are too close to attribute any significance to their difference. This is the case the company used to develop the DSM in its action plan. The amount of DSM in the action plan for the first three years is the same as the amount of DSM added by the model in each of the first three years.

14) **With 15 Percent Cost Disadvantage for Conservation**
PacifiCorp may be under-estimating the cost of DSM or over-estimated the performance of DSM. This case recognizes both uncertainties by increasing the cost of DSM by 15 percent. RAMPP-3 did not include a comparable case.

Artificially raising the cost of all DSM measures by 15 percent reduced the model's use of DSM by 59 MW -- from 446 MW in the base case to 387 MW. It increased the need for summer peak purchases to 130 MW in 2002 (from 109 MW in the base case). The higher DSM costs also increased the amount of gas-fired resources selected from 635 MW in the base case to 704 MW.

Case #14 with a 15 percent cost disadvantage for DSM decreased prices by 0.9 percent and decreased the NPV of TRC by 0.2 percent. These results are too close to attribute any significance to their difference. The company did not choose this case for its action plan.

The customer price and TRC analysis leads to a conclusion that the best DSM strategy from a customer price viewpoint is to do no DSM; the best DSM strategy from a TRC viewpoint is to give DSM a 15 percent cost disadvantage. The company followed neither of these strategies. Instead, it used the case which gave DSM a 15 percent cost advantage.

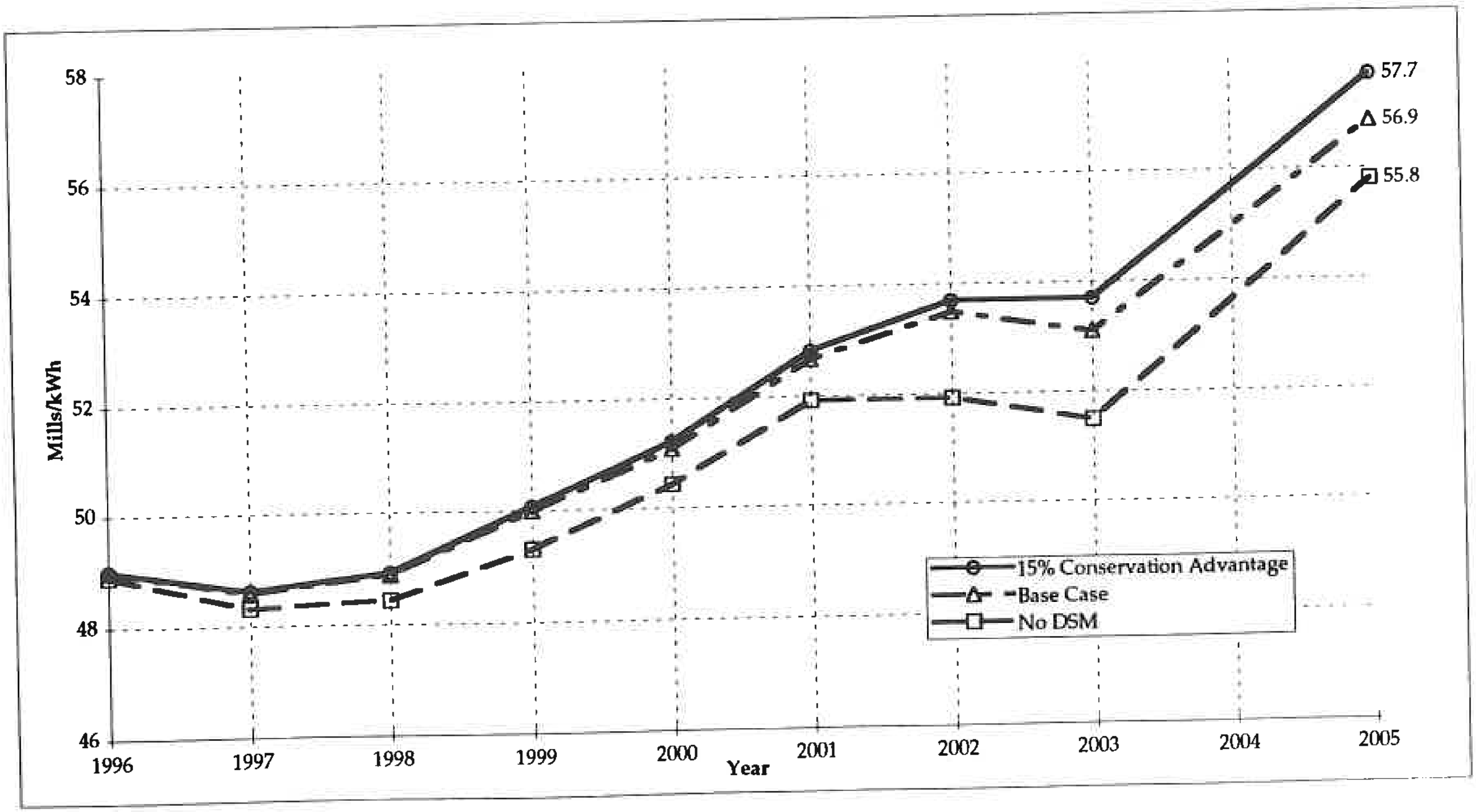
Graph 4-6 shows the impact on yearly customer prices of the base case compared to the no DSM case and the case with 15 percent reduced costs for DSM. The no DSM case would result in lower customer prices in the first three years, but the case with DSM costs reduced by 15 percent would have the same price impacts as the base case.

Load Growth Variation

Graph 4-7 shows, through 2005, the total amount of resources added by load growth level. Load growth under each of the three levels would result in the following amounts of additional MW to retail load by 2005: 787 MW under medium-low load growth, 1,689 MW under medium, and 2,630 MW under medium-high. These amounts come from Table 3-4 in Chapter 3. Under all three load growth levels, the only resources selected were DSM, gas-fired baseload plants, and summer peak purchases. The amount of each resource varied by load growth level. The company reaches resource balance in the year 2005 under medium-low load growth, in 2003 for medium, and in 2000 for medium-high. Under medium-low load growth, the model needed only a small amount of DSM. Under medium load growth, the model added more DSM, as well as cogeneration and combined-cycle combustion turbines (CCCTs). Under medium-high load growth, the model added more DSM and more cogeneration and CCCTs.

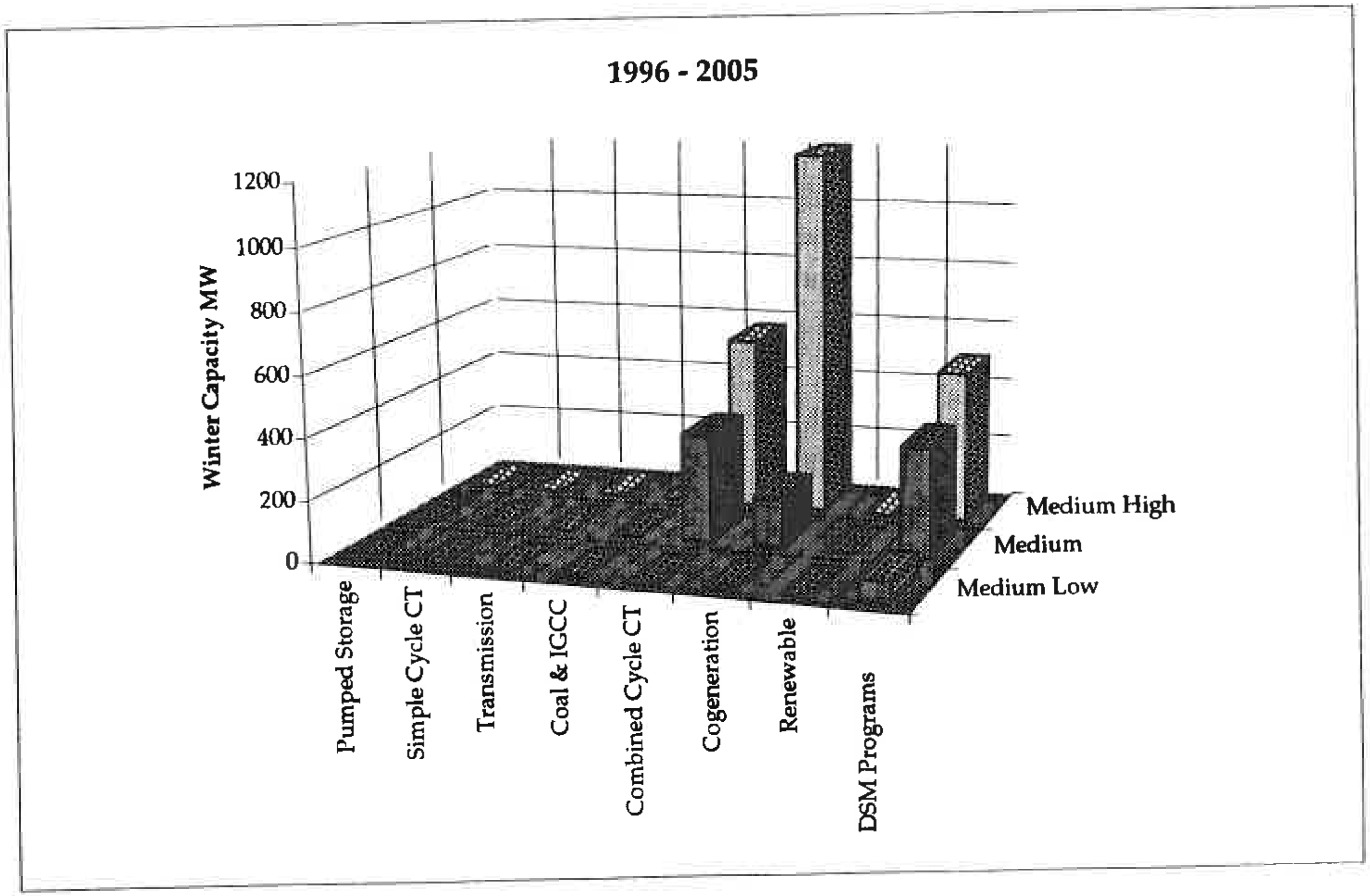
Yearly Nominal Mills/kWh of Utility Cost for DSM Cases

Graph 4-6



Resource Additions by Load Growth Level

Graph 4-7



21) **Medium-Low Load Growth**
This case used the medium-low load forecast, which is 1.06 percent growth per year in winter MW for the 20-year planning horizon. This reduced level from the medium forecast might occur from a lower level of economic activity in the region, some pricing designs, changes in customers' fuel choices, hook-up fees, or increased competition. If load growth were at the medium-low level, the system would need fewer new resources. This case shows the degree of delay that would be possible under lower load growth. RAMPP-3 included cases using medium-low load growth of 1.25 percent per year, but other significant assumptions were different in RAMPP-3.

Under medium-low load growth, load was 902 MW less in the 10th year than under medium load growth (the base case). If load growth falls to the medium-low level, PacifiCorp will not need to make any resource additions through 2005 other than 131 MW of DSM.

In RAMPP-3 the medium-low load growth case used 1.25 percent annual load growth, compared to 1.06 percent in RAMPP-4. RAMPP-3 showed 814 MW of total new resource additions in the first 10 years compared to only 131 MW (all DSM) for RAMPP-4. This represents a difference of 683 MW of total resources. Given that Hermiston and the turbine upgrades are included in RAMPP-4, and weren't in RAMPP-3, and the fact that load growth in RAMPP-4 is slightly lower, the results for the two planning cycles appear to be consistent.

The financial model results for the medium-low load growth case in RAMPP-4 show average customer prices of 43.92 mills/kWh, compared to the base case of 42.55 mills/kWh. For 1996, 1997 and 1998, customer prices were higher for medium-low load growth than in the base case. Lower load growth inhibits the most efficient use of the system, resulting in higher prices for customers.

22) **Medium-High Load Growth**
This case used the medium-high load forecast, which was 2.93 percent growth per year in winter MW for the 20-year planning horizon. Higher load growth could occur from a higher level of economic activity in the region or from PacifiCorp gaining new customers through competition. If load growth were at the medium-high level, the system would need more resources sooner. This case shows the degree of increased need under

higher load growth. RAMPP-3 included cases using medium-high load growth of 3.0 percent per year, but other significant assumptions were different.

Under medium-high load growth, load was 941 MW more in the tenth year than under medium load growth (the base case). Assuming medium-high load growth, the model added 619 MW of DSM by 2005, compared to 446 MW in the base case. It added significant amounts of summer peak purchases starting in 1996: 277 MW in 1996, 38 MW in 1997, 201 MW in 1998, 393 MW in 1999, and 500 MW in each of 2000, 2001, and 2002. The model also added 2,018 MW of gas-fired resources, or 1,383 MW more than for medium load growth. Thus total resource additions by 2005 were 2,635 MW, compared to 1,081 MW in the base case.

In RAMPP-3 the medium-high load growth case used 3.0 percent annual load growth, compared to 2.93 percent in RAMPP-4. The results for RAMPP-3 showed 3,316 MW of total new resource additions in the first 10 years. This represents a difference of 680 MW of total resources. Given that Hermiston and the turbine upgrades are included in RAMPP-4, and weren't in RAMPP-3, and the fact that medium-high load growth in RAMPP-3 and RAMPP-4 are almost the same, the results for the two IRP cycles appear to be consistent.

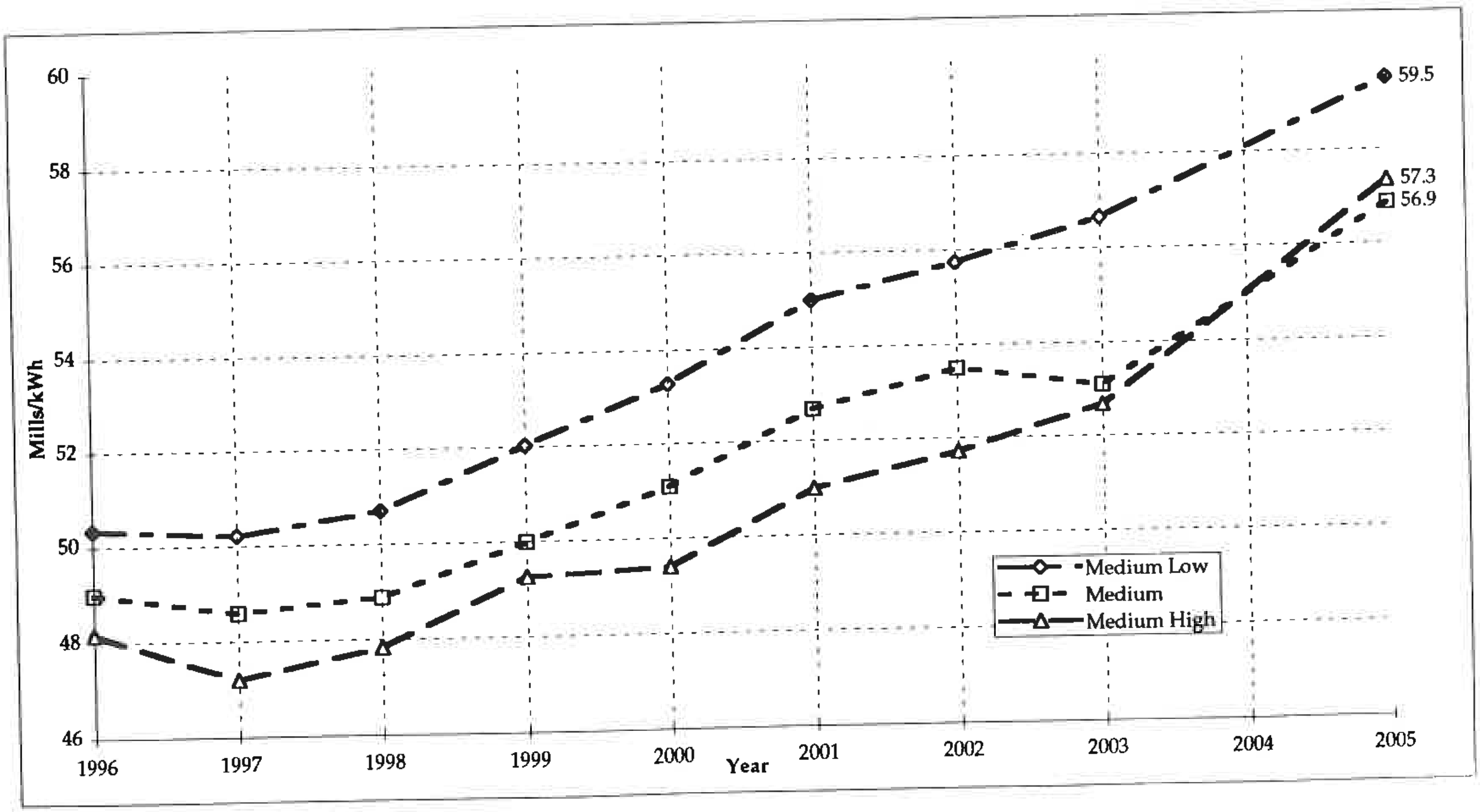
The financial model results for the medium-high load growth case show average customer prices of 41.31 mills/kWh, compared to the base case of 42.55 mills/kWh. For 1996, 1997 and 1998, customer prices were higher in the base case than in the case with higher load growth. Although higher load growth raised system costs, the larger number of kWhs sold kept the price per kWh lower than in the base case.

Graph 4-8 shows customer prices for the three load growth cases. Consistently, through 2003, medium-high load growth creates the lowest customer prices and medium-low load growth created the highest customer prices. A later section of this chapter discusses in more detail a comparison of the results of RAMPP-3 and RAMPP-4.

Load growth variation is a good proxy for the possible impacts on the company of competitive restructuring of the electric industry. Such a restructuring could lead to increased or decreased load growth. One of the lessons learned from RAMPP-3 was that low load growth (lower than the medium-low analyzed in RAMPP-4) would simply extend the

Yearly Nominal Mills/kWh of Utility Cost by Load Growth Level

Graph 4-8



surplus longer than occurred in the medium-low, and that high load growth (higher than the medium-high analyzed in RAMPP-4) would bring a need to add resources sooner, but they would be the same resources that the model added in the medium-high case. Lower load growth would lead to higher customer prices, and higher load growth would lead to lower customer prices.

Gas Price Variation

Graph 4-9 shows the amount of resources added by 2005 according gas price level. The model added the most gas-fired resources (932 MW) assuming low gas price escalation. Under medium gas price escalation it added 635 MW. Under high gas price escalation, the model added the least gas-fired resources (576 MW). Descriptions of each of the gas price variation cases indicates the non-firm market price assumption for that case. This is because the company believes that non-firm market price escalation is closely tied to gas price escalation. This is because gas prices are currently the least-cost supply-side resource, and thus gas-fired resources compete with non-firm market power.

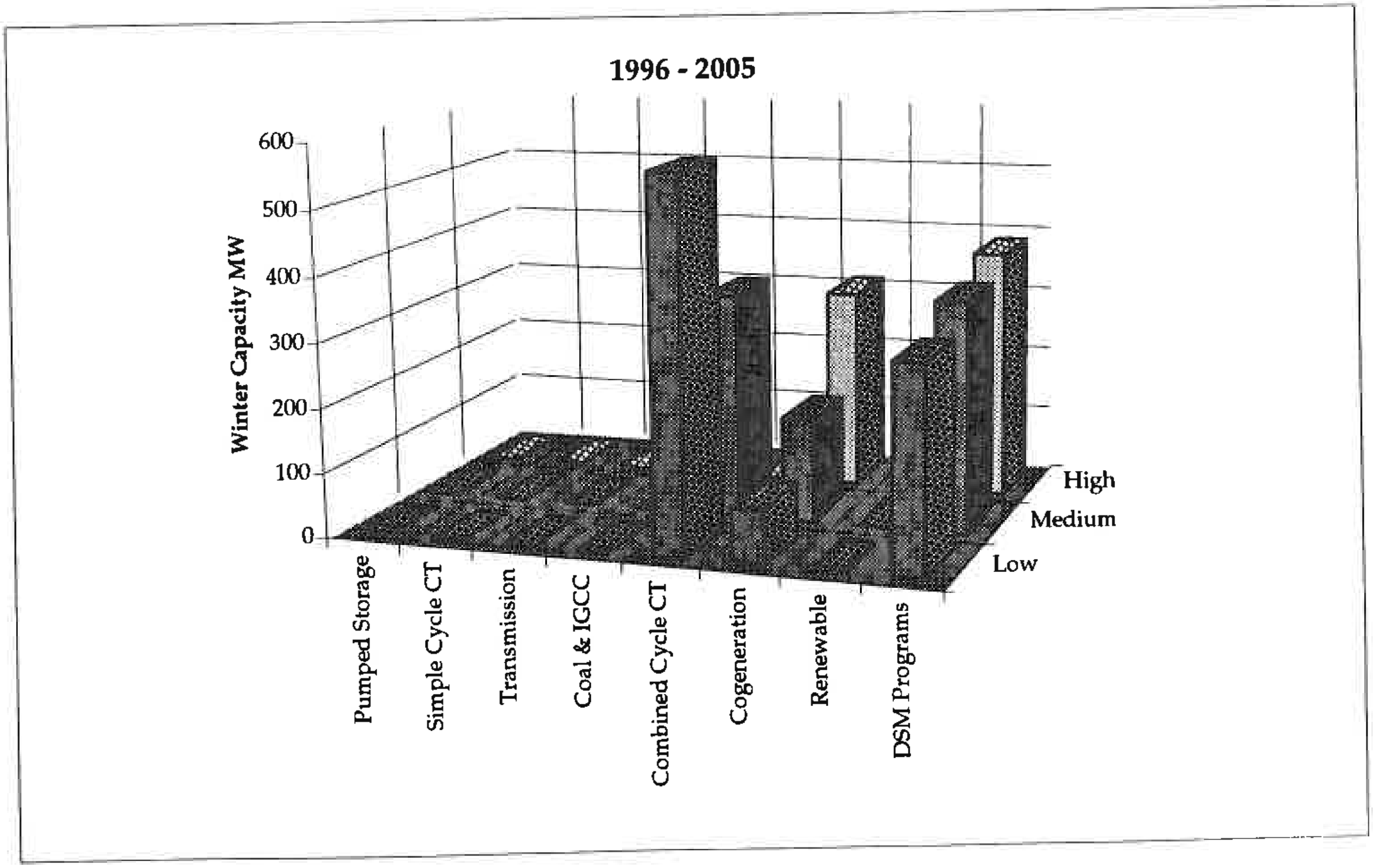
31)**Low Gas Price Escalation with Low Non-Firm Market Prices**
This case assumed a low gas price escalation of zero percent real increase per year. RAMPP-3 used 1.71 percent real annual escalation for its low case. This case also used non-firm market prices that escalate at zero percent real. Comparing this case to the base case shows the impact of lower gas price escalation on resource choices.

Under the low gas price assumption, the model selected slightly less DSM -- 394 MW instead of the 446 MW in the base case -- by 2005, only 30 MW of summer peak purchases in 2002, and slightly more gas-fired resources -- 697 MW instead of 635 MW in the base case. These results indicate that low gas price assumptions had little effect on model choices.

The financial model results for the case with low gas price escalation show average customer prices of 42.21 mills/kWh, compared to the base case of 42.55 mills/kWh. Lower gas price escalation had no impact on customer prices in 1996, 1997 and 1998. The benefits to customers of lower gas price escalation occur after the initial three-year period.

Resource Additions by Gas Price Level

Graph 4-9



The company's reduced revenue from lower non-firm market prices offsets the reduced costs of new gas-fired resources.

32) **With Limited Gas at Medium Price Escalation (500 MW) and High Non-Firm Market Prices**
This case allows the model to add only 500 MW of gas-fired resources using medium gas escalation assumptions (at 2.11 percent real escalation per year). Additional gas-fired resources must use high gas escalation assumptions at 3.78 percent real escalation per year. The comparable levels in RAMPP-3 were 3.78 percent real annual escalation for the medium case and 5.56 percent real annual escalation for the high case. This case used non-firm market prices that escalate at 80 percent of the high gas price escalation rate.

Under this assumption, the model selected 482 MW of DSM by 2005 compared to 446 MW in the base case (which assumed a medium price escalation for all gas-fired resources) and 576 MW of gas-fired resources compared to 635 MW in the base case.

The financial model results for this case show average customer prices of 42.11 mills/kWh, compared to the base case of 42.55 mills/kWh. This assumption of a limited amount of gas at medium gas price escalation had no impact on customer prices in 1996, 1997 and 1998.

33) **High Gas Price Escalation with High Non-Firm Market Prices**
This case assumed a high gas price escalation rate of 3.78 percent, which is equal to the RAMPP-3 medium gas escalation assumption. It used non-firm market prices that escalate at 80 percent of the high gas price escalation rate. Comparing this case to the base case shows the impact of higher gas price escalation on resource choices.

Assuming gas prices will escalate at the 3.78 percent real level, the model selected almost the same amount of DSM it did in the previous case -- 487 MW by 2005 versus 482 MW. The model added only 566 MW of gas-fired resources in the first 10 years instead of 635 MW in the base case.

The financial model results for this case show average customer prices of 42.69 mills/kWh, compared to the base case of 42.55 mills/kWh. For the years 1996, 1997 and 1998, customer prices were the same as those in the base case. Costs for this case were similar to the base case in spite of the increase in gas price escalation because the margin on non-firm sales was higher. This increase in total revenues offset the increased costs from higher gas price escalation.

34) **High Gas Price Escalation with Medium Non-Firm Market Prices**
This case breaks the link between gas price escalation and non-firm market prices. In all the other cases, low gas price escalation occurs with low non-firm market prices, medium gas price escalation occurs with medium non-firm market prices, and high gas price escalation occurs with high non-firm market prices. In case #34, gas prices escalated at the high level (3.78 percent real) while non-firm market prices escalated at the medium level (80 percent of 2.11 percent real).

With gas prices at the high escalation level but non-firm prices at the medium level, the model chose slightly more DSM (514 MW instead of the 487 MW when both gas price escalation and non-firm prices were high). Lower non-firm prices slightly reduced the amount of gas-fired resources (524 MW instead of 566 MW in the case with both high gas price escalation and high non-firm prices).

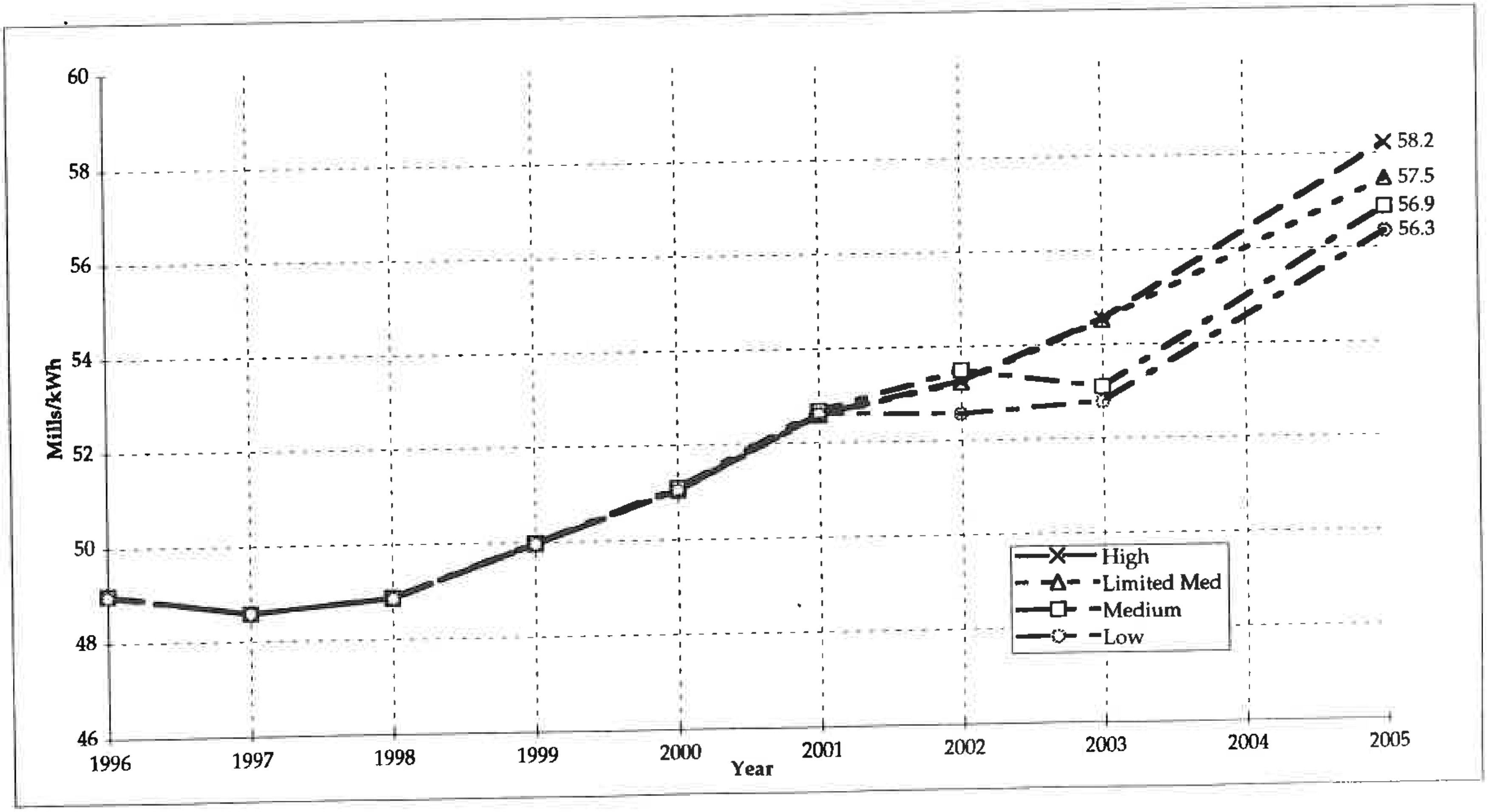
With both high gas price escalation and high non-firm prices, average customer prices would be 42.69; breaking the link and having medium non-firm prices would result in higher average customer prices at 43.44. Medium non-firm prices (instead of high non-firm prices) would result in lower revenues to the company to offset the higher costs from high gas price escalation. Causing price ↑

With gas price and non-firm market priced linked, the increase in utility cost from higher gas price escalation is offset by the increased revenue from non-firm sales. The non-firm sales revenues that the company credits to the retail revenue requirement tends to be higher when non-firm prices are higher. Should this link between gas price and non-firm market price fail, gas price increases could result in higher customer prices.

Graph 4-10 shows the impact of various gas price escalation rates on customer electricity prices. Through 2001, there is virtually no impact on customer prices because the model selected no gas-fired resources before that date under medium load growth. After 2001, higher gas price escalation starts causing higher customer prices.

Yearly Nominal Mills/kWh of Utility Cost by Gas Price Escalation Rate

Graph 4-10



An alternative approach would be to vary the gas price level after the company had built or acquired a substantial amount of gas-fired resources. Given the relationship of gas price escalation to non-firm market prices, the company does not believe that customer prices would be adversely affected. In addition, if gas price escalation were to quickly rise the company has the option of increasing output at its coal-fired units, building more coal-fired units, buying more power on the non-firm market, or pursuing other resource choices.

Wholesale Market

41) **With Resource Lumpiness**
This case forces the model to add new resources in realistic large sizes. In all of the other cases the model's code adds resources in the exact size increments needed each year to meet the reserve margin requirements. This case assumed medium gas price escalation. RAMPP-3 did not include a comparable case.

To run this case, PacifiCorp forced large chunks of new resources into the existing system in future years. Although the model did not select the amount or timing of supply-side resources, it did select the amount and timing of DSM. The model added slightly more DSM in this case than in the base case -- 460 MW compared to 446 MW. It added only 33 MW of summer peak purchases in 2002.

Case #41 could have very different results, depending on how the lumped acquisitions occurred. Therefore, the reader should not attribute too much significance to the financial results. Under the assumptions used in this case, the results are valid. However, acquiring resource chunks at different times or in different amounts would yield different results. The prices for case #41 were comparable to base case prices.

42) **With Lower Non-Firm Market Prices**
This case lowered non-firm market prices by 25 percent from the base case level. Comparing this case to the base case shows the impact of lower non-firm market prices on total system costs. RAMPP-3 included a case with non-firm market prices lowered by 20 percent, case #252.

From \$19 peak → To \$14.25
16 offpeak → \$12.00

Sales only not purchases same effect on price

PV + COP, today
13.5 and 10

For this case, the 1997 non-firm market price was 25 percent lower than the 1997 price in the base case. It then increased at 80 percent of the medium gas price escalation rate. Assuming lower non-firm market prices, the resource choices through 2005 would be almost the same as the base case. However, non-firm sales would be less than in the base case by about 200 MWa per year. Assuming lower non-firm prices, the range of non-firm sales from 1996 through 2005 never exceeded 706 MWa. It stayed at about 500 MWa. In the base case the range was about 700 MWa. For case #42, non-firm purchases increased compared to the base case. With lower non-firm prices, the model purchased around 300 MWa a year, compared to less than 100 MWa per year for the base case.

The financial model results for the case using lower non-firm market prices show average customer prices of 43.39 mills/kWh, compared to the base case of 42.55 mills/kWh. For 1997 and 1998, customer prices were higher than in the base case. This case resulted in higher prices for customers because lower non-firm market prices did not allow the company to obtain as much wholesale revenue, which can help offset costs for retail customers.

7.1% (~2%)

↑ price impact on non-firm hurts customers

43) **With Higher Non-Firm Market Prices**

This case raised non-firm market prices by 25 percent from the base case level. Comparing this case to the base case shows the impact of higher non-firm market prices on total system costs. RAMPP-3 included a case with non-firm market prices raised by 20 percent, case #253.

For this case, the non-firm price was 25 percent higher for 1997 compared to the base case. It then increased at 80 percent of the medium gas price escalation rate. Higher non-firm prices affected resource choices through 2005 only slightly (a change in amount of less than two percent). However, higher non-firm prices did affect the amount of non-firm sales and purchases. With higher non-firm prices the model made more non-firm sales: about 900 MWa of sales each year, compared to some 700 MWa in the base case. With higher non-firm prices the model made fewer non-firm purchases: generally less than 40 MWa each year, compared to 40-100 MWa in the base case.

The financial model results for case #43 show average customer prices of 41.57 mills/kWh, compared to the base case of 42.55 mills/kWh. For the years 1997 and 1998, customer prices were lower than they were in

(-2.3%)

↓ price impact

peak = $23.75

off peak $20.00

the base case. The higher non-firm market prices provided more wholesale revenue to offset costs, resulting in lower customer prices.

The next group of nine cases explores the consequences of mis-timing resource needs by either overbuilding or underbuilding capacity. Six cases explore what would happen if PacifiCorp added resources four years ahead of the date new resources would otherwise be added to the system: three cases include a 250 MW plant in 1999 and three include a 500 MW plant in 1999. The last three cases explore the consequences of acquiring too few resources for the first two years of resource need.

Overbuilding

The next six cases address the issue of overbuilding. This would occur if the company acquired a new resource ahead of retail need. RAMPP-3 did not include overbuilding cases.

44)**Overbuilding by 250 MW with Lower Non-Firm Market Prices**
This case added 250 MW of new resources to the existing system in 1999, even though the system does not need new resources until 2003. It assumed that non-firm market prices are 25 percent lower than the medium level assumed in the base case.

45)**Overbuilding by 250 MW with Base Case Non-Firm Market Prices**
This case added 250 MW of new resources to the existing system in 1999, even though the system does not need new resources until 2003. It assumed the base level of non-firm market prices.

46)**Overbuilding by 250 MW with Higher Non-Firm Market Prices**
This case added 250 MW of new resources to the existing system in 1999, even though the system does not need new resources until 2003. It assumed that non-firm market prices are 25 percent higher than the medium level assumed in the base case.

47)**Overbuilding by 500 MW with Lower Non-Firm Market Prices**
This case added 500 MW of new resources to the existing system in 1999, even though the system does not need new resources until 2003. It assumed that non-firm market prices are 25 percent lower than the medium level assumed in the base case.

48)**Overbuilding by 500 MW with Base Case Non-Firm Market Prices**
This case added 500 MW of new resources to the existing system in 1999, even though the system does not need new resources until 2003. It assumed the base case level of non-firm market prices.

49)**Overbuilding by 500 MW with Higher Non-Firm Market Prices**
This case added 500 MW of new resources to the existing system in 1999, even though the system does not need new resources until 2003. It assumed that non-firm market prices are 25 percent higher than the medium level assumed in the base case.

All of the overbuilding cases showed similar results for new resource acquisition at the end of 10 years, because the system had six years (from 1999 to 2005) to return to balance from the over-supply caused by adding resources in 1999. The three cases with 250 MW of overbuilding added 647 MW of gas-fired resources by 2005 under low non-firm prices, 636 MW under medium non-firm prices, and 646 MW under high non-firm prices. The three cases with 500 MW of overbuilding added 645 MW of gas-fired resources by 2005 under low non-firm prices, 635 MW under medium non-firm prices, and 688 MW under high non-firm prices.

Only the cases with base level non-firm market prices should be compared to the base case. Case #42 is the correct comparison for the two overbuilding cases with lower non-firm market prices; case #43 is the correct comparison for the two overbuilding cases with higher non-firm market prices.

The financial results show the impact of various levels of non-firm prices. With 250 MW of overbuilding, average customer prices were 43.43 mills/kWh under low non-firm prices, 42.58 mills/kWh under medium non-firm prices, and 41.64 mills/kWh under high non-firm prices. With 500 MW of overbuilding, average customer prices were 43.53 mills/kWh under low non-firm prices, 42.73 mills/kWh under medium non-firm prices, and 41.74 mills/kWh under high non-firm prices. The amount of overbuilding had less impact than the level of non-firm prices. Whether overbuilding is a wise strategy depends primarily on future prices in the non-firm market. Customer prices for

Comp Case	250	%Δ	500	%Δ
43.39	43.43	<1%	43.53	<1%
42.55	42.58	<1%	42.73	<1%
41.57	41.64	<1%	41.74	<1%

1996, 1997 and 1998 were no different from comparable cases without overbuilding because the overbuilding did not occur until 1999.

Underbuilding

The next three cases addressed the issue of underbuilding. They examined the impact of relying on the non-firm market to meet resource needs during the first two years of expected resource deficit (2003 and 2004). This would delay acquisition of a new resource for two years; instead of acquisition the company could buy the needed power on the market. In 2005 the model could begin making resource acquisitions. RAMPP-3 did not include underbuilding cases.

50)**Underbuilding with Lower Non-Firm Market Prices**
This case assumed 25 percent lower non-firm market prices. The model could purchase energy during the underbuilding years for two mills more than the cost of a combined cycle CT.

51)**Underbuilding with Base Case Non-Firm Market Prices**
This case assumed base case non-firm market prices. The model could purchase energy during the underbuilding years for six mills more than the cost of a combined cycle CT.

52)**Underbuilding with Higher Non-Firm Market Prices**
This case assumed 25 percent higher non-firm market prices. The model could purchase energy during the underbuilding years for 10 mills more than the cost of a combined cycle CT.

The three underbuilding cases added dramatically different amounts of new resources after 10 years compared to the base case. This is because years eight and nine of the 10-year study period were the two underbuilding years, when the model normally would be making resource acquisitions. Instead, for cases #50, #51, and #52, the model relied on the market to meet system needs. The base case added 635 MW of gas-fired resources by 2005. The three underbuilding cases added 278 MW of gas-fired resources by 2005 under low non-firm prices, 274 MW under medium non-firm prices, and 553 MW under high non-firm prices.

The financial results depend heavily on the assumptions about non-firm market prices and the cost of alternative purchased power to meet

Comp Case	Underbuilt	% Δ
43.39	43.68	<1%
42.55	43.03	>1%
41.57	41.79	<1%

resource needs. Under the assumptions used for cases #50, #51, and #52, average customer prices were 43.68 mills/kWh, 43.03 mills/kWh, and 41.79 mills/kWh, respectively, compared to 42.55 mills/kWh in the base case. Customer prices for 1996, 1997 and 1998, were no different from the comparable cases without underbuilding because the underbuilding did not occur until 2003 and 2004. Thus, with the assumed high cost of non-firm power for these underbuilding cases, the results showed that customers were better off with underbuilding only if non-firm market prices were in the high range of expectations. ?

The company assumed that the penalty for underbuilding would be high (two mills above a CCCT in the low non-firm market case, six mills above a CCCT in the base non-firm market case, and ten mills above a CCCT in the high non-firm market case). The company purposefully used relatively high costs for replacement power, recognizing that there are risks to this strategy. The company took a conservative approach of pricing the risk at a high level. If the company had made alternative assumptions, such as a lower penalty, the results would have shown underbuilding to be a more attractive strategy. If the company had assumed it could purchase the power needed at very low prices, for example, the strategy would look very attractive. However, such an approach would have understated the potential risks associated with an underbuilding strategy.

No more than overbuilding.

Transmission

57)**Testing the Transmission Conversion Option**
This case tested the model's capability to add transmission capacity by freeing up capacity on an existing line. It did this by "moving" an existing plant from one region to another, thereby freeing up the transmission capacity formerly used by output from that plant. It had the same effect on the total system and on the movement of power as adding a transmission line. RAMPP-3 did not include a case that used this model capability.

This case offers one approach to evaluating the cost effectiveness of adding new transmission capacity to the system. IPM is not able to represent additional transmission capability as a resource in the portfolio for the model to select. However, it has code that determines the year in which it would be cost-effective to increase the capacity on a transmission path. The model does this through its capability to simulate a geographic relocation of an existing plant from one area to another. This reduces the line load on the old transmission path by the amount of the resource being moved. The year the model selects this option is a good approximation of when it would be cost-effective to add capacity to the transmission system.

Case #57 had two purposes: 1) to verify that this code capability is valid and would select a geographic conversion at some price, and 2) to determine when added transmission capacity would be cost-effective.

All cases had the conversion capability for two existing plants: 1) the Bridger plant in the Bridger area and 2) the Hunter plant in the Utah area. The model could "convert" Bridger to a plant in the Utah area. This simulates an increased capacity on the Bridger-to-Utah transmission path. The model could also "convert" Hunter to a plant in the OWC area. This simulates an increased capacity on the Utah-to-OWC path. These two are bottleneck transmission paths for PacifiCorp.

The company ran several test cases with different prices for the geographic plant conversion. These test cases showed that in order for the model to select this conversion option, the price had to be $180 per kW or less. Therefore, the price used for case #57 was $180/kW. This price is far below the cost of new transmission, and below the cost of upgrades to existing lines in Cases #58 and #59. These upgrade costs were $575/kW and $1,240/kW, respectively.

Using the $180/kW price for a transmission conversion, the model selected 146 MW of the Hunter geographic conversion in 2011 and 157 MW in 2024. Since these results required an unrealistically low conversion cost, and apply after the RAMPP-4 10-year focus period, the action plan does not include any steps to implement a transmission upgrade. The most interesting result is that for case #57, average customer prices went down from 42.55 mills/kWh in the base case to 42.12 mills/kWh. The results indicated that RAMPP-5 should include more analysis of transmission capacity increases.

58) **With 300 MW Added Transmission from Bridger to OWC**

This case increased the transmission path from Bridger to OWC by 300 MW compared to its capacity in the base case. The financial results included the investment required for the expanded path. RAMPP-3 included a case with the same added transmission, case #231.

Same as R-3?

Case #58 assumed the same data as base case #1 with two changes: 1) it provided for an incremental increase of 300 MW on the Bridger-to-OWC transmission path, and 2) it assumed a 300 MW increase in the nomogram (a simultaneous constraint on two paths) that included this path. A nomogram restricts the combined loading on two paths to a specified amount.

The results of this case were almost identical to the base case. The new resources chosen in the first 10 years were the same. Non-firm sales were somewhat higher, but had no appreciable effect.

used $300 in R-3

The financial results included the cost of expanding capacity out of the Bridger area to the OWC area at a rate of $575/kW. Average customer prices for this case were higher than the base case: 43.03 mills/kWh versus 42.55 mills/kWh. The higher prices are due to the $575/kW included for building the new transmission. Since the model didn't change its resource selections, there were no offsetting benefits to these added system costs. 712

59)**With 300 MW Added Transmission from Utah to OWC**

This case increased the transmission path from Utah to OWC by 300 MW compared to its capacity in the base case. The financial results included the investment required for the expanded path. RAMPP-3 included a case with the same added transmission, case #232.

R3 assumed $600

Case #59 used the same data as the base case with two changes: 1) it provided for an incremental increase of 300 MW on the Utah-to-OWC transmission path, and 2) it assumed a 300 MW increase in the nomogram (the simultaneous constraint on two paths) that included this path. The results of this case were almost identical to the base case. The new resources chosen in the first 10 years were the same. Non-firm sales were somewhat higher, but without any appreciable effect.

The financial model included the cost of expanding capacity out of the Utah area to the OWC area at a rate of $1,240/kW. Average customer prices are higher than the base case: 43.05 mills/kWh versus 42.55 mills/kWh. The higher prices were due to the $1,240/kW included for building the new transmission. RAMPP-4 included this case to see if any benefits would accrue from a transmission line from Utah 716

Used $300/kW in R-3

resources to the OWC area. The results show such a line is not cost-effective at current prices and conditions.

The results of cases #57, #58, and #59 reflect the availability of inexpensive gas-fired resources in the western part of the system. New transmission, by comparison, is not cost-effective. As a result, PacifiCorp is not currently planning to build new transmission. However, results imply that the company should take a closer look at transmission in RAMPP-5.

Renewables

61) **With Less Expensive Renewables**
This case artificially lowered the capital cost of new renewable resources by 65 percent. This level of cost reduction was necessary to make renewables cost-competitive with gas-fired resources. If renewable resource developers are able to lower their costs consistent with these assumptions, then this case would represent a possible future. RAMPP-3 included a case that lowered the cost of wind; this was RAMPP-3 case #261.

Under this assumption the model selected 54 MW of renewable resources by 2005. The model also added 200 MW of peaking resources. The amount of DSM selected did not change significantly. The lower cost of renewables reduced the amount of gas-fired resources selected by the model to 364 MW instead of the 635 MW in the base case. The total resource additions in this case were comparable to those of the base case: 1,003 MW versus 1,081 MW.

The financial results for this case show average customer prices of 42.19 mills/kWh, compared to the base case of 42.55 mills/kWh. The assumptions for this case did not significantly affect customer prices in 1996, 1997 and 1998 because the new resource additions tended to occur after that time. Also, the results were similar to those of the base case because the inputs for this case reduced the cost of renewables to the level of gas-fired resources.

Extended Inputs

The next three sensitivities explored the impact of different treatment of key inputs in the end-effect years (the 30 years from 2016 through 2045). These end effect years capture the financial benefits of resources added in the later years of the planning period (in the years close to 2015). In all the other RAMPP-4 cases, the company assumed that all loads, firm wholesale transactions and fuel costs would level out in the 20th year and remain constant through the 30 end-effect years. RAMPP-3 did not include cases that altered the treatment of inputs during the end effects years.

65)**With Extension of All Existing Firm Wholesale Contracts**
This case assumed the company renews all of its existing contracts for firm power, both sales and purchases. The existing contracts would then extend through the planning period.

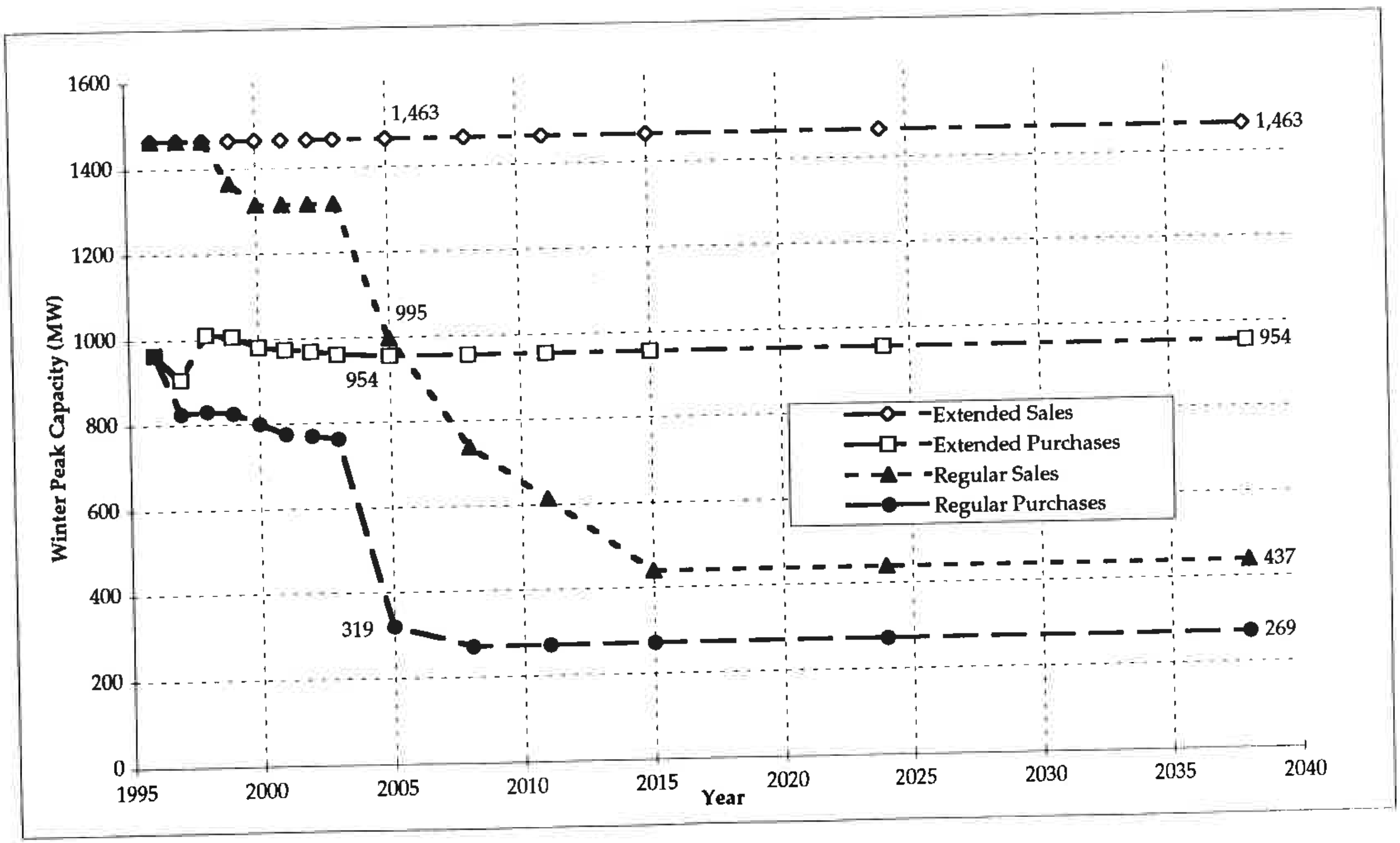
PacifiCorp's current firm wholesale sales and purchases decline as contracts expire. RAMPP modeling usually assumed the parties do not renew the existing contracts. To test this assumption, case #65 assumed that the company will be able to renew or replace its existing contracts with new contracts at the current profit margin. Graph 4-11 shows the impact of extending the existing firm wholesale contracts. The two top lines extended the existing level of purchases and sales through the entire 50-year period. The two bottom lines show the decrease in purchases and sales if existing contracts expire.

Extending the existing contracts had little impact on DSM, which increased by only 13 MW. However, total new baseload additions increased from 635 MW in the base case to 1,101 MW in this case. Extending the contracts tended to require additional resources to meet the 12 percent summer reserve margin requirement. While the summer reserve margin remained at 12 percent, the winter reserve margin increased from 15.1 percent in the base case to 20.8 percent in case #65.

Financial results required estimating the revenue stream for the extended sales as well as the cost stream of the extended purchases. The financial model results for this case indicated average customer prices of 42.35 mills/kWh, compared to 42.55 mills/kWh in the base case.

Extended Firm Purchases and Sales

Graph 4-11



66)**With Extension of Load Growth and DSM Through End-Effect Years**
This case allowed load growth and DSM to continue for the entire 50 years, rather than stopping at the end of the first 20 years.

Case #66 extended load growth through 2045 and allowed the model to continue selecting more DSM, as shown in Graph 4-12. Extending loads and DSM had little effect through 2005, but had considerable impact in the end-effect years, 2015 to 2045.

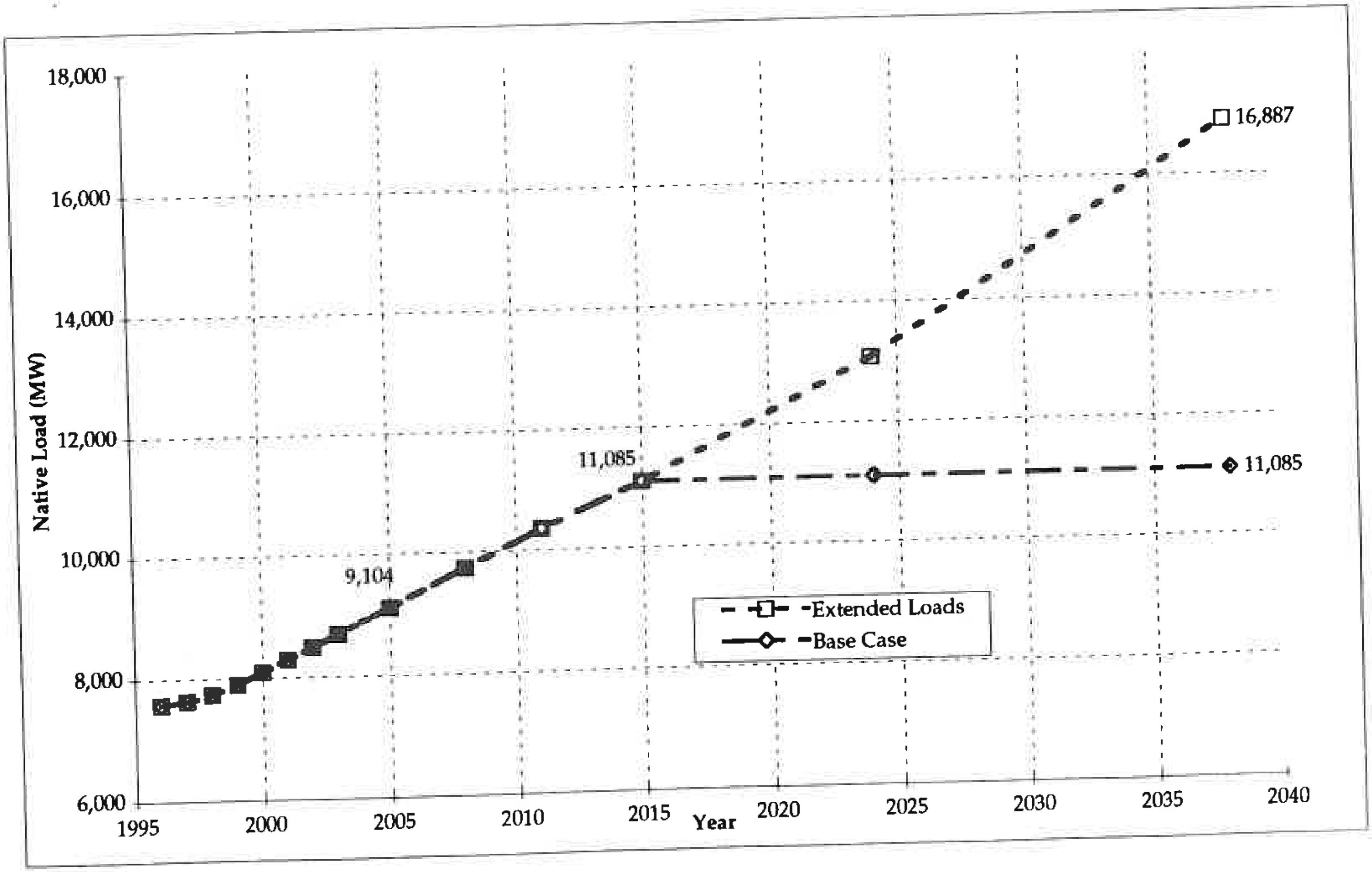
The financial model results for case #66 show average customer prices of 40.69 mills/kWh compared to 42.55 mills/kWh in the base case. The decline in average customer prices occurred because additional load growth in the end-effect years permitted the model to add more DSM and more cost-effective gas-fired resources, and spread the cost over more kWhs.

67)**With Extension of All Inputs**
This case allowed load growth, DSM, gas price escalation, and firm contracts to continue through the end of the 50 years.

Case #67 combines cases #65 and #66 with the continued escalation of fuel prices to 2045. Graph 4-13 shows the extension of gas price escalation to 2045. This effectively extends all key modeling inputs to 2045. Extending all modeling inputs produced resource selection results by 2005 that were virtually identical to those in case #65. Financial results were virtually identical to those in case #66. The cases show that extending existing wholesale contracts has an immediate impact on resource selection; that extension of loads and DSM has financial impacts in the end-effect years; and that extending gas price escalation has no significant impacts on its own.

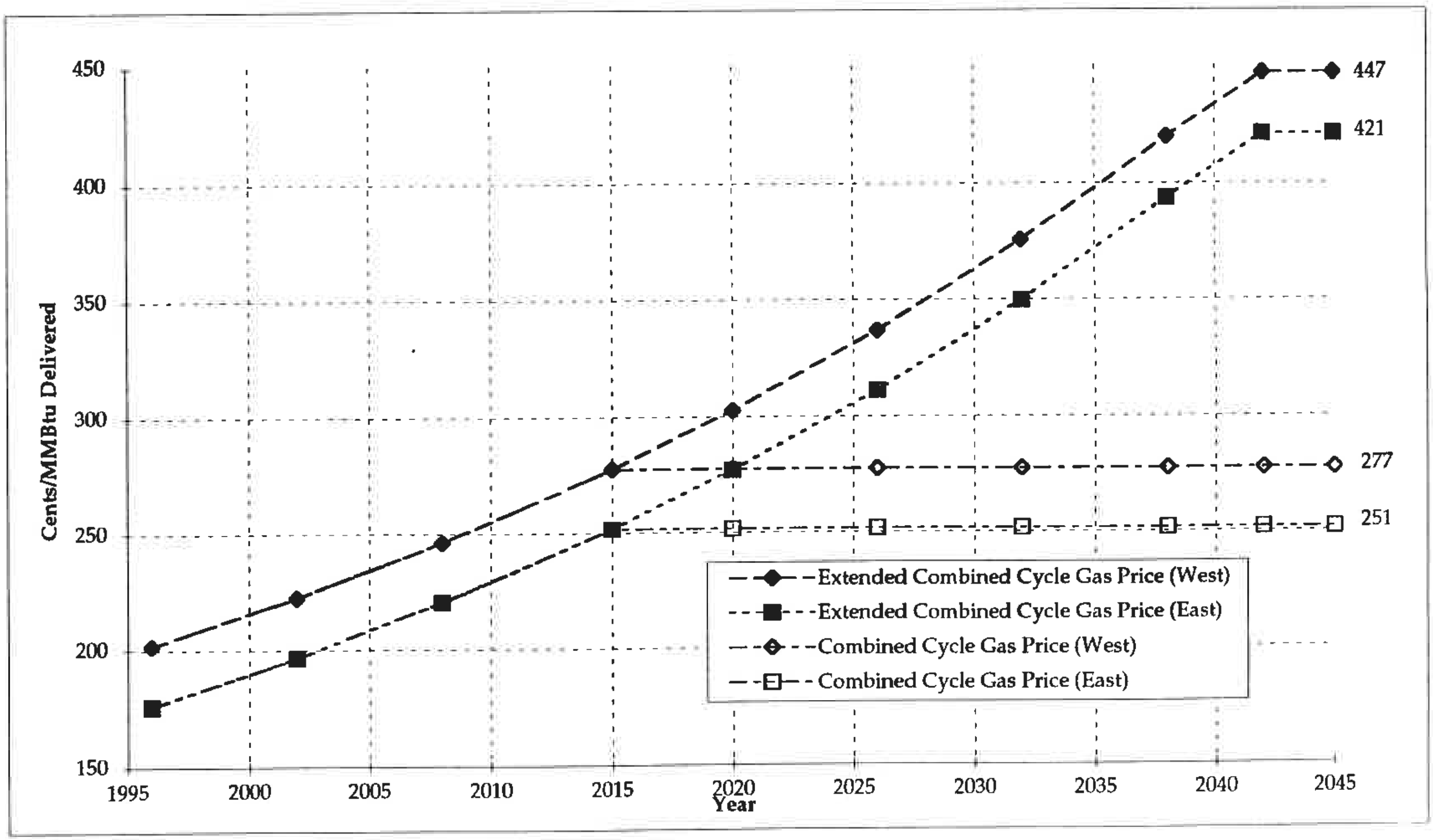
Extended Load Growth and DSM

Graph 4-12



Extended Gas Prices

Graph 4-13



Environmental Adders Cases

The environmental adder cases included three sensitivities that tested the impact of externality costs on system planning. In each case, PacifiCorp converted the environmental adder to a mills/kWh value and added it to the variable cost of existing and potential resources. Wholesale purchases used the adder for gas-fired resources. The financial model did not include the environmental adder as a tax; it only included the added system costs of reconfiguring and operating the system to minimize the environmental adder tax.

The environmental adder values are from the Oregon Public Utility Commission Proceeding UM 424. The UM 424 Order specified six levels of environmental externality adders that utilities should use in their least cost plans. RAMPP-3 included 21 cases using the six levels under alternative futures. To avoid repetition from RAMPP-3, RAMPP-4 included only three externality cases, which cover the range of adder values. The three listed below are most comparable to cases #301, #302, and #306 from RAMPP-3. The company did not adjust the adder amounts for inflation since the date of the UM 424 Order. Adjusting the adders for inflation would not significantly change the insights gained from these cases.

Table 4-14 shows the impact of environmental adders on portfolio costs. The table lists the resources in order of increasing costs. It numbers the five least expensive resources under the conditions in the base case and under each of the three adder levels. The gas-fired adders are, from lowest cost to highest, about four mills, 10 mills, and 16 mills. The lowest level of environmental adders changes the ranking only slightly. It reshuffles the resources in positions 2, 3, and 4. The medium level of adders reshuffles the order of all five of the top resources. The high adder level only keeps two of the original top five resources (cogeneration in OWC) and added wind and geothermal. Adders must reach the high level (16 mills for gas-fired resources) to make the renewables appear more cost-effective.

Graph 4-15 shows the resource additions for each of the adder levels from 1996 to 2005. All of the environmental adder sensitivities selected more gas-fired resources than needed for the reserve margin. The additional resources reduced the dispatch of existing coal-fired resources, thus reducing emissions. This resulted in higher reserve margins in these cases and higher customer prices.

Impact of Environmental Adders on Portfolio Costs (in 1996$)

Table 4-14

Short Name	Description	Base Case		Low Adders Case 71		Med Adders Case 72		High Adders Case 73	
		Rank Lowest Five	Resource Cost Mills/kWh	Rank Lowest Five	Resource Cost Mills/kWh	Rank Lowest Five	Resource Cost Mills/kWh	Rank Lowest Five	Resource Cost Mills/kWh
UD1	Utah Gadsby Repower	1	24.19	1	28.97	2	35.92		43.07
UC2	Utah Cogen 2	2	26.05	3	30.19	4	36.21		42.41
OC2	OWC Cogen 2	3	26.15	4	30.29	5	36.31		42.51
OC1	OWC Cogen 1	4	26.44	2	29.79	1	34.65	3	39.67
UC1	Utah Cogen 1	5	27.83	5	31.18	3	36.05	4	41.06
UCC	Utah Combined Cycle		29.64		34.22		40.87		47.73
OCC	OWC Combined Cycle		29.75		34.33		40.98		47.84
WCC	Wyo Combined Cycle		30.39		34.97		41.62		48.48
UG1	Utah PC Hunter 4		31.47		42.99		58.54		75.74
WG1	Wyo PC Wyodak 2		32.32		45.94		64.33		84.68
WG2	Wyo Coal $6.70/Ton		34.35		46.67		63.29		81.69
UCY	Utah IGCC Hunter 4		35.74		45.35		58.33		72.70
UG2	Utah Coal $23.25/Ton		36.27		47.80		63.34		80.55
WCY	Wyo IGCC Wyodak 2		36.42		46.59		60.31		75.50
WCZ	Wyo IGCC CT		36.52		46.69		60.41		75.60
UCZ	Utah IGCC CT		37.98		47.60		60.58		74.94
UG3	Utah Coal $27.00/Ton		38.04		49.56		65.11		82.32
UW1	Utah Wind Non-firm		38.78		38.78		38.78	1	38.78
WW1	Wyo Wind Non-firm		38.78		38.78		38.78	2	38.78
OGT	OWC Geothermal		41.66		41.66		41.66	5	41.66
UGT	Utah Geothermal		41.66		41.66		41.66	5	41.66
UW2	Utah Wind Firm		48.25		48.25		48.25		48.25
WW2	Wyo Wind Firm		48.40		48.40		48.40		48.40
OW1	OWC Wind Non-Firm		49.18		49.18		49.18		49.18
OW2	OWC Wind Firm		56.99		56.99		56.99		56.99

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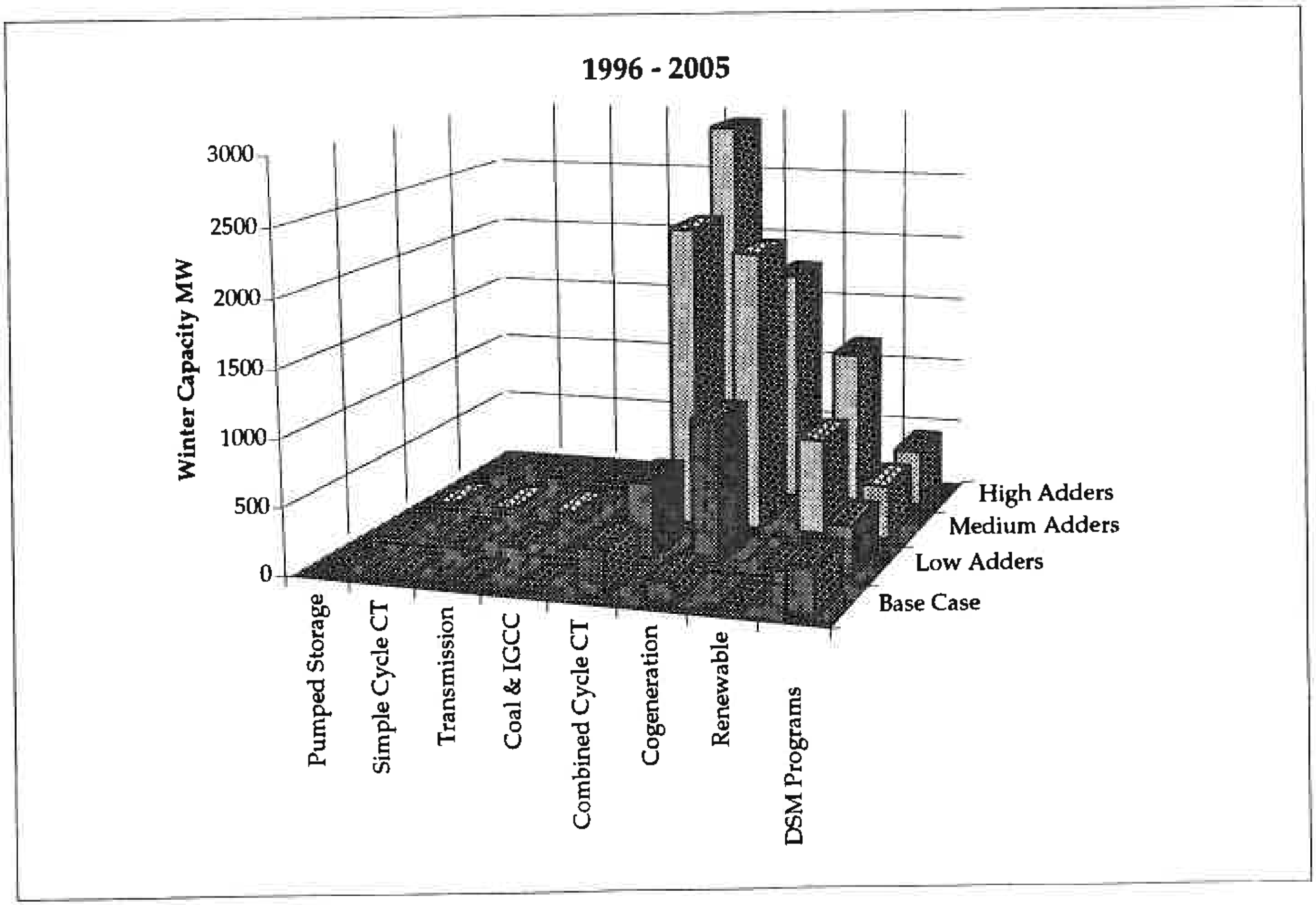
Resource Additions by Environmental Adders

Graph 4-15



71) **With Low Adders**

This case used the lowest of the six levels of externality costs specified in OPUC UM 424 (low NOx and TSP, $10/ton CO2). It increased the cost of all resources that have these emissions.

The environmental adder in the low environmental adder case was $10/ton for carbon dioxide and $2,000/ton for NOx and TSP. Under this assumption, the model increased DSM to 462 MW by 2005 (compared to 446 MW in the base case). The model selected 1,379 MW of gas-fired resources compared to only 635 MW in the base case.

The winter reserve margin in case #71 grew to 23.1 percent compared to 15.1 percent in the base case. This occurred as the model added gas-fired resources to replace existing coal-fired resources. Renewable resources were not cost-effective at the low environmental adder level.

The financial results for case #71 show average customer prices of 43.74 mills/kWh, compared to the base case of 42.55 mills/kWh. For 1996, 1997 and 1998, customer prices were one to two mills higher than the base case. Average annual CO2 emissions declined by 10.3 million tons per year from the base case level. Average annual emission of NOx declined by 34,000 tons per year from the base case level. The estimated cost of reducing CO2 emissions through reconfiguring the system was $107 per ton.

72) **With Medium Adders**

This case used a medium level of the six levels of externality costs specified in OPUC UM 424 (low NOx and TSP, $25/ton CO2). It increased the cost of all resources that have these emissions.

The environmental adder in the medium environmental adder case was $25/ton for carbon dioxide and $2,000/ton for NOx and TSP. DSM selected by 2005 increased from 446 MW in the base case to 509 MW. Gas-fired resources increased from 635 MW in the base case to 4,124 MW by 2005. At this level the model displaced most but not all of the company's existing coal-fired resources with new gas-fired resources. Renewable resources became cost-effective at the medium environmental adder level, and the model added 500 MW of geothermal and 400 MW of wind.

The financial results for case #72 show average customer prices of 52.84 mills/kWh compared to 42.55 mills/kWh in the base case. Customer prices in 1996, 1997 and 1998, were about 2.5 to 3 mills higher than in the base case. Average annual CO2 emissions declined by 30.2 million tons per year from the base case level. Average annual emission of NOx declined by 93,000 tons per year from the base case level. The estimated average cost of reducing CO2 emissions from the base case level to the level in case #72 was $325 per ton. The incremental cost of reducing CO2 emissions from the level in case #71 (low adders) to the level in this case was $437 per ton.

73)**With High Adders**
This case used the highest of the six levels of externality costs specified in OPUC UM 424 (high NOx and TSP, $40/ton CO2). It increased the cost of all resources that have these emissions.

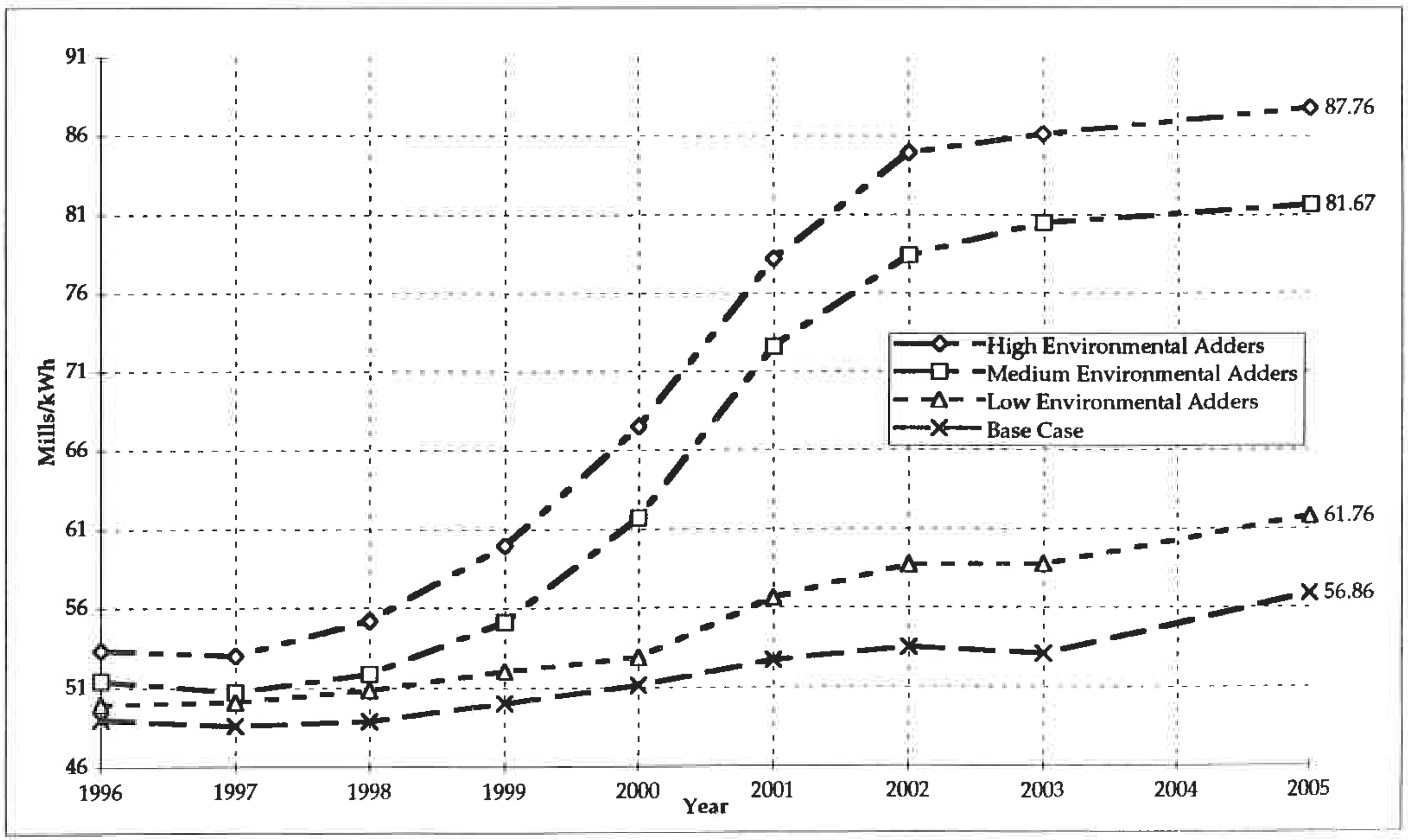
The environmental adder in case #73 was $40/ton for carbon dioxide, $5,000/ton for NOx and $4,000 for TSP. This is the highest possible combination of environmental adders in the UM 424 Order. DSM increased in this case from 446 MW in the base case to 537 MW by 2005. Gas-fired resources increased from 635 MW in the base case to 4,475 MW by 2005. At this adder level, the model displaced virtually all of the company's existing coal-fired resources with new gas-fired resources. The model selected all of the geothermal resources identified in the portfolio (600 MW) and all of the wind resources eligible for the federal tax credit (1,200 MW). The model did not select wind that was ineligible for the federal tax credit.

The financial results for the case using high environmental adders show average customer prices of 56.16 mills/kWh compared to 42.55 in the base case. Average annual CO2 emissions declined by 34.6 million tons per year from the base case level, to 20.6 million tons. Average annual emissions of NOx declined by 103,000 tons per year from the base case level, to 22,000 tons per year. The estimated average cost of reducing CO2 emissions from the base case level to the level in case #73 was $376 per ton. The incremental cost of reducing CO2 emissions from the level in case #72 (medium adders) to the level in this case was $733 per ton.

Graph 4-16 shows the yearly nominal prices for the base case and each of the adder cases. The impacts didn't become enormous until after the first four years of the planning period, and then only for the medium

Yearly Nominal Mills/kWh of Utility Cost
By Environmental Adder Level

Graph 4-16



and high adder cases. The low adder cases would increase customer prices somewhat (by about three percent on average). The medium and high adder levels would dramatically increase customer prices, to more than 80 mills/kWh by 2005. This would be almost a 100 percent increase in prices. The company believes there are less expensive ways, such as carbon offsets, to mitigate the emissions of fossil-burning plants.

PacifiCorp's overall strategy to reduce emissions used three approaches: cost-effective demand-side programs, cost-effective renewable projects, and carbon offset projects. These aim to reduce absolute emissions from otherwise prevailing levels, to reduce the omissions rate (CO_2/kWh) associated with electricity production, and to offset a portion of remaining CO_2 emissions. PacifiCorp's offset programs include tree planting, forest protection, ethanol production, and coal recycling.

Comparisons to RAMPP-3

This section addresses the lessons learned from the analyses and their comparison to the results from RAMPP-3. The RAMPP-4 Action Plan chapter links the modeling results to the action plan items. The following discussion addresses each of these points:

- A need for fewer resources
- Less DSM than the medium level from RAMPP-3
- Higher gas price escalation need not lead to higher retail prices
- Switch from coal-fired as least-cost supply-side resource to least-cost gas-fired – Due to input price assumptions
- Summer-only peak purchase
- Higher load growth need not cause higher prices — as long as non-firm ...
- Hermiston reduces costs
- Non-firm market prices important for customer prices

- Overbuilding and underbuilding strategies depend on non-firm prices

- Added transmission not cost-effective

- Fewer renewables

- Environmental adders add significantly to customer prices

A Need For Fewer Resources

RAMPP-4 showed a need for fewer new resources than RAMPP-3. This is due to four primary changes: reduced load forecast, lower reserve margin, the addition of the Hermiston plant, and the turbine upgrades. The net effect of the load forecast changes on the system was a decrease in system load of 536 MW by the year 2005. The net effect of the change in the reserve margin was a reduction in system needs of 300 MW by 2005. Adding Hermiston to the existing system added 474 MW. The turbine upgrades added 150 MW to the existing system.

Less DSM Than the Medium Level from RAMPP-3

RAMPP-4 added less DSM than RAMPP-3 at the medium DSM level. This was due to two primary changes: lower system needs, and the lower costs of new supply-side resources that were competitive with DSM. The lower system needs occurred for the reasons described above. The lower costs of new supply-side resources (gas-fired baseload resources) reduced the level of DSM that was cost-effective. Because the model did not select the amount of DSM in RAMPP-3, the company does not know how much DSM the model would have selected. We do know that the amount that is cost-effective today is less than the medium level from RAMPP-3.

Higher Gas Price Escalation Need Not Lead to Higher Retail Prices

In RAMPP-3 three natural gas price escalation rates covered a likely range from a low of 1.7 percent real annual escalation, medium of 3.8 percent, and high of 5.6 percent. RAMPP-4 used lower escalation rates: low of zero percent, medium of 2.1 percent, and high of 3.8 percent. The 1996 price for gas in RAMPP-4 was about 36 percent lower than the 1996 price for gas in RAMPP-3. In both cases, the analysis included the commodity cost, transportation charges, transportation demand charges, storage demand charges, and storage injection and withdrawal charges.

The results of cases #31-34 in RAMPP-4 were very similar to the results for a comparable analysis in RAMPP-3: changing the gas price escalation rate did not dramatically change the resources selected, although a lower gas price escalation increased the model's selection of gas-fired resources; and higher gas price escalation reduced the model's reliance on gas-fired resources. In RAMPP-4, changing the gas price changed the amount of DSM the model selected. This did not occur in RAMPP-3 because altering the amount of DSM was not available to the model.

In both planning cycles, gas price escalation had little impact on customer prices. This is partially because of the correlation between gas price escalation and non-firm market prices. If gas price escalation is higher, PacifiCorp is able to make more money selling power on the non-firm market because those non-firm market prices are higher. PacifiCorp's access to the non-firm markets improves its ability to respond to gas price uncertainty. The lower cost of new resources due to lower gas price escalation offsets the corresponding loss in non-firm revenue. Therefore, it appears the company can manage its resource activities to minimize retail price risk from gas price uncertainty. As long as the company is successful in the wholesale market, and non-firm market prices continue to correlate highly with gas price escalation, customers should not suffer higher electricity prices from higher gas price escalation.

The company believes the assumption of a correlation between gas price escalation and non-firm market prices will remain valid as long as gas-fired resources remain the marginal resource in the wholesale market. If this relationship should change, the next RAMPP cycle can incorporate that change.

Switch From Coal-Fired as Least-Cost Supply-Side Resource to Least-Cost Gas-Fired

RAMPP-3 added coal-fired resources to meet baseload needs because coal-fired resources were the least-cost supply-side resource in RAMPP-3. RAMPP-4 added gas-fired resources because they were the least-cost supply-side resource. This occurred because coal costs increased and gas costs decreased in RAMPP-4. In RAMPP-3 gas-fired resources cost about 10 mills/kWh more in real levelized total resource cost than did coal-fired resources. In RAMPP-4 gas-fired resources cost about 6 mills/kWh less than did coal-fired resources.

Summer-Only Peak Purchase

RAMPP-3 selected year-round resources to meet peaking needs; RAMPP-4 selected summer-only peaking resources. The change occurred for two reasons: RAMPP-4 recognized the summer peak season, and a summer-only peak purchase was available in the portfolio of new resources in RAMPP-4. RAMPP-3 recognized only one peak season -- winter, and no seasonal peak purchase option was in the portfolio. RAMPP-4 recognized both winter and summer peak needs, which allowed for the possibility of needs occurring in one season ahead of the other. This occurred in RAMPP-4 when the system needed summer peaking resources before winter peaking resources (since the system has more winter peaking resources).

Higher Load Growth Need Not Lead to Higher Prices

RAMPP-3 included five load growth levels from a low of 0.3 percent to a high of 3.75 percent annual growth over the next 20 years. The medium load growth case was 2.1 percent. RAMPP-4 included three load growth levels from a medium-low of one percent to a medium-high of three percent. The medium load growth case was two percent. The results from RAMPP-3 showed that both medium-low and low load growth caused the same pattern of results: pushing off the timing for resource needs well beyond the need for any decisions in the action plan period. The same would be true for a negative load growth case. Therefore, the company did not include a low load growth case nor a negative load growth case in RAMPP-4. The results from RAMPP-3 showed that both medium-high and high load growth caused the same pattern of results: needs occurring sooner but selection of the resource technologies did not change. Therefore, the company did not include a high load growth case in RAMPP-4. As discussed below in the benchmarks section, the company will be carefully watching load growth, as well as load changes from customers leaving or new customers coming on the system, and review the action plan as needed.

The medium-low load growth and medium-high load growth cases in RAMPP-4 confirmed a conclusion in RAMPP-3 that higher load

1994 actual embedded - 33 mills
margin - 20 mills

growth did not increase average customer prices and lower load growth did increase average customer prices. As load growth increased, customer prices in real terms generally stayed constant or decreased, indicating that the company can meet the new resource needs caused by load growth with price increases that are no greater than inflation (inflation assumed to be 3.3 percent). The company believes that lower load growth can lead to higher prices because the system operates less efficiently when it is not fully used. Higher load growth can lead to lower prices because it results in more efficient use of the existing system, and because the cost of new resources is very close to the average embedded cost of existing resources. The results of the three load growth levels indicate that usage of the system increases at higher load growth. For the three years before the model added new resources in any of the load growth cases (1996-1998), the average usage of the existing system is 7,341 MWa under medium-low load growth, 7,419 MWa under medium load growth, and 7,472 under medium-high load growth.

The finding that load growth leads to lower retail customer prices in RAMPP-3 was contrary to the findings about load growth from RAMPP-2. The company believes there are three reasons for the lower price results in RAMPP-3.

First, modeling techniques in RAMPP-2 did not include an optimization model, so resource additions did not always exactly match the reserve margin requirement (they often exceeded it), resulting in excess additions and thus higher costs than optimally necessary for some years. RAMPP-3 used an optimization model that added only the exact amount of resource needed, regardless of whether it was only a portion of a plant. This removed any lumpiness from resource additions, lowering the costs for many of the years.

Second, the company recognized that significantly more low-cost cogeneration was available from industrial customers when preparing the RAMPP-3 input assumptions than was the case with RAMPP-2. In RAMPP-2 the model only had 400 MW of low-cost cogeneration, whereas in RAMPP-3 it had 2,100 MW of low-cost cogeneration.

Third, fuel price assumptions changed, causing generally lower costs for RAMPP-3.

Based on the RAMPP-4 load growth cases, the company concluded that a small change in projected load growth (of one percent) has a large effect on the need for new resources over the next 10 years. Because a small change can have a big impact, and load can change unexpectedly, the company believes in watching the benchmarks identified in Chapter 6 and having a flexible action plan.

Hermiston Reduces Costs

In RAMPP-3 Hermiston was not part of the existing system; in RAMPP-4 Hermiston was in the existing system. RAMPP-4 included three cases to test the cost-effectiveness of Hermiston by removing Hermiston from the existing system and letting the model select alternative resources with alternative timing. These three cases used medium load growth and three different levels of gas price escalation. RAMPP-4 case #6 used medium gas price escalation, RAMPP-4 case #7 also removed Hermiston but used high gas assumptions, and the company added a no-Hermiston low gas case to the RAMPP-4 analyses.

All three RAMPP-4 cases without Hermiston resulted in higher customer prices than the base case with Hermiston. The company believes this is primarily because of a strategy of successfully selling any excess power in the wholesale market, which reduces total system costs and customer prices. This confirmed the conclusion reached in RAMPP-3 cases #212 and #213 where costs declined when Hermiston was included.

Link to Non-Firm

Non-Firm Market Prices Important for Customer Prices

The most comparable cases in RAMPP-3 to cases #42 and #43 above were cases #252 and #253. They altered the price of non-firm power by 20 percent more or less than the base case, whereas RAMPP-4 altered the price by 25 percent. The RAMPP-3 cases showed that a reduced non-firm market price had very little effect on resource choices, but it increased customer prices. A higher non-firm market price had a minor impact on resource choices and reduced prices. The RAMPP-4 cases showed the same pattern. Altering the non-firm price had a minor impact on resource choices (69 MW more of gas-fired resources with lower non-firm prices, and 15 MW more of gas-fired resources with higher non-firm prices). Lower non-firm prices increased customer prices; higher non-firm prices lowered customer prices.

The company successfully uses the non-firm markets to buy and sell power, using the revenues to reduce the total revenue requirement for retail customers, and thereby reducing customers' retail prices. Neither load growth nor gas price escalation had much impact on the model's activity in the non-firm markets. In both planning cycles variation in non-firm prices had a minor impact on the amount of new resources selected, but it had a noticeable impact on customer prices.

Consistently, both the RAMPP-3 cases and the RAMPP-4 made more sales than purchases. Graph 4-17 shows the average amount of non-firm transactions based on the level of non-firm market prices in RAMPP-4. Included are the amounts for sales and purchases; then the net of sales minus purchases. The scales for sales and purchases are different: sales reached a maximum of more than 800 MWa, whereas purchases reached a maximum of just over 180 MWa.

The company makes more non-firm sales than it does non-firm purchases, so that net non-firm transactions are sales. Graph 4-17 shows that the level of non-firm prices mainly affected the company's profitability from non-firm sales, and thus the overall system costs and customer prices. A reduced non-firm market price increased system costs and customer prices. A higher non-firm market price reduced ~~costs and prices.~~ average utility cost/kWh Graph 4-18 shows the impact on customer prices of differences in the non-firm market price. Higher non-firm market prices help reduce customer prices. These results are consistent with the RAMPP-3 results.

The non-firm market sensitivities illustrate the importance of using reasonably accurate estimates of prices on the non-firm market. The lesson for PacifiCorp is that the IRP process must use a model that can recognize and use the non-firm market as the company does for daily operations. This allows the model to accurately reflect PacifiCorp's use of the non-firm market to minimize system costs and minimize customers' retail prices.

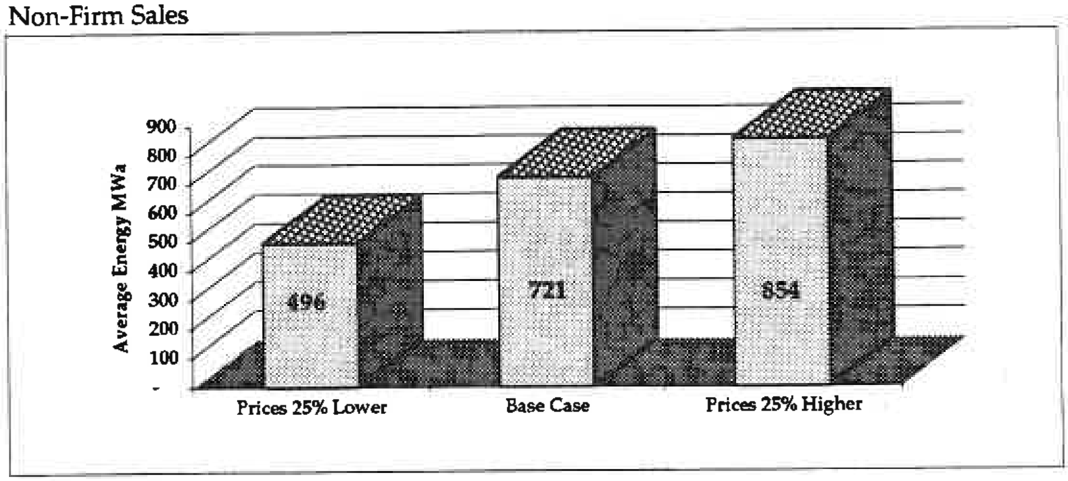
Overbuilding and Underbuilding Strategies Depend on Non-Firm Prices

RAMPP-3 did not include cases on overbuilding and underbuilding. In RAMPP-4, overbuilding by 250 MW or by 500 MW would reduce average customer prices if non-firm prices are relatively high; it could increase average customer prices if non-firm prices are low.

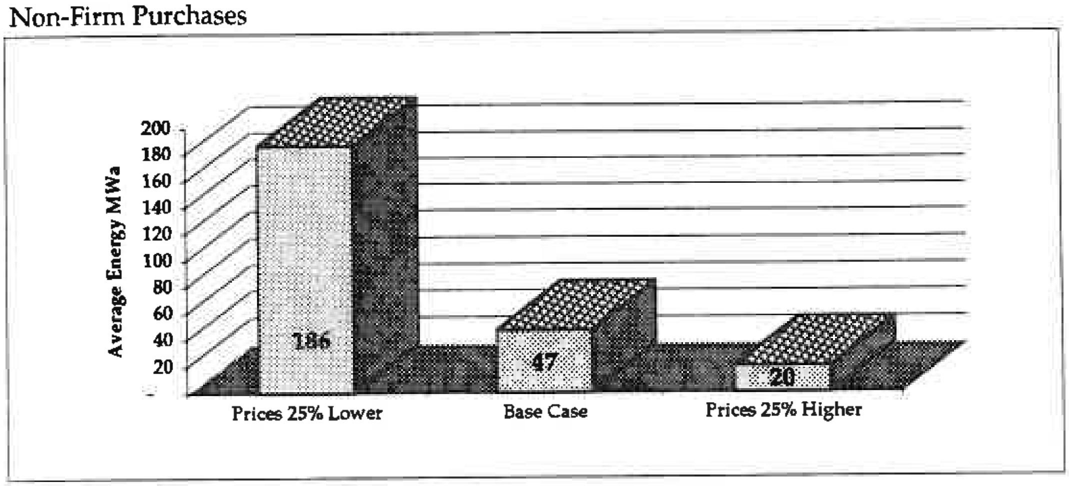
Average Non-Firm Transactions by Non-Firm Price Level

Graph 4-17

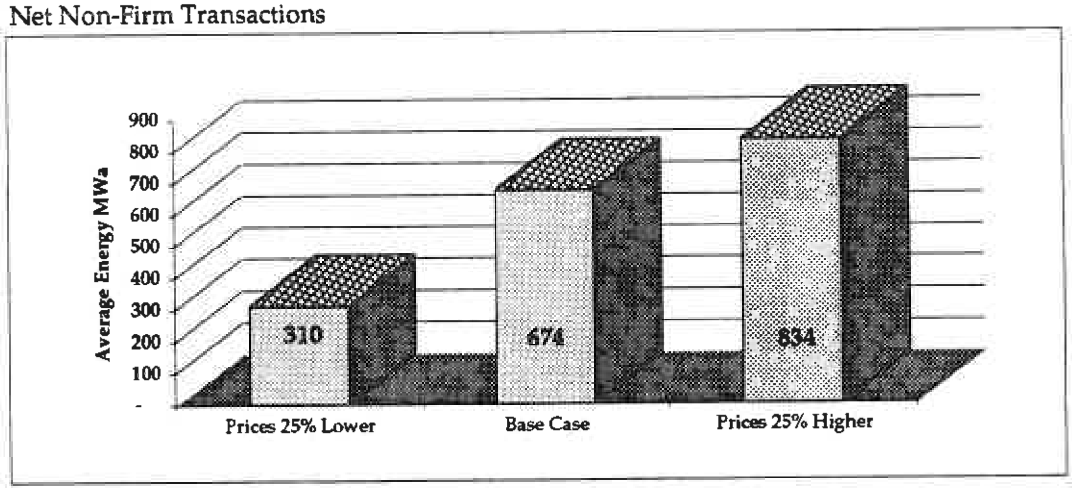
Non-Firm Sales



Non-Firm Purchases

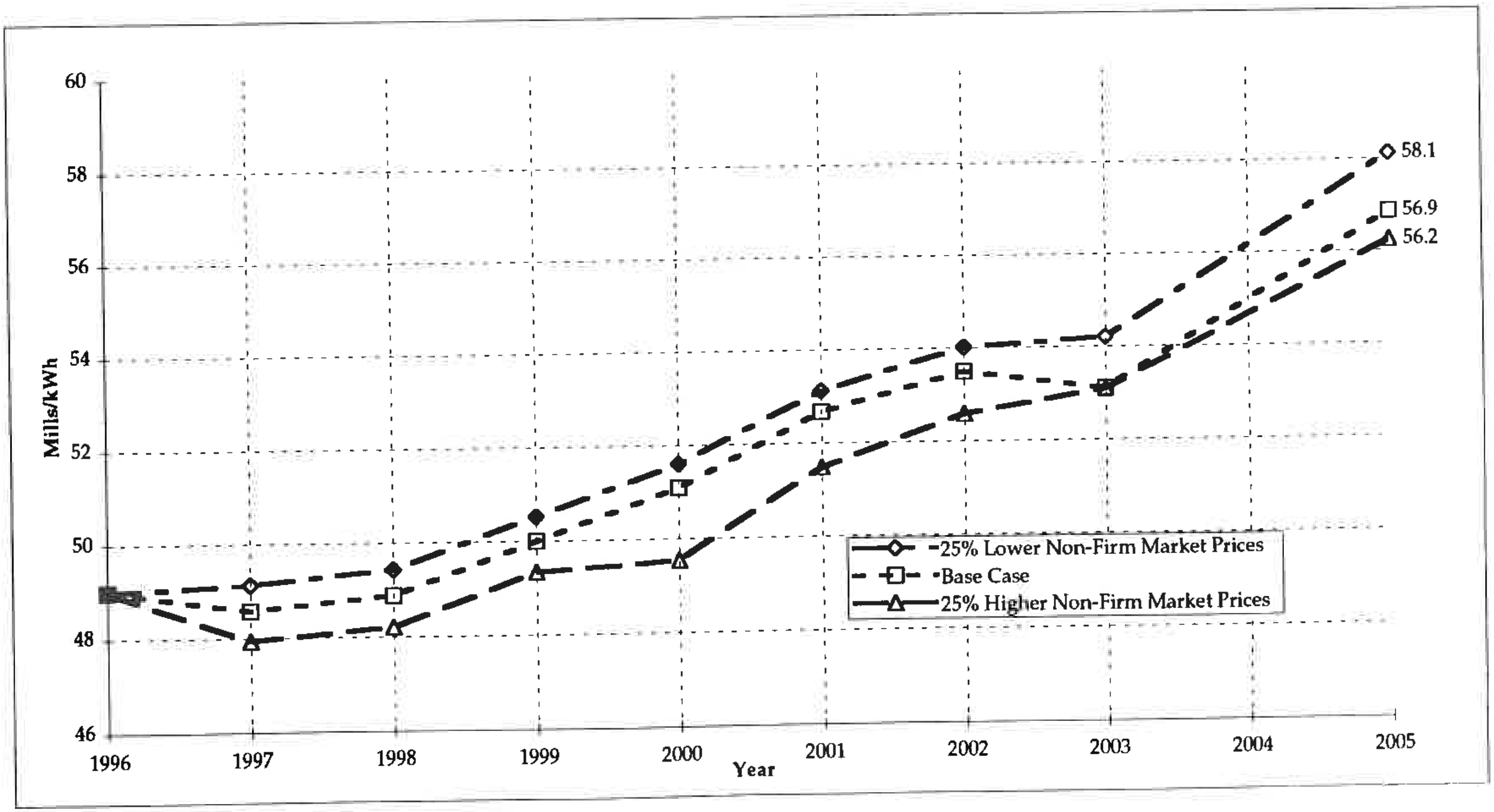


Net Non-Firm Transactions



Yearly Nominal Mills/kWh of Utility Cost
By Non-Firm Market Prices

Graph 4-18



The impact of any strategy of overbuilding and the impact of the amount of overbuilding depends primarily on the level of non-firm prices in the years following the overbuilding activity. Overbuilding is not the key determinant of prices; instead, the level of non-firm prices determines how overbuilding affects customer prices.

The impact of underbuilding depends on the assumptions made about the availability and cost of alternative purchased power to meet resource needs. The company assumed a relatively high cost for purchased power, thus perhaps over-estimating the risk of an adverse financial impact. However, the company did not want to under-estimate the risk of this strategy.

Added Transmission Not Cost-Effective

Transmission is increasingly constrained as utilities grow and wholesale transactions increase. To test the impact of these constraints, the analysis in both RAMPP-3 and RAMPP-4 included two sensitivities that expanded the capacity of two key paths (from Wyoming to OWC and from Utah to OWC). Both increased capacity from the eastern part of the system to the western part of the system, reducing PacifiCorp's primary transmission constraint. In RAMPP-3 these two cases lowered customer prices. In RAMPP-4 these two cases raised customer prices. The change in results is due to two factors. The first reason is the presence of the Hermiston plant in the OWC area, which provides additional resource on the western part of the system. The second reason is the switch from coal-fired being the least-cost supply-side resource (located on the eastern side of the system, which is transmission-constrained) to gas-fired being the least-cost supply-side resource (located on the western side of the system, which is not transmission-constrained).

In RAMPP-4 the company used a second method to evaluate the need for additional backbone transmission capacity. The geographical conversion option "moves" an existing resource from one geographic area to another. When the model selects a geographical conversion it has the same effect as increasing the capacity of the transmission path between the original area and the conversion area. The model selected the geographic conversion of an existing plant in only one sensitivity: case #57. For this case the company lowered the cost of the conversion until the model selected it. However, the cost used in this case is far below the actual cost of adding to transmission capacity. This was confirmation that expanding transmission capacity is not a cost-effective choice at this time.

The company concluded from these results that transmission upgrades between regions are not cost-effective at this time. Adding to the backbone transmission system would have almost no effect on resource choices, but would increase average customer prices. Given these results, the company did not include a transmission action item in the RAMPP-4 action plan. PacifiCorp will take a closer look at transmission in RAMPP-5.

Fewer Renewables

Several sensitivities in RAMPP-3 determined that if the company's base assumptions about renewable resource costs and operating characteristics were inaccurate, the errors would have to be quite large to alter the model's resource selections. Analysis in RAMPP-4 revealed that the capital cost of renewable resources must be 65 percent lower than they are currently before renewables become competitive with gas-fired resources. The results of the renewable case in RAMPP-4 confirmed the conclusion from RAMPP-3 that renewables are not cost effective at this time. The renewable industry needs to significantly reduce their costs before renewable resources will be cost-competitive.

Environmental Adders Add Significantly to Customer Prices

Both RAMPP-3 and RAMPP-4 included cases that used environmental adders that increased the cost of fossil-fuel-fired resources. PacifiCorp believes the risk of future internalization will remain low for several years. Also solutions found through an adders approach are not necessarily the least-cost solution to reducing emissions. The company believes that offsets can provide a way to find least-cost solutions to emissions management. Several pilot projects are helping the company to gain a better understanding of how offsets can work. The Action Plan chapters provide more information about the company's offset projects.

The environmental adder results from RAMPP-3 do not directly compare with the results of the adder cases from RAMPP-4 because of changes in modeling. However, the general results appear to be consistent. The most significant change from RAMPP-3 to RAMPP-4 was the reduction in natural gas prices and gas price escalation rates.

This change made gas resources the resource of choice in RAMPP-4, which has lower emissions than pulverized coal, the resource of choice in RAMPP-3. The use of environmental adders in RAMPP-3 moved resource choices from pulverized coal technology to coal gasification, toward cogeneration and renewables. In the RAMPP-4 cases with environmental adders the model stayed with gas-fired resources at the lower adder levels and moved toward renewables at the higher adder levels.

In RAMPP-3 PacifiCorp assumed an unlimited availability of wind resources. As a result, in the RAMPP-3 environmental adder cases, the model chose very large amounts of wind. In RAMPP-4, the inputs included much lower wind availability. As a result, the model selected less wind than in RAMPP-3. In both of the RAMPP-4 cases that selected wind, the model did not select all of the wind that was available. It selected all of the less expensive wind (not requiring additional transmission investment), but not all of the more expensive wind (requiring transmission investment).

RAMPP-3 included a "must run" feature for the company's existing coal-fired resources, which did not allow the model to reduce the dispatch of those resources as the model could in RAMPP-4. In RAMPP-4 the model could, and did, reduce the dispatch of existing coal-fired plants in the environmental adder cases. When the inputs to the model were adder-adjusted prices of the company's existing coal-fired generation, it shut down production from the existing system and added new resources with lower adder-adjusted costs. As a result, in RAMPP-4 the model added more gas-fired resources to replace the output that otherwise would have come from existing coal-fired resources. The model also increased non-firm purchases, because they carried adders for gas-fired resources that are lower than the adders for coal-fired resources.

The company chose not to escalate the adders from 1990 to 1996 dollars. Escalation would have increased the adder cost by 22 percent for RAMPP-4 assuming a 3.3 percent annual inflation factor. An adjustment of this size would make low-emission resources even more attractive relative to higher-emission resources. A likely result would be lower dispatch of existing units, more selection of low-emission resources, earlier selection of these low-emission resources, lower sales of non-firm energy, and more purchases of non-firm energy. Although the results would have been slightly different, the insights that the company gained from the runs remain unchanged. Furthermore, the change would not have changed the insights that came out of RAMPP-3. Finally, the company feels that the \$10 to \$40 range for a CO2 adder provides an adequate test to evaluate environmental concerns.

Table 4-18 shows which factors had the most impact on emissions in the RAMPP-4 cases: the environmental adders, load growth, non-firm market prices, lowered cost of renewables, the turbine upgrades, and the no-DSM case. The adders had the most impact on emissions, reducing them by up to 80 percent. This is because the adder cases shut down the existing system and purchased new resources, at up to an almost doubling of customer prices. Load growth had the next largest impact on emissions: a five percent CO2 increase under medium-high load growth, or a four percent CO2 decrease under medium-low load growth.

The next largest impact came from non-firm prices. With lower non-firm prices, the model sold less (decreased output from the existing coal plants), and bought more (purchases carried an adder for gas-fired resources rather than for coal-fired resources). At about the same level of impact is lower costs for renewables, resulting in the model selecting considerably more renewables. Interestingly, the same emissions benefit occurs from either lower cost renewables or lower non-firm market prices.

The last two areas that had a meaningful impact on emissions were the turbine upgrades and the no-DSM case. If the company were to not do the turbine upgrades, it would lower emissions slightly. If the company were to do no DSM, it would raise emissions slightly.

The emission results from RAMPP-3 do not directly compare with the results from RAMPP-4 because of the different approaches in the two planning cycles. RAMPP-3 did not include many of the sensitivity cases that were part of RAMPP-4. However, in both planning cycles, environmental adders had the most impact on emissions, up to 68 percent in RAMPP-3 and up to 80 percent in RAMPP-4. Load growth had the next largest impact in both cycles. The next largest impact in RAMPP-3 seemed to be from altering the level of DSM, whereas in RAMPP-4 it was the non-firm market price. The reasons that the level of non-firm market prices had less effect in RAMPP-3 than they did in RAMPP-4 are not entirely clear. A likely explanation is that RAMPP-3 non-firm market prices started at higher levels than they did in RAMPP-4, and the RAMPP-3 sensitivity cases adjusted non-firm prices by 20 percent rather than 25 percent as in RAMPP-4 .

The emissions reporting mechanism changed between RAMPP-3 and RAMPP-4. In RAMPP-3 the company reported emissions from its own coal fired generation only. The RAMPP-4 methodology reports emissions from all generation sources and deducted emissions that occurred with power production for firm and non-firm sales to other utilities. The RAMPP-4 method was consistent with the reporting method used in the Oregon Department of Energy Climate Change Strategy Study.

Risk Analysis

The electric utility industry is becoming a riskier environment in which to do business. As discussed in Chapter 1, PacifiCorp recognizes that the future will be more risky than the past. Unfortunately, there is no way to avoid some of these risks. They are part of the increasingly competitive environment in which the company must operate. The company is concerned about these increasing risks and is developing methods to evaluate the risk of alternative strategies. Who bears a particular risk is probably less important than that there is risk/reward symmetry. Whichever party benefits from the rewards of a particular strategy should also take on the risks.

Whoever bears cost of risk should reap benefit.

PacifiCorp believes it can keep customer prices low, and is following several strategies to achieve that goal: maintaining existing low-cost generating resources, working to reduce the operating cost of those resources, postponing decisions on new acquisitions while new resource and market prices appear to be declining, and using the wholesale market when it can reduce prices for customers. However, there are uncontrollable elements that could cause prices to increase more than expected. These uncontrollable elements present risks to both the company and its customers.

The following discussion evaluates the lessons about risk derived from the RAMPP-4 results in the following areas:

- Evaluating results on TRC versus on price
- Relying on the wholesale market
- Underbuilding vs overbuilding
- Non-firm market prices
- Gas price increases
- Additional transmission investments
- Load growth
- Significant load loss
- Significant load gain
- Government actions on environmental adders or controls

Evaluating Results on TRC Versus on Price

The company evaluated results of all of the cases on price, and evaluated the TRC results for the cases whose TRC results were inconsistent with their price results (the cases with altered DSM inputs). For all of the cases with the base case level of DSM inputs, the TRC result were consistent with the price results (the percentage change from the base case for TRC was within one percent of the percentage change from the base case for prices). Therefore, for those cases there is no more risk from evaluating on one criteria versus another. The exceptions to this pattern occurred in the cases with altered load growth, the modeling experiment of extension of inputs into the end effect years, or the highest of the adder levels. Risk arising from load growth is addressed below, as is risk from environmental actions by the federal government.

For the cases with altered DSM inputs, the TRC results are quite close to the price results. The following table shows the percentage change from the base case for the DSM cases.

Price and TRC Results for DSM Cases
Table 4-19

	Customer Prices	TRC
Case #11 No DSM	-2.4%	1 .1%
Case #12 20% Reduced DSM Cost	0.0%	0.6%
Case #13 15% Reduced DSM Cost	0.0%	0.5%
Case #14 15% Increased DSM Cost	0.0%	-0.2%

The company did not do Case #11 for any decision making. Therefore the difference between the price and TRC results carries no risk. The difference between the price and TRC results for cases #12, #13, and #14 are too small to carry any significance.

Relying on the Wholesale Market

Relying on the wholesale market for more of the company's resources, rather than owning the resource, is a possible future strategy that could carry more risk. Instead, the company could acquire and own more resources, allowing it to be a bigger player (seller) in the wholesale market. The company could follow the first course -- "go short" and buy on the wholesale market, or it could follow the second course -- "go long" and market the excess. At this point, without a perfect crystal ball, the company does not know which approach would carry more risk. There are risks with either strategy.

The RAMPP-4 analysis used the overbuilding and underbuilding cases as one approach to understanding these risks better. The following section addresses the lessons on risk from those cases. RAMPP-5 will address these issues in more depth.

Underbuilding vs Overbuilding

Underbuilding is a way to maintain flexibility in a time of industry transition. The company chose to specify the underbuilding cases in a way which did not minimize the risks of such an approach. If the price of buying power on the market were to be as high as specified in the underbuilding cases, such a strategy would be risky for customer prices, because customers would be better off only if non-firm market prices were high. If the company could buy power on the market to replace acquiring a firm asset at a lower price, the risk to customers would also be lower.

The riskiness of overbuilding, like underbuilding, depends on the level of non-firm prices. The higher non-firm prices are, the less risk there is with overbuilding. The success of an overbuilding strategy will depend on non-firm market prices during the time period of surplus created by the overbuilding. Although this strategy carries risk, it is a short-term risk that would last only until retail load catches up with the amount of overbuilding.

As PacifiCorp evaluates the alternatives for meeting the needs of customers, it will consider the riskiness of alternatives.

Non-Firm Market Prices

As indicated above, non-firm market price uncertainty presents a risk to retail customer prices. Lower non-firm market prices would lower the amount of revenue the company receives from this activity, reducing the amount of credit applied to the retail revenue requirement. A 25 percent decrease in non-firm prices increased average customer prices by 2.3 percent -- from 42.55 mills/kWh in the base case to 43.39 mills/kWh. A 25 percent increase in non-firm prices decreased average customer prices 2.0 percent -- from 42.55 mills/kWh in the base case to 41.57 mills/kWh.

No overbuild

market power

Unfortunately, this is a risk over which the company has no control. However, the company monitors the market continuously as it makes sales and purchases, and can thereby follow trends as they occur. This gives PacifiCorp more of an advantage than utilities which have less participation in the wholesale market.

Gas Price Increases

Gas price increases present less of a risk than many would assume. In both RAMPP-3 and RAMPP-4, gas prices had little impact on retail customer prices. This is because of their real-world linkage with non-firm market prices. If gas prices are higher, PacifiCorp can compensate for higher production costs out of the new gas-fired plants by selling power (produced at low-cost coal plants whose costs are not increasing) on the wholesale market at higher prices. PacifiCorp's ability to be successful in the wholesale market reduces the retail customer price risk from higher gas prices.

Additional Transmission Investments

PacifiCorp believes that additional transmission investment at this time would be risky for retail customers for two reasons. The first reason is that the RAMPP-4 analyses indicated that it would not reduce total costs for the system. The second reason is that until more of the consequences of FERC's changes in regulating the transmission system are clearer, the company's ability to earn a favorable return on any transmission investments is uncertain.

Load Growth

Load growth had a significant impact on financial results. Under medium-low load growth, average customer prices increased 3.2 percent -- from 42.55 mills/kWh to 43.92 mills/kWh. Under medium-high load growth, average customer prices decreased 2.9 percent -- from 42.55 mills to 41.31 mills/kWh. As in RAMPP-3, the results indicate that the risk of higher customer prices comes not from higher load growth, but instead from lower than expected load growth.

Assuming [illegible] non-firm [illegible] med. non-firm prices.

It is true that from a TRC perspective, the medium-low load growth case had the lowest TRC of any of the 39 cases in RAMPP-4. A low load growth case would have had an even lower TRC. A negative load growth case would have had an even lower TRC again. However, PacifiCorp is not trying to shrink its business. — Need to comment on Load Growth

Significant Load Loss

The loss of significant load from existing customers leaving the system could present a risk to remaining customers' prices. Because of the capital-intensive nature of the plant required to produce electricity, spreading those fixed costs over fewer customers would raise costs per customer. PacifiCorp believes that retaining existing customers through meeting their needs for low cost electric service is essential to minimizing this risk.

required for sweet heart deals for industrials

with MC < AC everywhere
it will always benefit
to grow

Significant Load Gain

The gain of significant load from acquiring new customers could present some risk, but the most likely way PacifiCorp would acquire significant new customer load would be through wholesale sales or retail wheeling. In both cases, the company would have the choice of whether or not to sell to that new customer. In making the decision of whether or not to sell to a new customer, the company would consider the cost of acquiring any new power needed.

Government Actions on Environmental Adders or Controls

The biggest risk in terms of impact on customer prices and on TRC would be government action on environmental adders or controls. The implementation of a major environmental adder such as a significant pollution tax would have the single highest impact on customer prices. In the three environmental cases in RAMPP-4 (discussed above as cases #71, #72, and #73), average customer prices increased from the base case level of 42.55 mills/kWh to 43.74 mills/kWh, 52.84 mills/kWh and 56.16 mills/kWh, respectively. These represent a three percent, 24 percent and 32 percent increase over the base case. These customer price increases did not include the actual cost of the tax; they only included the cost of re-configuring and operating PacifiCorp's system in order to minimize the tax.

Although PacifiCorp cannot control government actions on environmental issues, it can contribute its advice and lessons learned from the trading system on SO2 allowances. The company believes an allowance trading system is superior to a tax. It allows utilities more flexibility in meeting goals, and can bring less price risk for customers.

One reasonable approach to minimize risks is by pushing off decisions until some of the current uncertainty is resolved. In the face of substantial uncertainties, retaining flexibility is a logical general strategy. Maintaining a broad and diversified portfolio will reduce future risk by increasing flexibility. The company aims to follow all technologies and maintain contacts with developers so that it has access to a full range of alternatives for meeting a range of plausible futures. A related strategy is to focus on alternatives with shorter lead times or with flexibility for adjustment in the amount and timing of the resource.

Chapter 5: RAMPP-3 Action Plan Performance

This chapter reviews the consistency of the company's past acquisition activity with its prior RAMPP action plans; it then reviews performance on the RAMPP-3 action plan.

Consistency of Past Acquisitions with RAMPP Action Plans

PacifiCorp has made several major resource acquisitions since it began its integrated resource planning process. Some of those acquisitions occurred "outside" of the RAMPP process in that they had not been specifically named in a RAMPP action plan before acquisition. However, in all cases, a prior RAMPP plan had identified the need for that type of resource, such as peaking, or cogeneration. The company's acquisitions met those needs. For example, the RAMPP action plans did not, and could not, predict in advance a specific peaking contract with another utility. Table 5-1 shows the major acquisitions and their consistency with the preceding RAMPP plans.

Up to the 1990s, PacifiCorp and other utilities acquired almost all new resources from generation it built and owned. These plants had long lead times, which fit well with a two-year cycle for IRP. However, utilities now look to the open marketplace for resources. They must make decisions more quickly because resources on the open marketplace are typically available for a rather limited period of time. The immediacy of decision-making does not fit well with a two-year cycle for IRP. PacifiCorp usually cannot wait until the next RAMPP analysis to decide whether to acquire a resource that is immediately available.

IRP currently occurs in a two-year cycle, making it more valuable for general long-term planning than for immediate decision-making. The actual analysis for each IRP occurs over only a few months of time. During the rest of the two-year period, the company and the public advisory group develop the issues to address in the IRP, prepare and review the inputs, review the model, prepare and review the model outputs, develop and review the action plan, prepare and review the draft report, and prepare and review the final report.

PacifiCorp Resource Acquisitions
Consistency with RAMPP Action Plans

Table 5-1, Page 1 of 2

Decision Date	Resource Acquisition	Resource Size	RAMPP Action Plan in Effect	RAMPP Action Plan Item	Explanation
1992	APS SCCTs	150 MW	RAMPP-2	**Action Item #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. Inititate siting, permitting and procurement.	The Company filed a report with the Arizona Public Service Commission showing that SCCTs were more cost effective than renewable resources to meet this peaking need. The projects are in the siting and permitting stage.
1992	Wind Projects	44 MW	RAMPP-2	**Action Item #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 wind resource agreements were entirely consistent with the action plan item. The wind projects have been modified, but continue toward construction.
1992	SCE Peak Contract	422 MW	RAMPP-2	**Action Item #5:** Initiate siting and permitting for up to 450 MW of SCCTs.	A power purchase proved to be more cost effective than building the SCCTs.
1993	James River	50 MW	RAMPP-2	**Action Item #7:** Sign intent agreements and pursue contract negotiations with industrial customers to achieve up to 300 MWa of cogeneration on line by 1997. Build in options to accelerate or delay construction to allow for load growth uncertainty.	This 50 MW resource is entirely consistent with the action plan item. 45 MW of generation is being installed at Willamette Industries for their own use. Options for future generation have been secured at three industrial sites.

PacifiCorp Resource Acquisitions
Consistency with RAMPP Action Plans

Table 5-1, Page 2 of 2

Decision Date	Resource Acquisition	Resource Size	RAMPP Action Plan in Effect	RAMPP Action Plan Item	Explanation
1993	Hermiston	474 MW	RAMPP-2	**Action Item #7:** Sign intent agreements and pursue contract negotiations with industrial customers to achieve up to 300 MWa of cogeneration on line by 1997. Build in options to accelerate or delay construction to allow for load growth uncertainty. **Action Item #3:** Meet baseload requirements with installation of 500-900 MW of cogeneration and/or combined-cycle combustion turbines (CCCTs) by 2001, consistent with cost-effectiveness criteria.)	Combined, the Hermistion and James River resources are larger than the 300 MWa specified in the action item, but the price was very competitive, and any excess power can be sold in the wholesale market until retail customers need the power. The subsequent RAMPP, RAMPP-3, confirmed the need for the resource to meet retail needs.
1994	WWP Peak	150 MW	RAMPP-3	**Action Item #5:** Meet 150-200 MW of peaking needs by 2001 in addition to the APS SCCTs for a total of 300-500 MW.	A power purchase proved to be more cost effective than alternative ways to meet these 150 MW of peaking needs.

Unless a specific market opportunity occurs during the few months of analysis, the current RAMPP cycle cannot include it; it must wait for the next cycle. However, if the company waits that long, the new resource opportunity will be lost. For this reason, a specific acquisition activity has to occur outside of but parallel to the IRP process. The analysis of the market opportunity occurs within the framework provided by the IRP process.

Table 5-1 describes the company's major resource acquisitions since 1992 and their consistency with RAMPP-2 or RAMPP-3 action plans. They include the acquisition of simple cycle combustion turbines from Arizona Public Service Company for 150 MW of peaking power (consistent with RAMPP-2); two wind projects in Washington and Wyoming to provide 44 MW (consistent with RAMPP-2); a contract with Southern California Edison for 422 MW of peaking power (consistent with RAMPP-2); the James River cogeneration project for 50 MW of gas-fired baseload resource (consistent with RAMPP-2); the Hermiston cogeneration project for 474 MW of gas-fired baseload resource (consistent with RAMPP-2 and recommended in RAMPP-3); and the contract with Washington Water Power for 150 MW of peaking power (consistent with RAMPP-3).

Performance on the RAMPP-3 Action Plan

1) Achieve 40 MWa of cumulative installed cost-effective savings by the end of 1995. By the end of 1997 acquire an additional cumulative 65 MWa of demand-side acquisitions, if cost effective.

Performance: The company modified these goals as a result of RAMPP-3 acknowledgment process. The two-year 40 MWa DSM goal was changed to 17 MWa for 1994 and 30 MWa for 1995. The company achieved 18.5 MWa in 1994, and activity is on track to achieve the 1995 goal. RAMPP-4 establishes new goals for 1996 and 1997.

In 1994 and 1995 the company maintained active programs for the residential market. These included the Super Good Cents program (provides home builders with incentives to construct energy efficient homes), a low income weatherization program (provides energy education, home weatherization services and energy assistance), and residential weatherization loans and grants to qualifying customers. In addition, the company continues to promote installation of energy efficient appliances such as heat pumps (H-PRO), water heater replacement (Hassle Free program), SERP refrigerators, and low-flow showerheads. The company also offered a low income weatherization program through a competitive bid process. As a result an energy services company weatherized over 2,000 homes in Oregon. The company has another competitive bid project in Utah to test an alternative delivery mechanism for DSM acquisition.

Also in 1994 and 1995 the company expanded the availability of the Energy FinAnswer program to broader market segments. In Oregon it now includes commercial retrofit projects in excess of 20,000 square feet, broadened further in 1995 to include all commercial retrofit. In the early 1990's the company developed this innovative financing mechanism to encourage customers to make energy efficiency upgrades for their new commercial buildings. The company provides 100 percent low-interest financing for installation of cost-effective incremental energy efficiency upgrades. The customer pays an Energy Service charge which goes directly on their electric bill. In addition to financing, the program provides other services to customers such as building energy use modeling, project management, and commissioning services.

The following sections provide the RAMPP-3 individual DSM action items and progress on each of those items through mid-1995.

Revise and implement a new Super Good Cents (SGC) program in Oregon, Washington, Idaho, Montana, and Wyoming in 1994. The revised program will tie payments more closely to kWh savings obtained from individual residences.

Progress: Completed. The company revised the tariffs in early 1994 in Oregon, Montana, and Idaho, lowering the incentives to make the programs more cost-effective in these states. In Washington the tariff was suspended in 1994 due to commission staff concerns over program cost-effectiveness.

In Oregon, Idaho and Montana advancements in codes for building shell and general building practices have made incentives for shell measures unnecessary and not cost-effective. The company is dropping shell incentives from residential programs in these states. SGC shell standards in these states have now become a requirement to qualify customers and builders for other energy efficiency supplementary incentives such as high efficient electric water heaters (91 EF rating or above), solar water heaters, passive solar subdivision design, air to air heat exchangers and so on. These changes will contribute to a program spending reduction in 1995 of nearly 40 percent compared to 1994.

The company did not elect to change the program in Wyoming because the program was new just a couple of years ago in that state and there were relatively few participants. The company will not be changing the tariff in 1995, but will review the situation in 1996 to determine if a change is necessary.

Streamline the Super Good Cents program. The program will reflect a more prescriptive design, targeting a 20 percent reduction in administrative overhead costs by 1995.

Progress: Replaced. The company is proposing reducing the amount of the incentives in Oregon, primarily by removing them for shell measures. The reductions lower program costs by more than 20 percent, making the program more cost-effective. The revision to the tariff was effective in February, 1995. Several changes in the program have reduced field labor requirements to support delivery of this program in 1995. Other administrative changes helped reduce cost and made the program more cost-effective. The company improved the tracking database that makes data entry easier, thus reducing costs.

These changes to the Super Good Cents program shift the focus from the builder to the customer. The 1995 advertising and promotional campaign will reflect these changes.

Continue participation in MAP for the states of Oregon, Washington, Idaho, Montana, and California in 1994. Work with BPA and others to renegotiate with manufacturers the incentive payment adjusted for adoption of the new HUD standard expected by October 1994. Participate in renegotiation and implementation of a new regional contract with manufactured home producers and BPA after expiration of existing contract in April of 1996.

Progress: Replaced. The MAP agreement was replaced by a Super Good Cents (SGC) program beginning with homes built after July 1995. PacifiCorp, PGE and BPA funded an advertising campaign promoting SGC. The transition has had minimum effect on penetration levels. An incentive is no longer provided to manufacturers but as of September 1995 approximately 95 percent of all electrically heated manufactured homes built in the region meet the SGC standard.

Continue to work with the MAP collaborative group to improve program cost-effectiveness. Analyze cost-effectiveness of measures which will be included in MAP homes beyond 1994.

Progress: Ongoing. A consultant completed a regional program evaluation for MAP in mid-1994. The study indicated that savings were lower than expected; this adversely impacted the program cost-effectiveness. The transition of MAP to SCG has improved the program cost effectiveness.

Participate in a collaborative study of residential code compliance in Oregon. The study will provide information on improving compliance and enforcement of the residential energy code in Oregon. The study will be completed in 1994.

Progress: Completed.

Participate and be knowledgeable about code development issues in Wyoming, Idaho, and Utah. Facilitate where possible adoption of an MCS equivalent code.

Progress: Ongoing. No code development issues have moved forward in Wyoming or Utah. A residential code upgrade occurred in Idaho that will be in effect as of January 1, 1996, which improves energy efficiency requirements but does not meet the model conservation standards.

Operate a residential retrofit program in Washington and California in 1994 and 1995. Make revisions to weatherization program delivery to improve cost-effectiveness.

Progress: Ongoing. The Home Comfort program is a residential retrofit program offered by the company to qualifying Washington and California customers. The company exceeded the California program goals. Program delivery was changed to offer a more standardized weatherization offer in Washington. The Washington goals will likely be completed ahead of schedule. The program will be evaluated in 1995.

Market test alternative financial assistance options such as third party finance, rebates, and the energy service charge.

Progress: Completed. See above response.

Test other delivery mechanisms which would improve program cost-effectiveness. Launch a customer response oriented program in Oregon as an alternative to a community based "Pacific as general contractor" approach.

Progress: Completed. The Super Good Cents home Improvement Program tested three audit delivery mechanisms: 1) a self-audit, 2) a standard weatherization audit, and 3) a comprehensive Home Comfort audit. The self-audit was the preferred program and was implemented in late 1993.

Continue availability of company weatherization programs which are required by state statutes.

Progress: Ongoing. Activity for weatherization programs in Oregon increased in 1994 with the addition of rebates for supplemental measures. The company refiled Oregon cost-effective numbers in November 1994. Over 80 percent of the weatherization activity has been with the Oregon 25 percent Rebate program. The balance of activity was in the Zero or Low Interest Loan program.

The company is currently reviewing alternative weatherization approaches and will design one standardized offer and audit process. This will improve program delivery and overall cost-effectiveness. The company is also investigating third party financing. The goals are to lower administrative expenses and capital requirements. The company plans to file revised tariffs by fourth quarter 1995.

Operate a direct install water heating retrofit program targeted at multi-family residences in Utah during 1994. Conduct prototype test of measures to assure measures perform as deemed in Utah during the second quarter of 1994.

Progress: Completed. ECON, an energy services company, treated over 10,000 multi-family units in Utah during 1994. A test of savings in the second quarter of 1994 confirmed that savings were as projected and that earlier concerns about savings used erroneous consumption figures. The company plans to evaluate the completed program in 1995.

Operate a competitive bid, Pay-For-Performance low income program in Oregon to test as an alternative delivery system.

Progress: Completed. ECONs received the bid in early 1994 and treated over 2,251 low income homes in 1994 and 797 homes in 1995. Pay-for-performance computations will begin in the second quarter of 1995.

Continue to offer low income weatherization programs and provide evaluations to regulatory agencies to demonstrate that low income programs are being assessed and action taken to improve program cost-effectiveness. In Washington use a standardized audit and provide payments based on measure cost-effectiveness. Continue to offer energy education to participants. In Oregon provide a study to quantify benefits of energy education and arrearage impacts of the low income program.

Progress: Ongoing. The 1994 Oregon Low Income program evaluation was well-received by the OPUC staff. Standardized audits will be in place in Oregon and Washington by year end 1995. Energy education continues to be part of the Washington program. The company is developing a program evaluation for the system-wide low income programs. It will include assessments of savings from energy education and reductions in billing arrearages.

Develop educational and informational literature to support improved information on home energy usage through brochures providing energy efficiency tips, packets providing guidance in performing a home energy audit, and brochures providing appliance purchase information.

Progress: Completed. The Home energy Savings Center information series was completed in May, 1994. The center has four instructional how-to guides and twelve informational brochures. The topics covered in the how-to guides include:

- How-To Improve Your Home's Heating and Cooling
- How-To Manage Your Home's Energy Bill
- How-To Assess Your Home's Energy Usage
- How-To Maintain Your Home's Energy Safety.

The informational brochures covered:

- Home Heating Choices
- Home Cooling Choices
- New Home Building Techniques.

A complete set of the Home Energy Savings series is available at any PacifiCorp office.

In 1994 the company also produced a customer communications campaign to help foster customer interest and involvement in home energy efficiency through the free materials. The campaign, with its newspaper and television components, aired in selected markets in the company's seven state service territory in the summer and fall.

Market test energy information displays in Oregon. Determine the value of providing energy efficiency information which influences customer energy use decisions.

Progress: Ongoing. A broad market transformation study in 1995 will include this testing.

Conduct a customer energy survey (Energy Decisions) in 1994 to collect demographic, equipment, housing and attitudes data. The data will be analyzed to assess resource potential and assist in program design. Complete residential survey and assessment in 1994 and commercial survey and assessment in 1995.

Progress: Completed. The company administered the 1994 Energy Decisions Residential energy use survey. The data are being complied, analyzed, and will soon be available to assess resource potential and assist in program design.

Rely on improved standards as the preferred way to achieve appliance energy savings. Participate in collaborative efforts with other utilities through organizations such as the Western Utilities Consortium and others to improve the efficiency of new appliances.

Progress: Ongoing. The company joined 34 other organizations in the Consortium for Energy Efficiency (CEE) in 1994. This national collaborative will target national manufacturers to raise the energy efficiency standards for equipment they manufacture and market.

The Western Utilities Consortium (WUC) is working as a sub-committee to the CEE. The WUC launched the compact fluorescent lamp initiative in December 1994. The company is currently evaluating it for the PacifiCorp service area. The programs currently being considered for national collaboration are Compact Fluorescent, Horizontal Axis Washers, Heat Pumps/Air Conditioners, and Commercial HVAC.

Participate in collaboratives to adopt standards for technologies such as compact fluorescent lamps, horizontal axis washers and other new technologies. Investigate possible technologies such as micro wave dryers as a cost-effective alternative.

Progress: Ongoing. See the progress report for the previous action item.

Maintain board membership in the Super Efficient Refrigerator Project. Oversee implementation of the 1994 new model design and begin promotion of the refrigerators.

Progress: Ongoing. A company representative serves as a director on the SERP board and attends annual meetings dealing with policy issues. The SERP refrigerators began to appear in appliance showrooms and accompanying informational brochures in April 1994. An even more efficient model began appearing on showroom floors in mid-1995.

Continue to participate in BPA's Blue Clue program or a similar initiative, encouraging the purchase of energy efficient appliances. In addition, develop home tuning and home maintenance tips for energy efficient performance. Extend Blue Clue or a similar informational initiative to Utah and Wyoming.

Progress: Replaced. The Bonneville Power Administration's Blue Clue program was discontinued due to reduced funding, eliminated SGC refrigerator rebate, and a revised informational program with no MWh savings attributed to the activity.

The company replaced the BPA Blue Clue program with educational services which provide energy efficiency information through the Energy Services Hotline (a 24-hour service available to customers) and with Home Energy Savings Centers in local company offices which provide a broad array of brochures on energy efficiency.

The company continues to be active through other energy efficient appliance ventures such as the Hassle Free Water Heater replacement program, the Super Efficient Refrigerator Program (SERP), the Water heater Heat Pump pilot program for MAP homes, and through participation on the Northwest Regional Energy Efficiency Appliance and Lighting group (NWREAL).

Conduct follow-up survey and verification of Oregon showerhead saturation program to determine applicability to other jurisdictions.

Progress: Completed. The company re-designed the survey to incorporate questions regarding free-ridership and lessons learned from the original survey. The company began administering the survey in December, 1994. It is completed and the report should be out by mid-1995.

Offer a saturation showerhead program for customers currently on schedule 5 in the State of Utah.

Progress: Completed. In the second quarter of 1994 the company sent a home analysis survey to 6,538 Utah households currently billed on schedule 5. Respondents received a "Water Smart" kit that included a low flow showerhead. Over 2,600 customers, or approximately 40 percent, completed and returned the survey.

Re-assess the cost-effectiveness of radio communication direct control of electric water heaters as allowed under schedule 5.

Progress: Ongoing. This project has proceeded to discussions with vendors. The company is studying costs associated with putting 5,000 water heaters under direct utility control through VHF radio using frequencies already licensed by PacifiCorp. Each water heater usually cuts 0.75 to 1.0 kW off peak load. At 0.75 kW per water heater, the system would deliver 3,750 kW of dispatchable peak load at an average cost of $260 per kW.

The next step is to identify key areas where this water heater load control could defer local transmission and/or distribution upgrades. Pending administrative details, a pilot of water heater load control could begin in 1996.

Continue installation of energy efficient water heaters (.93 or equivalent) through the Hassle Free Water Heater Guarantee Program. Target installation of up to 3,500 tanks per year over the two year action plan. Encourage the installation of low flow showerhead, aerators, and pipe wrap, along with energy efficient tanks where applicable.

Progress: Ongoing. The company continues to install energy efficient water heaters under the Hassle Free water heater repair and replacement program. The company replaced a total of 3,828 water heaters under the program in 1994; 70 percent met the energy efficiency guidelines of the program.

Pilot a water heater load control program starting in 1994 in Oregon as part of the company's automated distribution project.

Progress: Ongoing. The vendor has decided to stop production of the only water heater load control device that works with the automated distribution system being piloted in Portland. The company is talking with two other vendors about licensing and producing the device in 1996.

Implement a comprehensive commercial retrofit program for buildings over 20,000 square feet in the State of Oregon in 1993. Design the program to provide flexibility in addressing customer needs which could include items such as controls, lighting only, and building operation & maintenance training. Establish building operating savings standards to guide building managers in efficient operation of their buildings.

Progress: Completed in late 1993.

Evaluate commercial retrofit program results in Oregon for 1994. Recommend program revisions and assess feasibility for expansion to other jurisdictions in 1995.

Progress: The company completed the commercial retrofit program evaluation in Oregon. The evaluation indicated the company should offer more design assistance and improve to the wording of contracts and letter of intent documents. This program is ready for expansion to other states when the need arises.

Operate task team in 1994 to develop a small prescriptive commercial retrofit program for buildings under 20,000 square feet. Assess feasibility of implementation before year end 1994 in Oregon. .

Progress: Completed. The company completed the program feasibility assessment and launched the program in the first quarter of 1995. The program offers customer incentive efficiency improvements in lighting, programmable thermostats, air conditioning and heat pump installations.

Operate the EPA Green Lights program for company facilities. Complete development of site inventory, environmental assessment, energy efficiency audit and prioritization by 1994 and begin installations in 1995 to be completed within five years.

Progress: Ongoing. The company completed procedures regarding site inventory, environmental assessment, audits and amortization on schedule in 1994. A pilot program to test delivery was successful in 1994. Completion of the program is scheduled for 1996 through 1998.

Develop a comprehensive catalog of energy efficiency products available for commercial application. Distribute catalog to company field personnel by year-end 1994.

Progress: Completed. Under a PacifiCorp contract, Iris Communications of Eugene, Oregon, developed and produced the first Commercial Products Energy Source Catalog. PacifiCorp distributed 100 copies of the catalog to local offices and to selected trade allies.

Continue supporting the development of REMPRO program through the Everett and Portland Community College campuses as a tool to provide effective energy efficiency operation and maintenance building training for building managers.

Progress: Completed. The company developed and implemented this program in Portland two courses: "Cooling Tower Fundamentals" and "Energy and Water Accounting." However, customer participation was low. The company will continue to support REMPRO initiatives in 1995, but is examining the nature of that support to maximize the benefits.

Participate in code development and implementation design for new commercial codes in Oregon and Washington. Participate in a collaborative effort to establish training and educational programs for commercial energy code compliance in Washington.

Progress: Ongoing. The new Washington Commercial codes are in effect; training and education programs are underway. Training and education, which began in 1994, will last for three years. The new Oregon Commercial code should be effective by April 1, 1996. The training and education effort begins in early 1995 and will continue for two years.

Conduct a detailed study to determine the impact of building code changes on energy efficiency in new commercial construction. Complete a report which includes recommendations for changes to the Washington Energy FinAnswer Program in 1994 and the Oregon program in 1995.

Progress: Ongoing. The company completed the Washington analysis in mid-1994 and reviewed it with the Commission staff. The company plans to complete and review the Oregon analysis with commission staff by year end.

Conduct a common practice survey for new commercial construction in areas of the service area not currently covered by research studies.

Progress: Discontinued. The common practice study was originally proposed to establish a baseline compared to the energy building code. The company determined that some measures were beyond code. These tended to offset installations which didn't quite meet code. The company is assuming the baseline usage to be code unless the customer plans indicate that they were planning to install more efficient equipment or measures than code required. Once this was decided, the common practice study became unnecessary for establishing the baseline building usage.

Improve program cost-effectiveness through streamlining. Reduce administrative costs, change funding criteria, and improve program design. Reduce process steps in the commissioning (including inspection and performance testing) phase.

Progress: Completed. The company streamlined its new commercial construction programs in many ways during 1994. All programs except for irrigation have been combined into one process; this will save on administrative costs. A computerized spreadsheet reduces the amount of paperwork required for the Energy FinAnswer 12,000 program by replacing several specialized spreadsheet models. The resulting efficiencies reduced program administrative costs at both the staff and field level. The company continues to look for opportunities to improve and streamline the program in 1995. Part of this effort involves combining all Energy FinAnswer programs for commercial and industrial customers into one program for ease of administration and delivery.

Using an outside consultant's study, the company was able to more accurately estimate the level of funding. The company also reduced the supplemental funding to one times the resource amount. In addition, the company increased the number of measures which can be recommended through prescriptive approaches rather than requiring extensive energy use modeling. The overall effect has been a reduction in costs required for consultants to perform energy use modeling. Commissioning costs cover only the most sophisticated energy efficiency measures. Owners must perform most of the basic inspections.

Improve leverage of trade ally networks (architects, design firms, etc.) through enhanced training and informational materials. Complete a pilot building design study to influence architects to consider passive design features which will lower energy usage.

Progress: Ongoing. The company has provided analyses to specific customers and their design teams which assist in specifying energy efficient equipment. In a special 1994 pilot program, energy efficient information was provided to national commercial accounts, lodging and restaurant customers. Prior knowledge of commercial building practices indicates that passive design features are not compatible with commercial building design and construction criteria.

The company initiated a lighting retrofit trade ally program in Oregon for 1995. The program provides training to trade allies, lead generation, and joint sales calls by trade ally representatives and company account managers.

Complete study to verify savings and determine appropriate calibration of modeling tools for new construction energy savings estimates.

Progress: Completed. The company completed this study in 1994, and is now calibrating the modeling tools.

In 1994 participate in a collaborative (LBL & BPA) study to quantify energy benefits of the commissioning process.

Progress: Completed.

Offer to commercial customers the Energy FinAnswer program, designed to improve new commercial building energy efficiency, in all jurisdictions served by the company. Achieve the following penetration rates in new commercial construction:

RAMPP-3 Goals for Energy FinAnswer
Table 5-2

	Large Buildings (over 12,000 sq ft)		Small Buildings (less than 12,000 sq ft)	
	1994	1995	1994	1995
Oregon	67%	70%	40%	45%
Washington	45%	65%	20%	30%
Idaho	45%	65%	20%	30%
Montana	35%	45%	35%	40%
California	45%	65%	35%	40%
Wyoming	35%	45%	35%	40%
Utah	67%	70%	20%	30%

Progress: Completed. The company estimated the market potential for new commercial buildings constructed in 1994 from the F. W. Dodge database, a major source of information about newly constructed commercial square footage. The 1994 commercial projects use the date construction started. The penetration rates by state are as follows:

Performance on RAMPP-3 Goals for Energy FinAnswer
Table 5-3

	1994 Target	1994 Actual(1)	1994 Target	1994 Actual (1)
Oregon	67%	101%	40%	101%
Washington	45%	28%	20%	28%
Idaho	45%	-	20%	-
Montana	35%	11%	35%	11%
California	45%	144%	35%	144%
Wyoming	35%	35%	35%	35%
Utah	67%	25%	20%	25%

(1) Actual penetration rate is combined small and large commercial buildings.

Influence the adoption of commissioning standards through participation in a National Building Commissioning Association. Provide funding to ASHRAE for commissioning guidelines group to establish protocols for incorporation into building code practices.

Progress: Ongoing. A draft of the ASHRAE Commissioning Guidelines was available for public review in June 1994. ASHRAE is concerned about specifying functional performance test requirements, even though they are already the primary reference for equipment installation standards. The company sent two participants to the National Commissioning Conference in May 1994. The company is involved in editing previous conference papers on commissioning for inclusion in a book the American Council for an Energy Efficient Economy (ACEEE) is preparing.

Establish protocols for commissioning Path B (defined as non-ESC participant, but installs recommended measures) program participants in 1994.

Progress: Completed. The Path B protocols have been established as follows:

- Commissioning is undertaken at the owner's option;
- If undertaken, the process is identical to that for a project in which the company is financing -- PacifiCorp supervises and pays for the commissioning;
- If not undertaken, savings estimates for commissionable ECMs are derated by 25 percent. (This derating factor is consistent with the findings of the LBL study.)

Offer the Energy FinAnswer program to industrial customers in Oregon, Washington, California, and Utah. Expand the program to Idaho in 1994. Develop a feasibility assessment for expansion of the program to Montana and Wyoming during 1995.

Progress: Ongoing. The Energy FinAnswer program was tariffed for industrial customers in Montana in the fourth quarter of 1994. The company offers an Industrial Major Account program in Utah, Wyoming and southeastern Idaho. The northern Idaho properties were sold to Washington Water Power effective January 1, 1995.

Continue development of an industrial customer database which provides information to improve assessments of resource availability and cost. Create major account plans for the top 100 customers, assessing opportunity and cost of resource acquisition.

Progress: Ongoing. The company conducted a survey of existing industrial data sources which existed within the company in 1994. Staff are now reviewing the data integrity of one of the large industrial databases. This project will continue in 1995 with expected completion by year-end.

Participate in collaborative effort with NPPC and others to complete Original Equipment Manufacturers (OEM) study. The study will examine motor drive applications and how to influence efficiency improvements in this equipment category.

Progress: Ongoing. In November of 1993, PacifiCorp provided support to a national collaborative study by Easton Consultants. Other sponsors included USDOE, BPA, Portland General Electric, Northwest Power Planning Council, Idaho Power, BC Hydro, and others. This project is nearly complete. The July 1994 draft study "Strategies to Promote Energy Efficient Motor Systems in North America's OEM Markets" identified the three best OEM target areas for promoting energy efficient motors: air compressor systems, HVAC water pump systems and industrial fans and blowers. USDOE proposed an extension of the study to include a fourth area -- motors for process fluids pumping in the petroleum refining, pulp & paper, and chemical industries. This extension will delayed the final report until the end of March 1995.

Add additional program options to address prescriptive path measures in industrial facilities. Consider the following measures as possible candidates for prescriptive path for motors and lights.

Progress: Ongoing. The company is using commercial software for the industrial program. This avoids duplication of effort and eliminates the need to incur additional development costs.

Operate commercial and industrial Pay-For-Performance contracts in Utah in 1994 as a comparison on cost-effectiveness of alternative delivery systems.

Progress: Completed. The company has contracts with Onsite and CES/Way in Utah to offer commercial and industrial energy efficiency to Utah customers; they pursued contracts with customers throughout the year. Completion of the commercial contract should occur in the third quarter of 1995. The industrial contract should result in substantial installations in 1995.

Improve cost-effectiveness of Irrigation FinAnswer in California in 1994. Examine alternative designs such as a prescriptive approach versus a custom approach.

Progress: Completed. 1994 saw significant improvements in the California Irrigation FinAnswer program. An evaluation of grower education with irrigation System Analysis showed significant energy savings. The US Bureau of Reclamation customers are now in the program. The company has made two improvements in the cost-effectiveness of the program. First, reductions in audit and management costs through a new audit procedure screen out customers with low savings potential early in the process, automate the audit process and streamline credit approval for small projects. Second, the company increased the program penetration rate through more aggressive follow-up with Path B projects and improved the quality and focus of the customer reports.

Study Irrigation options for customers in Idaho in 1994.

Progress: Ongoing. The company extensively studied the options for irrigation customers in Idaho and found that there was not a cost-effective DSM opportunity which would justify design and development of a loan or rebate program. An overall strategy for the irrigation sector is currently under development.

Continue the ditch improvement program.

Progress: Discontinued. The company explored many different financing options with the Farmers Irrigation District in Hood River. The program was put on hold pending the resolution of two issues: 1) the amount of the energy and water savings attributable to the company in a cooperative effort, and 2) since the water saved through ditch improvements remains in the streams, there is no benefit to growers or irrigation districts. Some fear they may lose water rights. This is a disincentive to convert to pipe. Farmers Irrigation District is unique in that it has control of water released from storage and also has generation revenue benefits from saved water. At this time the company is no longer pursuing opportunities in this area.

Continue to offer the radio communication direct load control for irrigation pumps in Idaho and Utah. Test the system and seek more participants if cost-effective.

Progress: Ongoing. Since 1991 the company has spent over $780,000 to make the irrigation load control program in Idaho and Utah fully operational. During 1994 the company installed or replaced radio control units on approximately 500 pumps. This brings 4,278, or 97 percent of the pumps in the area into controllable status. During 1995 the company plans to either replace or install another 500 radio control units.

Evaluate pay for performance agreements with contractors. Assess this method for cost-effective DSM acquisition. Evaluate competitive bid process and make recommendations on how to improve the process.

Progress: Ongoing. Implementation of the ECON contract and verification of savings from the pilot test in Utah and from one complex in Washington appear to support the cost-effectiveness of this DSM acquisition method. The company's 1994 RFP document, which was approved by the WUTC on November 23, 1994, include these improvements. The evaluation of the ECONs multi-family showerhead direct install program is in progress and expected to be completed in the first quarter of 1996. Draft data should be available in December 1996.

Continue participation in Evaluation Advisory Groups to obtain external review and input into improvement of program evaluations and process. (NW Evaluation Group, Utah Evaluation Collaborative, and Regional Evaluation Network).

Progress: Ongoing. The company has been meeting regularly with the NW Evaluation group, the Utah Evaluation Collaborative, and attending and participating in the Regional Evaluation Network meetings. These groups review and help improve draft evaluation plans and reports.

Develop a comprehensive verification plan for determining accuracy of savings estimates which balances costs of verification with the commensurate risk and size of the project. Collaborate with state agencies to receive input on development of the verification plan.

Progress: Ongoing. The company has been meeting regularly with the Northwest Evaluation Advisory group to get input on the development of a comprehensive verification plan for determining accuracy of savings estimates. Evaluation plans and a work plan have been developed that streamline efforts and employ economics across the program evaluation.

Conduct program process and impact evaluations to improve cost-effectiveness.

Progress: Ongoing. By January 1995, the company completed most of the impact evaluations identified in 1994. At this time, the regulatory need for formal process evaluations is uncertain. On an ongoing basis the company assesses program delivery and administrative activities for potential improvements. In 1995 the company plans to evaluate all DSM programs.

Conduct a free drivership/market transformation study for residential and commercial new construction and appliance improvements.

Progress: Ongoing. The company is conducting a broad electric energy efficiency market impact study in 1995 (i.e. "Market Transformation") to estimate the company's contribution to improvement in electric energy efficiency. All program evaluation that was ongoing or planned to be started in the next quarter includes efforts to quantify these effects.

Design, implement, and report on an automated meter reading, real time usage display, time of day pricing, and direct load control pilot project in conjunction with the automated distribution project in 1994/95.

Progress: Ongoing. The automated distribution pilot project is underway. All functions passed the mini-test in September 1994. Six prototype units of the In-home Energy Monitor were delivered to PacifiCorp in November of 1994. Four units were programmed and installed in Portland, Oregon, customer homes in November. The fifth unit suffered damage by the vendor during modifications. It was repaired and installed in December 1994.

The company was unable to perform the direct load control test because the devices are no longer available from the manufacturer. The device may become available from a new manufacturer in 1995.

The company offered the Time of Day tariff to 200 customers in Cannon Beach under Oregon Schedule 6. Fourteen accepted. The first evaluation report should be completed by third quarter 1995.

Study and report on the potential for a pilot experiment on local transmission and distribution deferral using DSM to reduce need for system upgrades to meet peak requirements on a localized level.

Progress: Ongoing. The company had two goals for the project. 1) incorporate DSM and Customer Load Management (CLM) as a strategy for transmission and distribution deferral; and 2) conduct a pilot to demonstrate the effectiveness of DSM/CLM technologies for deferring T&D capital expenditures.

The company's Engineering department completed two transmission five-year studies that included an assessment of opportunities for DSM/CLM to offset the need for feeder, substation, and transmission upgrades. The company is performing five-year studies for the following areas: Grants Pass, Yreka/Mt. Shasta study, and the Yakima Valley. The studies will assess the customer load and potential for DSM/CLM strategies.

Three analysis tools are being developed for the DSM/CLM analysis. The first is a DSM/CLM technologies matrix to summarize important characteristics of DSM/CLM technologies and pricing strategies. The second is a procedure for determining local area avoided costs. The third is an assessment of costs and benefits from high saturation programs used by other utilities to implement local area DSM/CLM and pricing.

2) Continue with actions necessary to have 200 MWa of renewable resources on line by 2001, if cost effective.

a) Bring the SW Washington and Foote Creek, Wyoming, wind projects on-line by 1996. The company's share of the output will be 56 MW (19 MWa). PacifiCorp assumed half of the share released by Idaho Power in addition to its previous commitment. The consortium of project developers in the Wyoming project, including PacifiCorp, is also selling 25 MW to the Bonneville Power Administration (BPA). Kenetech Windpower will construct the wind plant.

Performance: In late September, 1995, BPA signed a letter of agreement to purchase a portion of the power generated at the Foote Creek facility.

The 68.1 MW project is now awaiting the Bureau of Land Management's Record of Decision, following the 30-day comment period on the final environmental impact statement. A positive decision would allow construction to commence, with the facility operating by late 1996. Other owners include Eugene Water and Electric Board, Tri-State G&T and Public Service Company of Colorado.

At about the same time, PacifiCorp also reached agreement with Kenetech Windpower Inc. and Portland General Electric to build a 31.2 MW wind project in the Columbia Hills near Goldendale, Washington.

Both agreements clear significant hurdles in siting and building commercial-sized renewable wind resources. With both projects, PacifiCorp will be the majority owner and Kenetech will be the developer. The Foote Creek project will have 195 wind turbines atop tubular steel towers; the Columbia Hills project will have 85 of the same type of turbines.

b) During 1996 and 1997, evaluate the cost-effectiveness and performance of the southwest Washington and Wyoming wind projects, and determine through continuing communication with wind developers the cost-effectiveness and performance of other wind projects in North America.

Performance: These evaluations cannot take place until the wind projects are on-line.

c) If these early projects confirm the cost-effectiveness of wind, pursue agreements in 1996 and 1997 with wind developers for an additional 40-50 MW of wind resources to be on-line by 1999. PacifiCorp has an option to purchase additional wind plant from Kenetech at the SW Washington site.

Performance: PacifiCorp continues to talk to wind developers about additional projects that could meet current cost-effectiveness standards.

d) Consistent with cost-effectiveness criteria, pursue agreements with developers to have 50-100 MW of geothermal resources on-line by 1998.

Performance: PacifiCorp is continuing discussions with geothermal developers to find projects that meet current cost-effectiveness standards.

e) Continue to participate in the Solar II demonstration project to determine the cost effectiveness and performance of utility-scale solar energy.

Performance: PacifiCorp continues to support and participate in the Solar II demonstration project. Start-up should be in 1995. During the three-year demonstration period, the plant will undergo rigorous testing and evaluation to assess the performance of this technology.

The Solar II project will not operate in the long term for power production after its demonstration run. The duration of this run depends on funds available, but the current plan calls for one year of operation in a test and evaluation mode, followed by two additional years of straight production experience.

Since its inception, the project goals have been demonstrating and testing the integration of solar thermal components of central station solar thermal generation with molten salt storage. The 10 MW size of the plant provides a reasonable technical basis for engineering scale-up to true commercial scale for this technology (100 MW or greater), based on the operating experience it provides. At this 10 MW size, however, economical operation for power production is not cost competitive with wholesale markets and conventional resources, even considering only variable costs.

The possibility exists that the facility can be used to continue to test emerging solar thermal enhancements such as gas hybrid options, but no commitments have been made at this time. Such future use would depend on federal funds and U.S. Department of Energy agreement, since DOE has title to most of the physical property.

f) Continue to participate in the Dangling Rope Marina photovoltaic project in Utah. The company will help install photovoltaic equipment to reduce the marina's need for diesel fuel to power its equipment.

Performance: The Dangling Rope photovoltaic project has now received funding approval from the U. S. Department of Energy, the National Park Service, and the Utah Office of Energy and Planning, in addition to PacifiCorp's support. Major equipment procurement and construction will occur in 1995. PacifiCorp has participated in reviews of the project design and equipment specification, and will continue to monitor the technical and commercial progress of the 100 kw photovoltaic installation.

g) By mid-1994, finish installing photovoltaic equipment on three buildings in PacifiCorp's service territory to better understand the operation and economics of direct generation from smaller dispersed photovoltaic units.

Performance: PacifiCorp installed three systems of photovoltaic generation equipment in three states in its service area. All are now producing electricity. The company installed the first at the its district office and service center in Moab, Utah in December, 1993. Its rating is 5 kW peak output; it consists of 20 panel units and associated controls and inverter equipment installed. The company installed the same kind of system at Wilson Elementary School in Green River, Wyoming, in April 1994. The third system, with a rated output of 5.7 kW, began generating power in December 1994 for the administration building of the High Desert Museum south of Bend, Oregon. Each project presented specific siting, installation and operating challenges. A modem connection at each installation provides data on hourly energy output. Preliminary findings show the systems are producing energy at levels near their rated capacity. After all of the systems have been operating a year, the company will prepare a performance analysis and distribute it to interested parties.

h) Identify targeted geographic areas with constrained transmission and distribution capacities. Evaluate general and specific opportunities to use direct load control and distributed generation technologies as a cost-effective means to resolve constraints.

Performance: PacifiCorp's transmission and distribution (T&D) planning group reviews proposed upgrades of feeders, substations and transmission lines to identify sites where DSM and Customer Load Management (CLM) could reduce the need for such upgrades. The DSM policy and strategy group then analyzes these sites to determine the potential for DSM and CLM measures.

The group has completed this analysis for Oregon and is extending it to Washington, Idaho, Montana and California. The company will then expand the planning and customer identification process to Wyoming and Utah. The T&D planning group will propose DSM and CLM programs (including direct load control) where they will be most cost effective, and recommend sites for pilot tests.

Southeastern Idaho has constrained transmission and distribution capabilities. The company targeted it several years ago with an irrigation load control program. Since 1991, the company has made a concerted effort to make that irrigation load control program fully operational. In 1994 the company either installed or replaced radio control units on about 500 pumps. This made 97 percent of the 4,433 pumps in the area controllable. In 1995 the company has been replacing or installing radio control units on the remaining pumps in the area.

PacifiCorp also identified Yakima, Washington, as an area that could defer a major transmission upgrade if sufficient DSM or CLM could reduce the growth rate in peak power needs. The company evaluated a group of technologies, focusing on two: fuel cells and stand-by generators (both customer-owned and utility-owned). Both technologies are still too expensive for wide spread use, but the company continues to monitor the cost and performance data. The value to the local area of avoiding a transmission upgrade for several years may justify the cost of pilot testing either the fuel cells or the stand-by generation.

i) Determine any unique considerations associated with various levels of renewable resources for integrating them into the company's system.

Performance: It is impossible to plan when the wind will blow. For this reason, for planning purposes, the company has de-rated the wind capacity that qualifies as reserves to 90 percent of expected average generation each season. Wind resources also do not lend themselves to the usual pre-schedule procedure for scheduling resources. For example, delivery of output from the Foote Creek wind project in Wyoming to BPA will be after a 168 hour time lag. This will require that the company store the energy in its west-side hydro system until delivery time. PacifiCorp continues to evaluate the technical considerations for allocating the right amount of wind output to reserves. PacifiCorp has been working with the OSU Wind Research Cooperative since 1991 when it began. The Company's contributions run at $16,000/year.

Integrating geothermal plants into the operating system is easier than wind. The company has encountered few problems in integrating output from the Blundell plant in Utah.

PacifiCorp will be able to evaluate the integration of photovoltaic (PV) resources into the local grid through the three sites that have PV panels. PacifiCorp is in the second year of funding for the Northwest Regional Solar Monitoring Network. The Company's contributions are about $12,000/year plus access to the data generated by three company-installed solar monitoring sites.

3) Meet baseload requirements with installation of 500-900 MW of cogeneration and/or combined-cycle combustion turbines (CCCTs) by 2001, consistent with cost-effectiveness criteria.

a) Proceed with the Hermiston project according to the terms of the agreements.

Performance: The Hermiston project is under construction. PacifiCorp expects it to come on-line in 1996.

b) Continue to evaluate cogeneration options with industrial customers in both the Utah and Pacific divisions. Reach agreements to develop projects or to secure options where cost-effective.

Performance: Cogeneration opportunities with several industrial customers are currently being evaluated. The customers range from a consortium of small manufacturers in Oregon to a large multi-product industrial complex in Utah. In addition, several customers in the oil and gas industry in Wyoming have approached PacifiCorp to evaluate their cogeneration potential.

c) Continue to evaluate cogeneration and CCCTs with independent developers. Reach agreements to develop projects or to secure options where cost effective.

Performance: Independent developers continue to offer both cogeneration and stand-alone combined cycle units to PacifiCorp. Some of these offers include an option for equity participation; others would provide purchased power only. Most of the offers involve projects in the Pacific Northwest, though they extend as far east as Colorado. Some of the offers are more attractive than others in comparison to other market options, and the company continues to monitor them closely.

4) Evaluate clean coal technologies such as gasification, and evaluate the feasibility of potential sites for new coal resources.

Performance: PacifiCorp conducted a special study of clean coal technologies in 1994. The RAMPP Public Advisory Group heard a presentation on that study at the December 1994 meeting, and its results were incorporated into RAMPP-4.

5) Meet 150-200 MW of peaking needs by 2001 in addition to the APS SCCTs (see item a), for a total of 300-350 MW. Operational and resource uncertainties may require the company to acquire more peaking resources sooner.

a) Complete construction of 150 MW of SCCTs in Arizona Public Service Company's service area to be on-line by the end of 1996.

Performance: Due to the changing power markets, the company has slipped the projected on-line date for the APS CTs to late 1998. PacifiCorp will reassess this timeframe in 1996.

b) Identify at least two pumped storage sites and determine their feasibility and cost. If these projects are cost-effective, proceed with obtaining siting permits and equipment in 1996 and 1997.

Performance: PacifiCorp has worked with developers to identify three pumped storage sites. One is near the Great Salt Lake and two are near Sigurd in southern Utah. RAMPP-4 shows the system will need new year-round capacity resources in 2003. Lead time for the pumped storage sites is four years. PacifiCorp can therefore postpone a decision on whether to proceed until 1999.

c) Identify potential sites for up to 300 MW of SCCTs. If these projects are cost-effective, proceed with obtaining siting permits and equipment during 1995 to 1997.

Performance: PacifiCorp has completed a siting study of potential SCCT sites and prepared a rank-order preference of the sites. The study heavily weighted gas pipeline and transmission access, as well as several other factors that can affect costs. Purchased power is now a more cost effective choice to meet peaking needs. However, if SCCTs are cost-effective when the company needs to make a siting decision for new peaking resources, the results of this siting study will be available.

d) Pursue opportunities to purchase power that provides peaking benefits and are more cost-effective than building or acquiring peaking resources.

Performance: In 1994, PacifiCorp entered into two agreements with Washington Water Power. One was a purchase of 150 MW of summer-only capacity. The other is an exchange of 50 MW of summer/winter capacity. The agreements exemplify the strategy of pursuing purchased power when it is more cost effective than building or acquiring peaking resources.

e) Analyze the relative value of alternative peaking resources. The RAMPP research provides initial insights into peaking resource requirements. The company will apply detailed system simulation tools to specify and analyze peaking needs and how to best meet those needs.

Performance: As the company's resource deficit approaches, PacifiCorp is evaluating options such as pumped storage, SCCT and intermediate-load resources such as dispatchable CCCT's to meet peaking needs. This evaluation will examine the advantages of each resource according to system operations and overall cost. The company can use its operations model to determine the least-cost choice and best location for peaking resources at a given time.

6) Pursue peak management opportunities.

a) Consider pumped storage as a possible peaking option.

Performance: See 5 b) and 5 e).

b) Continue the new amorphous core transformer program, under which the company acquires lower-loss transformers. Evaluate and implement, as appropriate, the use of larger conductors, reconfiguration of selected feeders and the installation of additional capacitor banks.

Performance: PacifiCorp recognizes the value of reduced losses in distribution transformers. The company considers the life-cycle cost of these losses when evaluating the total cost of new transformers.

Amorphous core transformers offer substantial loss reductions over traditional silicon steel core transformers and have been part of PacifiCorp's program for several years. The company has used these transformers fairly extensively in the Idaho and Utah service territories since 1990. The company's new purchasing agreements with transformer trade allies, initiated in September 1993, have made it economical to expand the use of amorphous core transformers to all of the PacifiCorp system. Under this alliance agreement 75 percent of the transformers bought in 1994 were amorphous core transformers. The new equipment increased transformer efficiency by 21 percent.

c) In the next general rate case filing in each state, offer standard tariff time-of-day differentiated prices for industrial customers of over 1 MW for both demand and energy. This will provide appropriate price signals to customers consistent with the company's costs and may help increase the company's system load factor.

Performance: The only two states in which the company filed a rate case since the RAMPP-3 report are Oregon and Wyoming. The 1995 Oregon rate case includes a proposal to raise demand charges more than energy charges to better reflect demand costs. It also includes a proposal for a number of residential time-of-day options. PacifiCorp will propose to retain its current time-of-day demand charge differentiation for industrial customers and to not offer a time-of-day energy charge. This proposal resulted from discussions with industrial customer groups. In the 1995 Wyoming rate case the company proposed to retain its current time-of-day demand charge structure in order to minimize customer impacts. The filing proposes expended service offerings for industrial customers receiving transmission-level service and includes more price options to general service customers to encourage higher load factors.

d) Evaluate the costs and benefits of alternative levels of service quality, and develop various services that meet customer needs at prices acceptable to participating customers.

Performance: PacifiCorp has presented proposals for alternative levels of service quality at a number of meetings with customers. The company continues to pursue offering additional services to meet customer needs. These ideas develop from the company's meetings with individual customers to assess their service needs.

e) Promote the current option for time-of-day service to electric space and water heating customers in Utah.

Performance: PacifiCorp conducted a direct mail promotion of the Utah residential time-of-day service. That mailing targeted about 1200 customers. The promotion resulted in a minimal increase in participation in time-of-day service.

f) Determine how residential customers respond to better data on their power usage through a pilot project in Portland, Oregon. This will help the company better understand how customers use information on real-time energy uses.

Performance: PacifiCorp has developed and installed energy monitors in residential customer homes as part of its Portland distribution automation pilot project. The monitors allow customers to view current usage and cost, the previous day's usage and cost, month-to-date usage and cost, and the previous month's usage and cost. In addition, the monitors provide time-of-day price information, along with a budget alert the customer can program and a load control alert.

The last of the customers to have an in-home energy monitor were connected to the communication system in October 1995. Time series energy usage data has been gathered on most of these customer since mid-August. By November 1996 the company should have enough data from the 50 participants (25 with monitor and a time-of-day (TOD) rate and 25 with monitor only) and the 25 non-participants to complete a quasi-experimental comparison. The TOD rate will go into effect in November 1995 and will be charged on the December 1995 bill. Monthly billing data for one year before (October 1994 to September 1995) and one year after (October 1995 to September 1996) will be compared to determine if energy usage has changed. The total energy supplied to the neighborhood (200 homes) on primary distribution has been monitored on a 15 minute basis since August 1994. Total usage over the same periods will be compared.

g) Continue to offer current options for irrigation load control in Idaho and Utah. In the next general rate case filing in each state, offer time-of-day service for irrigation customers.

Performance: PacifiCorp continues to offer current options for irrigation load control in Idaho and Utah. It has modified the program to further enhance operating efficiency. Customer reaction during the

Oregon general rate case has prompted the company to not pursue time-of-day service for irrigation customers in Oregon.

h) Identify targeted geographic areas with constrained transmission and distribution capacities. Evaluate the possibility of using direct load control.

Performance: See item 2 h) above.

7) Implement pricing changes to further promote economic and energy efficiency.

a) In future general rate case filings in Montana and Utah, eliminate declining block energy price structures for residential customers by increasing energy charges.

Performance: PacifiCorp has not had any rate filings in Montana or Utah since publication of the RAMPP-3 report. Due to declining marginal costs, the company is re-evaluating the appropriate rate design for residential customers.

b) In future general rate case filings, implement price design changes which better reflect costs and assist customers to improve the efficiency of their use of electric power.

Performance: The 1995 Oregon rate case includes a proposal to raise demand charges more than energy charges to better reflect demand costs. The company has also proposed a number of residential time-of-day options.

8) Continue to increase system efficiency through improvements to the company's current generation, transmission, and distribution systems.

Performance: The company upgraded units at the Hunter, Huntington, and Wyodak plants for increasingly reliable operation. In addition, PacifiCorp is planning to install blade modifications to 10 General Electric turbines over the next five years. This will increase generation by about 150 MW, as well as the associated baseload energy, with only a small increase in fuel consumption.

New runners are being installed on the Yale hydro units in 1995-96 to achieve higher capacity and efficiency. Similar changes are being considered for other units.

The company has achieved the transmission and distribution system efficiencies scheduled for 1994 and 1995.

9) Continue to test and demonstrate small-scale carbon offset projects.

Performance: PacifiCorp continues to implement its pilot efforts to test low-cost methods of offsetting CO2 emissions. While the offset projects are small, they have been useful in demonstrating cost-effective methods to offset emissions. The pilots have also helped the company learn how to implement these projects by contracting with landowners and developing partnerships for implementation. As part of the Climate Challenge agreement with the U.S. Department of Energy, PacifiCorp agreed to spend $1 million on carbon offset projects from 1995 through the year 2000.

The trees planted as part of the Salt Lake City shade tree planting program are not yet yielding significant DSR benefits. Projections indicate that savings from all the homes involved in the program will total 99,420 kWh each year. This figure assumes savings of 477 kWh per year for each of 175 single-family homes with conventional air conditioning, 86.7 kWh per year for each of 175 single-family homes with evaporative cooling and 77.25 kWh per year for each of 10 multi-family dwellings.

Total system-wide CO2 emissions in 1994 were estimated in RAMPP-3 at 50,393,000 tons. PacifiCorp's three pilot-scale domestic forestry-based programs will result in carbon offsets of approximately 2,300 tons of CO2 per year for the next 10 years and more thereafter. The Belize project (see below under item b) will result in approximately 50,000 tons of CO2 offsets per year for the next 20 years. The Parallel Products project will result in 22,659 tons of offsets per year through 1999, and 36,146 tons CO2 in 2000. Preliminary estimates of the offsets associated with coal ash recycling are approximately 110,000 tons of CO2 per year. In the year 2000, currently in place offsets are projected to total close to 200,000 tons of carbon dioxide. While the total amount of CO2 that has been offset is modest, PacifiCorp believes the goals of testing a variety of low cost offset techniques and learning about barriers to implement these projects are being met.

.4% of total or 1.6% reduction
DSR achieves 803,000 or

#13 vs #11
1102360
55,118,000

1,118,415
55,921,000
803,000 saved

a) Reforest fire-damaged land in eastern Washington and western Idaho.

Performance: The company helped landowners plant trees on 560 unforested acres, in cooperation with the Council of the Upper Columbia Resource and Conservation Development Area. A major fire depleted the seed stock on the privately-owned land. Landowners received reimbursement for 75 percent of the costs for site preparation and planting. In return, they signed a contract agreeing to not harvest their trees for 80 years. The contract allows for thinning, but requires that seed trees remain for 120 years for regeneration.

b) Work in cooperation with the US Environmental Protection Agency to forest unplanted lands in the Sartov region of Russia.

Performance: PacifiCorp's contract negotiations with officials in the Sartov region failed to result in a carbon offset project. However, the company continues to explore other promising international projects. One possible project involves protection of threatened tropical forest land in Belize. The U.S. Initiative on Joint Implementation approved the project. Several agencies are cooperating in its development: The Nature Conservancy, the Program for Belize, and a small group of U.S. utilities.

c) Plant shade trees in Salt Lake City neighborhoods with the assistance of the TreeUtah organization.

Performance: PacifiCorp worked with the non-profit TreeUtah organization to plant more than 1,400 urban trees in a variety of Salt Lake City neighborhoods. The company discovered that planting shade trees in a rural area is a more cost-effective way to achieve CO2 offsets than planting them in Salt Lake City.

d) Help non-industrial landowners in Oregon plant under-stocked lands through a partnership with the Oregon Department of Forestry.

Performance: PacifiCorp has conducted two separate pilot projects to plant trees on under-stocked lands in Oregon. First, the company worked with the Oregon Department of Forestry to plant 630 acres. The contract with landowners required the company to pay for all site preparation and planting costs. In return, landowners agreed not to harvest their trees for at least 65 years. The second Oregon project involved buying carbon offsets from the newly created Forest

Resources Trust. The Oregon Legislature created the Trust to help reforest 250,000 acres by 2010. Landowners who are paid by the Trust to replant their land must repay the Trust with a portion of the proceeds from the eventual harvest. The state will track the carbon accumulated on private lands under Trust agreements. The landowners can then sell the offsets to investors interested in developing projects that need carbon offsets.

10) Improve the RAMPP process for use in RAMPP-4.

a) Implement feasible process improvements identified in the RAMPP-3 regulatory acknowledgment review.

Performance: Chapter 2 addresses the company's response to each of the items identified in the RAMPP-3 acknowledgment review.

b) Improve the company's ability to evaluate capacity needs in the RAMPP analysis.

Performance: The addition of summer peaks to the modeling process was the most significant improvement in the company's ability to evaluate capacity needs. The RAMPP-4 database also included a summer peak purchase option, which improved the model's ability to select cost-effective choices to meet the company's peaking needs.

c) Add to the IPM model's abilities so that it can recognize, and add resources to meet, both winter and summer peaks.

Performance: RAMPP-4 modeling recognizes both winter and summer peaks. This change proved to be important and appropriate since RAMPP-4 results confirmed that summer peaking needs drove most of the model's resource additions.

Chapter 6: RAMPP-4 Action Plan

This chapter describes the RAMPP-4 action plan and its development. It concludes with sections that link the modeling results with each item in the RAMPP-4 action plan, provide more detail for the DSM in the action plan, and identify benchmarks for monitoring the RAMPP-4 action plan.

RAMPP-4 Action Plan

1) **Demand Side Management**: Implement the amount of demand side activity consistent with a competitive utility environment, considering cost and financial and price impacts. Achieve 23 MWa of installed cost-effective savings by 1996, 25 MWa by 1997, and 28 MWa by 1998.

    a) Identify and pursue opportunities to target DSM to areas that will allow the company to reduce its transmission and distribution costs.

    b) Pursue ways to increase participant contribution to DSM costs and develop alternative funding sources.

2) **Peaking Resources**: Evaluate alternative ways to meet peaking needs and pursue opportunities that meet system needs cost-effectively.

    a) Continue to evaluate opportunities for managing peaking needs. Implement those which are cost-effective.

    b) Use the market to find cost-effective opportunities to purchase summer peaking power.

    c) Evaluate opportunities to meet the company's peaking needs through peaking resources such as pumped storage, SCCTs, purchased power and existing peaking resources.

3) **Baseload Resources**: Evaluate alternative ways to meet baseload needs and pursue opportunities that meet system needs cost-effectively. It is unlikely that the company will need to make a decision to acquire new baseload resources during the three-year action plan period. However, PacifiCorp will pursue opportunities in all of the following three areas. The company will acquire only those resources that benefit the system, either by providing power needed for retail loads, or power that can be profitably sold on the wholesale market.

   a) Work with customers to identify their needs and find environmentally responsible solutions. In some cases this may mean cogeneration.

   b) Continue to monitor the wholesale market for opportunities to purchase power at prices lower than other resource acquisitions.

   c) Continue to evaluate cogeneration and CCCTs with independent developers. Pursue agreements or options where cost-effective.

4) **Existing System**: Continue to make cost-effective improvements to the existing system.

   a) Continue to evaluate opportunities to enhance generation efficiency on the existing system and implement them when cost-effective.

   b) Continue with the turbine upgrades that have been identified as cost-effective.

   c) Continue with plans to bring the Hermiston plant on-line by 1997.

   d) Continue evaluating to determine the cost-effectiveness of converting the Gadsby plant to a combined cycle unit. Pursue the conversion if cost-effective and if the system needs the generation.

   e) Continue to implement transmission and distribution system efficiencies as identified to be cost-effective.

5) **Renewables**: Pursue low-cost activities that increase the company's knowledge of renewable resources. PacifiCorp may choose to build or purchase additional renewable resources, depending on their cost-effectiveness at the time.

   a) Continue with plans to bring the Foote Creek, Wyoming, and Columbia Hills, Washington, wind projects on-line in 1996. Once these projects are operating, evaluate their performance and cost-effectiveness.

   b) Continue to evaluate other potential wind projects. Pursue agreements for developing more wind projects if they are cost-effective compared to other resources.

   c) Continue to evaluate potential geothermal projects. Pursue agreements to bring 25-50 MW of geothermal resources on line if they are cost-effective compared to other resources.

   d) Analyze geographic areas with constrained transmission and distribution capabilities. Pursue cost-effective opportunities to relieve constraints through the use of distributed generation technologies.

   e) Continue to monitor global climate science.

   f) Continue evaluating the cost-effectiveness of small-scale carbon offset projects.

   g) Continue to participate in Solar II.

   h) Continue to monitor the performance of the company's solar PV projects.

   i) Continue participation in the Northwest Regional Solar Radiation Data Monitoring Project.

   j) Continue to support the OSU Wind Research Cooperative.

6) **Clean Coal Technologies**: Continue to evaluate clean coal technologies, including IGCC and fluidized bed, for their ability to meet resource needs in an environmentally acceptable way and at low cost.

7) **Other Opportunities**: Seek and pursue cost-effective resource acquisition opportunities that meet the future needs of the company. PacifiCorp should seek and pursue opportunities such as the Colorado-Ute acquisition, which the RAMPP process did not anticipate. Colorado-Ute has become a low-cost resource for the company and a significant benefit to customers.

8) **Competitive Market**: Continue to be a low-cost provider and a successful competitor in the marketplace.

9) **IRP**: Continue to improve the RAMPP process and work to modify IRP to be a more effective tool.

   a) Implement feasible process improvements identified in the RAMPP-4 regulatory acknowledgment review.

   b) Evaluate other IRP models to assess the relative benefits of code improvements to IPM versus a different model to achieve the goals of RAMPP-5.

   c) Evaluate the implication of the FERC NOPR for resource planning and implement appropriate changes to RAMPP modeling.

   d) Work with regulatory agencies and other parties to modify IRP to make the process more valuable to utilities and their customers operating.

Development of the RAMPP-4 Action Plan

PacifiCorp uses its RAMPP action plans to guide rather than dictate future actions. The model picked resources on one criteria -- their ability to lower total costs over a 50-year period. This provides useful information to the company, but management makes its decisions on other criteria as well, such as price impacts, resource operability, fit with the existing system, and future uncertainties and risks. In addition, any specific actions will depend on opportunities and conditions at the time. Therefore, the action plan does not provide a blueprint for specific actions. PacifiCorp does not know what opportunities will become available in the three years covered by the

RAMPP-4 action plan, nor how each opportunity will compare to others available at that time. The company follows the overall direction of the action plan while allowing itself flexibility to respond to changing conditions.

When thinking about decisions to meet resource needs, PacifiCorp management realizes that every resource has its pros and cons. DSM carries the risk of uncertain performance, uncertain customer retention, and an uncertain ultimate cost. Gas-fired resources carry the risk of uncertain gas prices in the future. Cogeneration carries the risks of uncertain negotiations with customers or other developers and uncertain gas prices. Coal resources carry the risk of uncertain future taxes or restrictions on carbon dioxide emissions. Clean coal technologies, which can reduce the carbon dioxide risk, carry the risk of a new, not thoroughly proven technology. Renewable resources carry the risk of uncertain performance and ultimate cost. All new supply-side resources carry siting risks. Purchased power on short-term contracts carries the risk of future cost increases. The company's management must weigh each of these risks against the anticipated benefits of each resource in making its ultimate decisions. Those decisions often depend on the opportunities that become available to the company, and typically require much more extensive financial and operational analysis than can be accomplished within RAMPP. RAMPP provides a first step in a careful analysis and evaluation process the company uses before making an acquisition. RAMPP provides the framework and benchmark against which the company evaluates resource opportunities.

Utilities are changing the way they are planning to meet their customers' energy needs. PacifiCorp believes wholesale market prices will be soft for five to seven years with surplus capacity and low incremental prices. The increased availability of power on the wholesale market reduces the need for utilities to build and own plants. This will occur through increased transmission access due to FERC actions, new generating plants coming on-line from utilities and independent developers, and the development of merchant plants.

The single most significant principle in the RAMPP-4 action plan is this: the wisdom of postponing decisions. The company has decided to find all cost-effective alternatives to postpone and/or mitigate the need for capital expenditures to meet firm load requirements. This is a prudent strategy now. It appears to the company that the cost of acquiring power is declining due to increasing competition in the generation market and increasing transmission access due to FERC actions. If the company's perception is accurate, postponing resource decisions is likely to lead to lower-cost opportunities. The only resource actions that absolutely should occur in the current three-year action plan period are DSM. PacifiCorp will monitor load growth and economic conditions to determine whether it should adjust the amount of DSM as the action plan period progresses.

In developing the RAMPP-4 action plan, the company focused on the next 10 years. Although RAMPP uses a 20-year planning horizon, with end effects for an additional 30 years, PacifiCorp believes it is very difficult to plan more than five or ten years in advance because of market and industry uncertainties. The changes occurring in the electric industry suggest that all of today's assumptions may be outdated in five to ten years. The company has been observing the natural gas industry, and the changes that have occurred with deregulation and increasing competition. An open gas market has created rapid and radical shifts in supply and price forecasts. A free and open market makes forecasting very difficult and longer-term predictions more unreliable. However, it is useful to understand resource needs over a 10-year period to better evaluate low-cost opportunities as they occur.

The RAMPP-4 draft action plan reflects the results of model runs, the company's perceptions about the future as discussed in Chapter 1, and concerns of the public advisory group. Over the next 10 years, the model selected DSM, summer peak purchases, and gas-fired resources. This would suggest an action plan that only included activities in those three areas. However, the company broadened its action plan to include activities in other areas, to better prepare for the uncertain future it foresees. The action plan includes six additional action or evaluation items that appear to be low-cost and prudent courses of action: existing system improvements, renewables, clean coal, other opportunities, competitiveness, and improving RAMPP-5.

The next RAMPP report will be due at the end of 1997. The company anticipates that with an additional two years of experience in a more competitive environment, it will better understand the impacts of FERC rulings, proceedings in various states to implement alternative regulation, investigations and experiments in several states on retail wheeling, and the impacts of competition.

Linking the Action Plan to the Model Run Results

The following discussion identifies each action plan item, and the model run results that support it. Assuming medium load growth, in the next 10 years the model added DSM, short-term summer peaking purchases, and gas-fired baseload resources. The modeling results also supported planned turbine upgrades and addition of the Hermiston plant. They did not support immediate activities for acquiring renewables, coal-fired resources, or transmission upgrades.

Under medium load growth, the company does not need new resources until the year 2002 for summer peak, until 2003 for winter peak, or until the year 2003 for baseload gas-fired resources. These dates were the same in the base case and in the case with DSM costs reduced by 15 percent (the case that provided the base for DSM activities in the action plan). This time frame means the company does not have to make any supply-side resource decisions in the three years covered by the RAMPP-4 action plan (1996, 1997 and 1998). Peak purchases require less than one year of lead time, requiring a decision for 2002 by 2001. Gas-fired resources have a four-year lead time, requiring a decision for 2003 by 1999.

PacifiCorp recognizes there is uncertainty in the timing and amount of resource needs. Under medium-low load growth, the model added no new resources in the next 10 years. Under medium-high load growth, the model added more DSM and more gas-fired resources, and it added them earlier. For the environmental sensitivity cases or a substantial decrease in the cost of renewables, the model also added renewables. Therefore, a prudent course of action is for PacifiCorp to carefully watch key indicators to determine whether the action plan needs modification. The last section of this chapter identifies benchmarks the company will be monitoring during the three-year action plan period.

<u>DSM Activity</u>

In developing the RAMPP-4 action plan, the company first considered the issue of DSM activity. In RAMPP-3 the company "hardwired" alternative levels of DSM into the IPM model. Using this technique, the company could test various levels of DSM under alterntive assumptions, but could not determine the optimum level of DSM under a given set of assumptions. In RAMPP-4 the model selected the amount of DSM that was optimal under a given set of assumptions.

Under medium load growth and the base case assumptions, the model added 20 MWa of DSM in 1996, 22 MWa in 1997, and 24 MWa in 1998, for a total of 66 MWa. However, the company did not use these results to determine the amount of DSM in the RAMPP-4 action plan. Instead, the company adopted the amount of DSM selected in the case with DSM costs reduced by 15 percent (case #13). The 15 percent reflects the 10 percent Regional Act credit and an additional 5 percent for avoided investment in transmission and distribution. In case #13, with DSM costs lowered by 15 percent, the model selected 23 MWa of DSM in 1996, 25 MWa in 1997, and 28 MWa in 1998, for a total of 76 MWa of DSM over the three-year action plan period.

The company decided to use the DSM amounts in case #13 for three reasons: 1) the advisory group supported that case and using the DSM amounts from it would result in an agreement on DSM for RAMPP-4, 2) the difference in amount of DSM between the base case #1 and case #13 was only 10 MWa over the three-year action plan period, and 3) the extra 10 MWa caused no greater price impact than did the amount of DSM from base case #1. Graph 6-1 shows the amount of DSM selected by the model in base case #1 versus case #13.

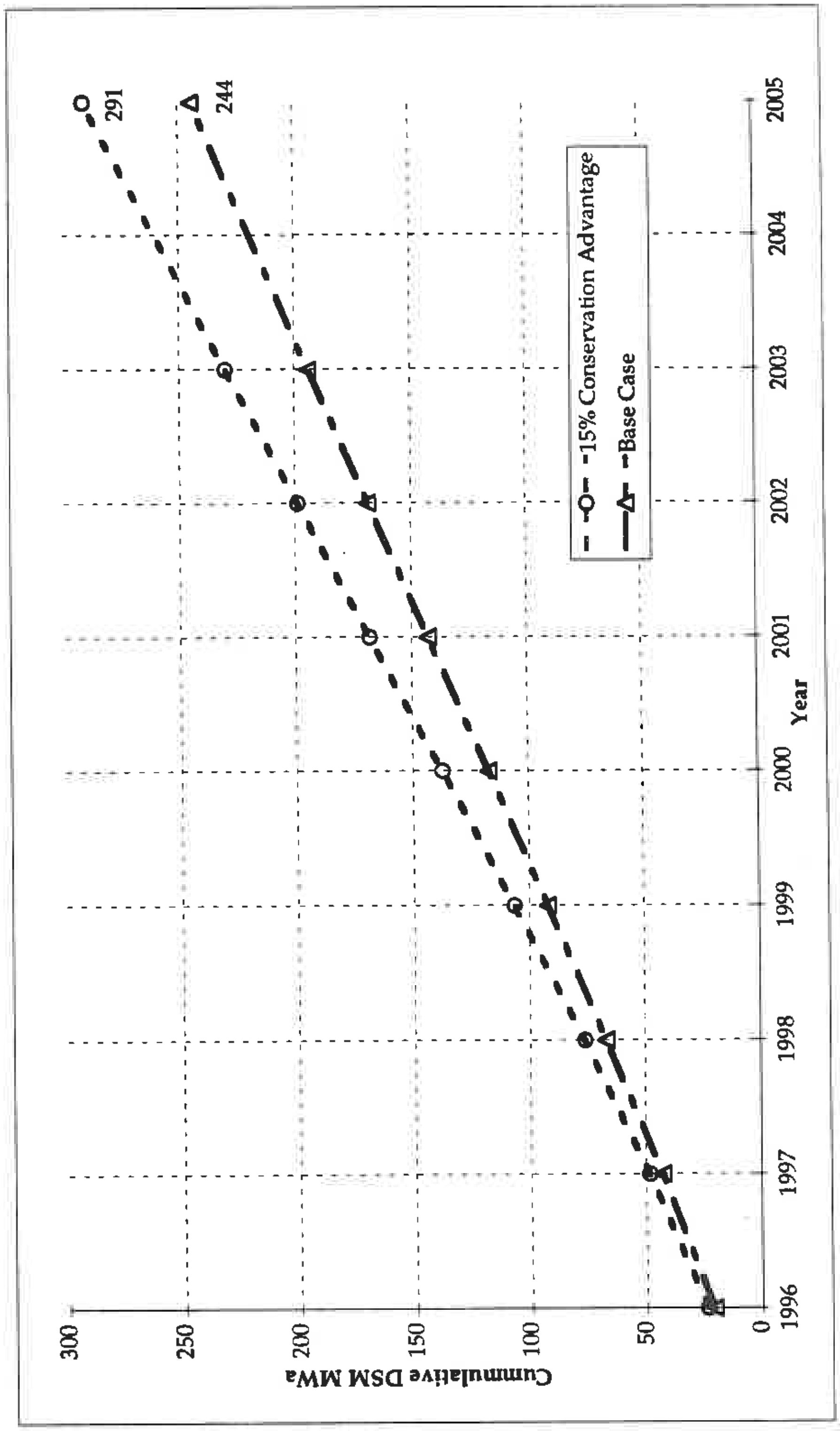
Looking only at resource needs, the company does not need to acquire any new resources or any DSM savings in the next two or three years. However, stopping all DSM activity for that time period would have adverse consequences for future DSM success. Customers need more consistent signals from the company, and the company needs to maintain its capability and expertise in the area. The model added DSM in the next three years (1996, 1997, and 1998) because ramp-up constraints required beginning programs now to have a sufficient amount of DSM in place when needed. Therefore, the action plan includes the levels of DSM activity selected by the model from case #13.

PacifiCorp compared the levels of DSM selected by the model in all 37 cases. Most of the cases had very similar levels of DSM; i.e., the model's selection of DSM amounts tended to be unaffected by most of the modeling assumptions. The amount of DSM selected in 29 of the 37 cases fell within 10 MW of the base case over the first 10 years. Inputs that caused the DSM amount to vary beyond that level were load growth, DSM cost assumptions, and environmental adders.

Cumulative DSM (MWa)

Graph 6-1

By DSM Level



Under medium load growth, only five cases had higher DSM levels than the base case: the three environmental adder cases, case #12 with a 20 percent cost reduction for DSM inputs, and the case with lumpy resource additions. Graph 6-2 shows the amount of DSM selected by the model under alternative assumptions about load growth, gas prices, and environmental adders. Load growth caused the most variation in DSM selection: there was more than a 200 MWa difference in the amount of DSM selected after the first 10 years between the medium-low and the medium-high cases. Changes in gas prices and environmental adders caused a variation of 50 to 75 MWa in the level of DSM selected by the end of the first 10 years. PacifiCorp will need to watch all of these indicators, especially load growth, during the next three years to evaluate any need to modify its DSM efforts.

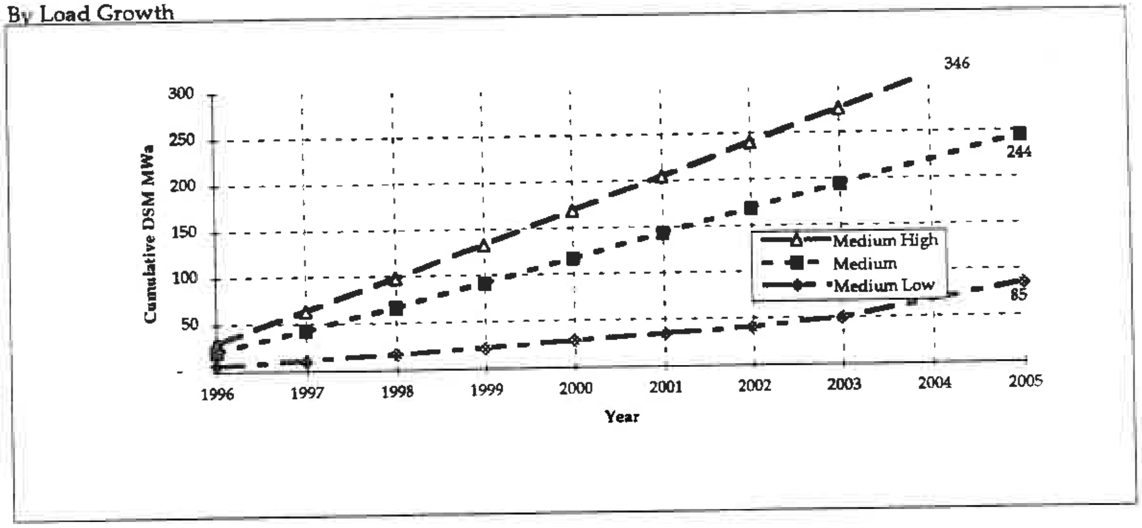
PacifiCorp's financial analysis of DSM programs did not influence the amount of DSM recommended in the action plan. However, the financial analysis will continue to help the company rank and prioritize DSM projects. It is the same analysis the company uses to rank all capital expenditure projects: for DSM, supply-side resources or other opportunities. The financial model calculates the internal rate of return (IRR) of the unleveraged cash flows (the cash flows prior to financing). IRR is the discount rate at which the net present value of the cash flows is zero.

The financial analysis of DSM programs uses cash flows as if PacifiCorp were unregulated. It takes into account current wholesale market prices and current gas prices. The analysis also considers lost revenue and price impacts of DSM initiatives. Inputs to the cash flow analysis include cash outflows for DSM and DSM cash inflows. Cash outflows are DSM program costs, including O&M expenses, deferred expenses, grants and rebates, and ESc loans; revenue reduction from lower sales due to DSM programs; and any increases in income tax. Cash inflows include ESc loan repayments from the Energy Service charge (ESc), power cost savings (the cost of electricity the company would not have to produce because DSM was meeting those customer needs) adjusted for line losses, a 15 percent adder for the intangible benefits of DSM and avoided T&D investments, and any reduction in income taxes.

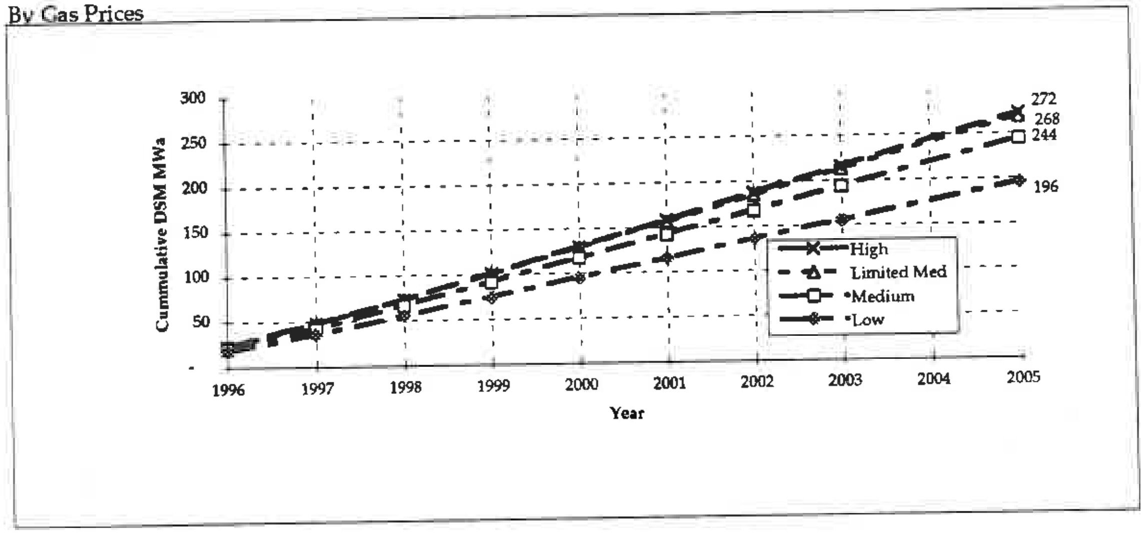
The company performed a financial analysis of DSM over a year ago for RAMPP-3. That analysis showed that many of the RAMPP-3 DSM programs achieved the preferred IRR of 9 percent; however, since then, Cumulative DSM (MWa)

Graph 6-2

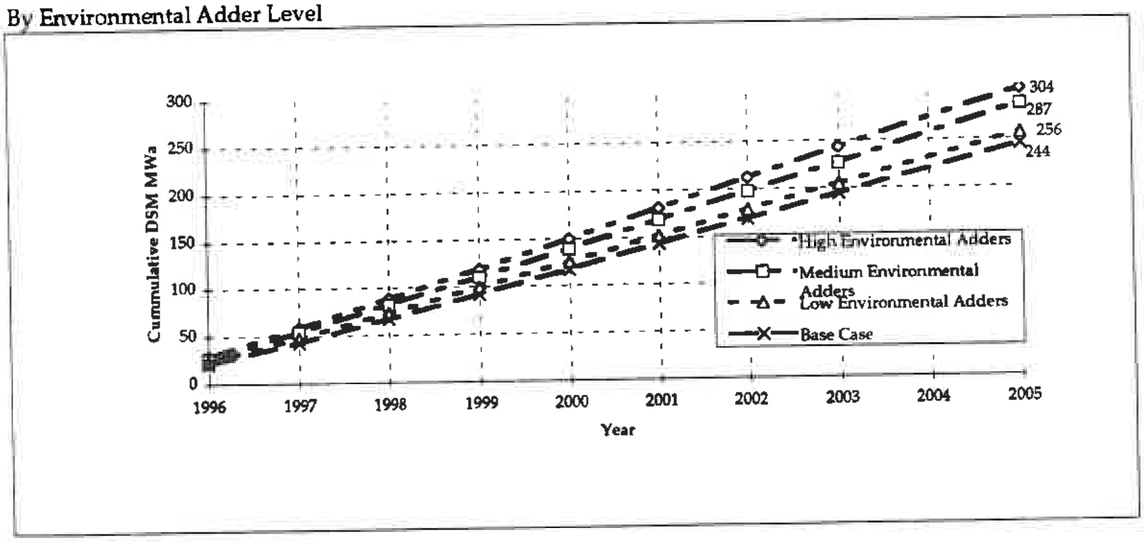
By Load Growth



By Gas Prices



By Environmental Adder Level



lower non-firm market prices and lower gas prices have decreased the relative benefits of DSM. The financial analysis of the RAMPP-4 DSM programs showed that none of them achieved the 9 percent IRR. Therefore, the company did not use the results of this financial analysis to determine the amount of DSM in the RAMPP-4 action plan. However, PacifiCorp believes the financial analysis is still useful, for it indicates which programs produce a higher IRR and, therefore, where the company should focus its efforts. It also shows which programs produce lower IRRs; this is where the company needs to reduce the cost of the programs and/or increase the savings from measures in the programs to improve their IRRs.

Summer Peak Purchases

The second item in the RAMPP-4 action plan addresses summer peak needs. Although PacifiCorp's retail load remains winter peaking, summer peak needs drove the model's resource additions. This is because the company has more resources available to meet winter peak needs than summer peak needs. If the company were to negotiate a summer peaking contract similar to the SCE winter peaking contract, that situation would change.

In evaluating the choices for summer peaking needs, the company determined that the least-cost approach is a summer-only peak purchase for 2002. In 2003, when the company expects to also experience winter peak and energy needs, then a more traditional resource would be a more cost-effective choice.

In evaluating the need for summer peaking resources, the company compared the amount of summer peaking resources added by the model for each year of the first 10 years of the planning period in all of the cases. Table 6-3 shows the year-by-year summer peak purchases added by the model to meet the summer reserve margin requirement for all of the cases. It indicates that the company does not need summer peaking resources until 2002 unless load growth increases beyond the medium two percent level. The cases that required summer peaking resources sooner are unlikely to occur (the no Hermiston cases, the no DSM case and the no-turbine upgrade case), or they are cases that resulted from a modeling experiment (extension of some inputs into the end-effect years).

Summer Season Peak Purchase

Summer Incremental MW

Table 6-3

Sorted by the year 2002

Case Number	Study Title	Study Year						
		1996	1997	1998	1999	2000	2001	2002
22	Med High Load - Med Gas	277	38	201	393	500	500	500
7	Med Load High Gas Without Hermiston	-	-	-	101	327	332	372
6	Without Hermiston	-	-	-	110	342	354	343
67	Extension of All Modeling to 2045	-	-	-	-	83	183	315
65	Extension of all Existing Firm Wholesale Contracts	-	-	-	-	72	170	308
11	No DSM	-	-	-	-	104	157	274
5	No Turbine Upgrades	-	-	-	-	48	69	166
14	15% Conservation Disadvantage	-	-	-	-	-	-	130
42	25% Lower Non-Firm Market Prices	-	-	-	-	-	-	127
50	Underbuild - 25% Lower Non-Firm Market Prices	-	-	-	-	-	-	121
66	Extension of Loads & DSM to 2045	-	-	-	-	-	-	116
51	Underbuild - Medium Non-Firm Market Prices	-	-	-	-	-	-	112
52	Underbuild - 25% Higher Non-Firm Market Prices	-	-	-	-	-	-	112
1	**Base Case**	-	-	-	-	-	-	109
58	Added Transmission - Bridger to OWC	-	-	-	-	-	-	109
59	Added Transmission - Utah to OWC	-	-	-	-	-	-	109
57	Test of Transmission Plant Conversion	-	-	-	-	-	-	88
34	High Gas - with Medium Non-firm Market Prices	-	-	-	-	-	-	63
13	15% Conservation Advantage	-	-	-	-	-	-	62
12	20% Conservation Advantage	-	-	-	-	-	-	47
41	Resource Lumpiness	-	-	-	-	-	-	33
31	Med Load - Low Gas	-	-	-	-	-	-	30
21	Med Low Load - Med Gas	-	-	-	-	-	-	-
32	Limited Gas (500 MW) at Med Esc	-	-	-	-	-	-	-
33	Med Load - High Gas	-	-	-	-	-	-	-
4	No Summer Season	-	-	-	-	-	-	-
43	25% Higher Non-Firm Market Prices	-	-	-	-	-	-	-
44	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	-	-	-	-	-	-	-
45	250 MW Plant in 1999 - Medium Non-Firm Market Prices	-	-	-	-	-	-	-
46	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	-	-	-	-	-	-	-
47	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	-	-	-	-	-	-	-
48	500 MW Plant in 1999 - Medium Non-Firm Market Prices	-	-	-	-	-	-	-
49	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	-	-	-	-	-	-	-
61	Renewables at 35% of Capital Cost	-	-	-	-	-	-	-
71	Low Environmental Adders	-	-	-	-	-	-	-
72	Medium Environmental Adders	-	-	-	-	-	-	-
73	High Environmental Adders	500	500	500	-	-	-	-

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Summer peaking needs occur in 2002 without associated winter peak or energy needs. Beginning in 2003 the system needs resources to meet summer peaks, winter peaks, and energy requirements. Since summer peak needs occur without other system needs for one year, the most cost-effective solution is short-term summer-only capacity purchases on the wholesale market for 2002. The lead time for such contracts is less than one year. Therefore, the company does not have to make a decision on whether to pursue these resources until 2001, well beyond the three-year action plan period for RAMPP-4. For this reason, the action plan does not include a specific amount of summer peaking purchase or acquisition.

PacifiCorp will need to watch load growth as the action plan period progresses to evaluate any need to modify the timing and amount of summer peak purchases. The company will also need to carefully monitor the wholesale market, looking for opportunities to reduce its peak needs and to meet expected peak needs with low-cost solutions. When the company is a year away from needing summer peaking resources, it will evaluate the amount needed and begin talking to possible suppliers.

The RAMPP-3 action plan included a recommendation to develop additional peaking resources including simple cycle CTs and pumped storage. RAMPP-4 modeling selected simple cycle CTs only in the underbuilding cases (Cases #50, #51, and #52) and the renewable resource case (Case #61). The model never selected pumped storage. For this reason, the RAMPP-4 action plan does not include acquisition of these traditional peaking resources.

<u>Gas-Fired Baseload Resources</u>

After considering DSM and peaking needs, PacifiCorp evaluated its need for baseload resources. Under medium load growth and medium gas prices the system needs 635 MW of baseload resources in 2003 through 2005. Gas-fired baseload resources have a four-year lead time. Therefore, baseload needs beginning in 2003 requires a decision in 1999, after the three-year action plan period for RAMPP-4. However, considering future uncertainty in load growth and in the industry, the company concluded that it should carefully monitor both system needs and opportunities during the action plan period.

Graph 6-4 shows the amount of gas-fired baseload resources added over the first 10 years under each of the load growth cases and each of the gas price levels. Under medium-low load growth, the model selected no new baseload resources over the next 10 years; under medium-high load growth, the model selected 2,017 MW of gas-fired baseload resources over the next 10 years. If gas prices followed the low escalation rate, the model selected 697 MW; if gas prices followed the high escalation rate, the model selected 566 MW.

The need for gas-fired baseload resources is moderately sensitive to other input assumptions. Table 6-5 shows the amount of gas-fired resources added by the model in each of the cases for each of the first 10 years. The amount added by the model in 16 of the 37 cases falls within a range of plus or minus 100 MW from the base case. Events that would create a reduction in gas-fired needs would be: lower than expected load growth, lower non-firm market prices, significantly lower renewable resource costs, or high natural gas prices. Conditions that would create a need for more gas-fired resources would include any environmental adders, higher than expected load growth, the extension of existing firm wholesale sales contracts, higher than expected DSM costs and lower natural gas prices. Graph 6-6 shows the amount of gas-fired resources added according to DSM cost level, non-firm market price, and level of environmental adders.

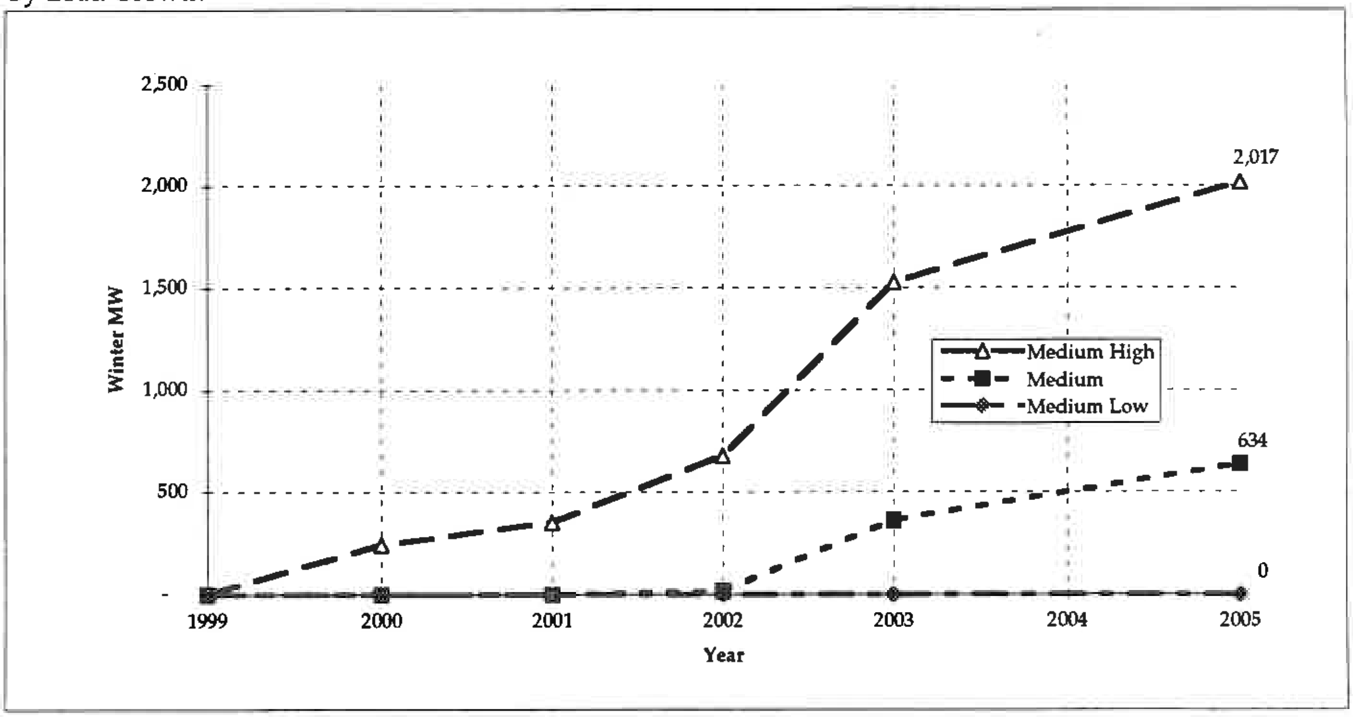
Because the company does not have to make a decision for baseload gas-fired resources during the action plan period for RAMPP-4, the action plan includes no specific amounts of gas-fired baseload resources. Depending on trends over the next few years, the company may need to do very little or may need to acquire substantial baseload gas-fired resources. The most prudent action approach for 1996 through 1998 is to carefully watch and evaluate load growth, gas prices, market conditions and opportunities that may develop.

PacifiCorp will continue to evaluate all gas-fired resource opportunities offered by developers and the wholesale power market. The increasingly active wholesale market and increased activity among project developers give the company more cost-effective choices than in the past. When PacifiCorp must make a decision, either because a cost-effective opportunity has become available, or the lead time for gas-fired resources requires a decision, the company will re-evaluate the amount of gas-fired resource acquisitions that will best meet system needs.

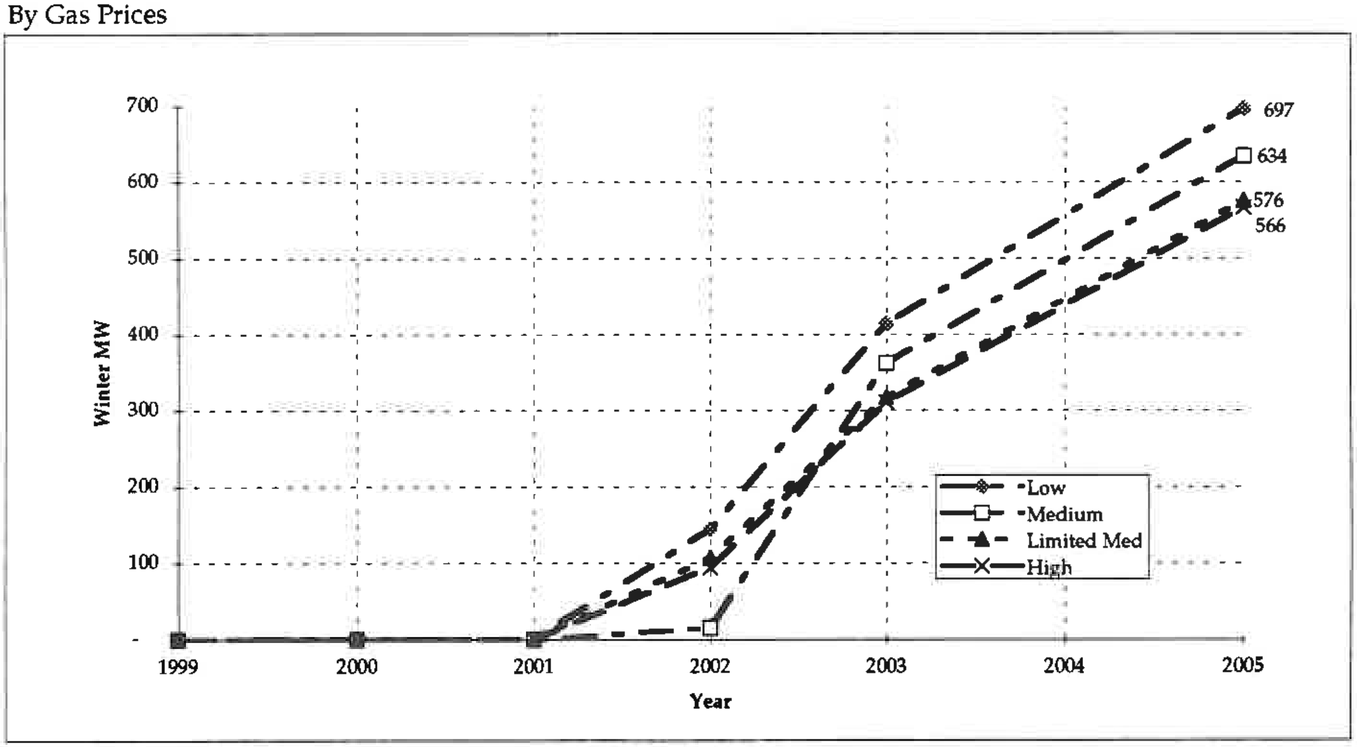
Cumulative Gas Fired Base Load Resources
Winter MW

Graph 6-4

By Load Growth



By Gas Prices



Gas Fired Base Load Resources Selected by Year

Winter Incremental MW

Table 6-5

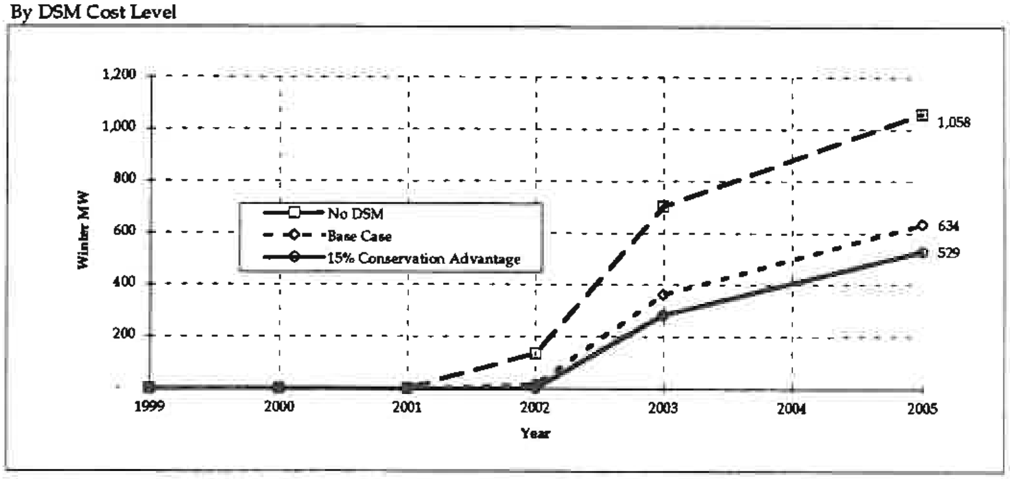
Sorted by Total MW

Case Number	Study Title	Study Year 1999	2000	2001	2002	2003	2005	Total MW
73	High Environmental Adders	-	1,966	1,658	497	317	37	4,475
72	Medium Environmental Adders	-	1,966	1,434	712	12	-	4,124
22	Med High Load - Med Gas	-	244	108	324	849	493	2,017
71	Low Environmental Adders	-	650	514	-	215	-	1,379
65	Extension of all Existing Firm Wholesale Contracts	-	-	-	64	557	479	1,101
67	Extension of All Modeling to 2045	-	-	-	72	566	459	1,097
6	Without Hermiston	-	-	-	223	596	272	1,091
11	No DSM	-	-	-	135	567	356	1,058
7	Med Load High Gas Without Hermiston	-	-	-	160	612	256	1,028
5	No Turbine Upgrades	-	-	-	111	408	271	789
14	15% Conservation Disadvantage	-	-	-	44	375	285	704
31	Med Load - Low Gas	-	1	-	143	270	283	697
49	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	500	-	-	-	151	37	688
66	Extension of Loads & DSM to 2045	-	-	-	33	355	272	660
41	Resource Lumpiness	-	-	-	85	262	304	651
44	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	250	-	-	-	117	280	647
46	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	250	6	52	80	256	3	646
47	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	500	-	-	-	-	145	645
42	25% Lower Non-Firm Market Prices	-	-	-	-	367	277	644
45	250 MW Plant in 1999 - Medium Non-Firm Market Prices	250	-	-	-	110	276	636
48	500 MW Plant in 1999 - Medium Non-Firm Market Prices	500	-	-	-	-	134	634
1	**Base Case**	-	-	-	15	347	272	634
58	Added Transmission - Bridger to OWC	-	-	-	15	347	272	634
59	Added Transmission - Utah to OWC	-	-	-	15	347	272	634
43	25% Higher Non-Firm Market Prices	-	161	127	101	201	42	633
57	Test of Transmission Plant Conversion	-	-	-	-	316	263	579
32	Limited Gas (500 MW) at Med Esc	-	-	-	107	210	259	576
33	Med Load - High Gas	-	-	-	94	216	256	566
52	Underbuild - 25% Higher Non-Firm Market Prices	-	-	-	-	-	553	553
13	15% Conservation Advantage	-	-	-	-	283	246	529
34	High Gas - with Medium Non-firm Market Prices	-	-	-	-	278	246	524
12	20% Conservation Advantage	-	-	-	-	266	246	512
61	Renewables at 35% of Capital Cost	-	-	-	-	151	213	364
4	No Summer Season	-	-	-	-	162	171	333
50	Underbuild - 25% Lower Non-Firm Market Prices	-	-	-	-	-	279	279
51	Underbuild - Medium Non-Firm Market Prices	-	-	-	-	-	274	274
21	Med Low Load - Med Gas	-	-	-	-	-	-	-

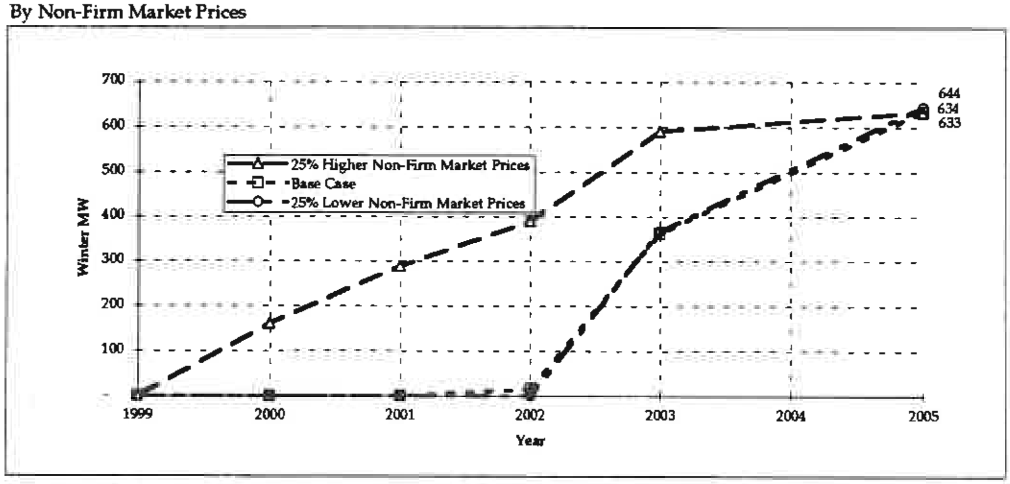
Cumulative Gas Fired Base Load Resources
Winter MW

Graph 6-6

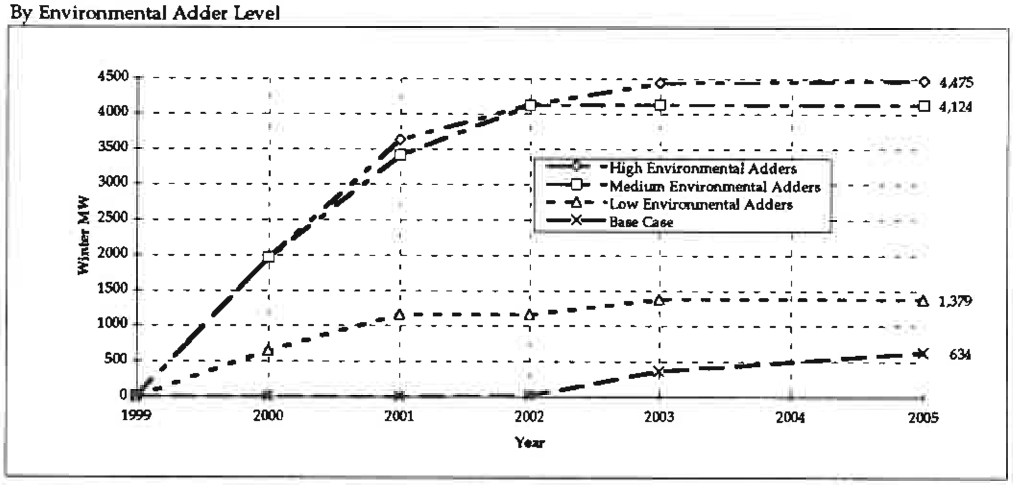
By DSM Cost Level



By Non-Firm Market Prices



By Environmental Adder Level



Existing System Improvements

The inputs for the RAMPP-4 modeling included turbine upgrades for some of the company's existing coal plants. Case #5 excluded this system improvement as a way to test whether upgrading the turbines was cost-effective. Before deciding to implement the turbine upgrades, the company performed more extensive and specialized analyses than are possible with the RAMPP modeling. For example, RAMPP-4 testing of the cost-effectiveness of the upgrades could not capture their heat rate advantage; it could only recognize the increased turbine capacity. Nevertheless, the company decided that testing the cost-effectiveness of the upgrades with RAMPP modeling would provide useful information for the company and regulators. The financial results for case #5 show that the company incurs a minor system cost increase -- $50 million in 50-year utility NPV -- if it does not upgrade the turbines. This result confirmed the system benefit of proceeding with the turbine upgrades.

The inputs for the RAMPP-4 modeling included the Hermiston plant in the existing system. Cases #6 and #7 removed the Hermiston plant from both the existing system and the portfolio of new resources. Case #6 assumed medium natural gas price escalation rates and Case #7 assumed high gas price escalation. An additional case, added after comments on the draft report, also removed the Hermiston plant and assumed low gas prices. RAMPP-4 included these three cases to test the cost-effectiveness of the Hermiston addition. Financial results for all three cases indicated that omitting Hermiston increased total costs. The savings from including the Hermiston plant in the existing system confirmed that it is cost-effective to the company.

The company believes it can improve the efficiency of the system through cost-effective improvements to the transmission and distribution system. Company engineers use the most current avoided costs to determine whether projects for upgrading lines offer efficiency opportunities as well. RAMPP modeling cannot incorporate these options as resources. However, the company's practice of using the most recent avoided costs provides a RAMPP-derived measure to evaluate them.

RAMPP-4 modeling tested the cost-effectiveness of new transmission in two ways: through the geographic conversion method, and through two cases that added transmission capacity to the system. The model did not select the geographic conversion method unless its cost was significantly lower than it would actually be. At current costs it would not be cost-effective. The two cases with increased transmission capacity added to system costs with no offsetting benefits. From these results the company concluded that building new transmission capacity is not cost-effective at this time.

Renewable Resources

Table 3-20 from Chapter 3 shows that the cost of wind ranges from 38 to 57 mills/kWh, depending on the transmission costs incurred. Geothermal costs are about 42 mills/kWh. They must compete with gas-fired resources that cost between about 23 and 31 mills/kWh. The model selected renewable resources only in the medium and high environmental adder cases, and under the assumption that capital costs for renewables are 65 percent lower than their current prices.

RAMPP-3 included an action plan item that stated: "Continue with actions necessary to have 200 MWa of renewable resources on-line by 2001, if cost-effective." With low-cost gas-fired resources available, the company does not feel renewable resources are a cost-effective choice. For this reason, the RAMPP-4 action plan does not include a specific renewable MWa goal. The action plan includes implementation of the planned wind resources and new low-cost renewable resources that would be cost-effective. PacifiCorp recognizes that if a renewable resource comes within 10 percent of the cost of alternative resources when a decision is being made, the company would consider that resource to learn more about how to integrate that renewable technology into the system. This 10 percent is not an automatic adder to the price the company will pay for renewable resources.

The company included an item in the action plan regarding monitoring global climate science. PacifiCorp continues to maintain it has little to add to the ongoing scientific debate regarding anthropogenic contributions to global warming. Instead, the company can provide useful data on offsetting emissions at low cost. Pilot project efforts continue to help answer questions regarding project implementation and offset costs. Tracking scientific findings is nonetheless important to the company. Trexler and Associates are assisting the company in its efforts to track the latest scientific findings and policy changes, both domestically and internationally. Dr. Trexler, who is a well known and respected expert in the area of climate change mitigation, attends most of the international meetings on the science and policy of global warming, and he tracks the meetings he does not attend. Dr. Trexler provides to PacifiCorp reviews of the latest scientific findings, such as an assessment of the findings of the Intergovernmental Panel on Climate Change (IPCC).

Coal Resources

In RAMPP-3, new coal-fired resources were the least-cost supply-side resource choice. Since then natural gas prices have fallen substantially, making gas-fired resources cheaper than coal-fired resources. New coal-fired resources in RAMPP-4 cost between 31 and 38 mills/kWh; new gas-fired resources cost between 23 and 31 mills/kWh. Therefore, the RAMPP-4 modeling selected gas-fired resources to meet baseload needs. The model did not select coal-fired resources in any of the 37 cases. The shift from coal to gas has an additional advantage other than cost savings: gas-fired resources produce fewer emissions than coal, and thus expose the company to less risk from an environmental tax. Another advantage of gas-fired versus coal-fired resources is their diversification of PacifiCorp's resource mix (now heavily coal-based). Gas-fired resources also have a shorter lead time and lower initial capital outlay requirements. The major disadvantage of gas-fired resources is the uncertainty of future gas prices.

Despite the RAMPP-4 modeling results, the action plan includes a recommendation on coal. It calls for the company to evaluate clean coal technologies. PacifiCorp recognizes the potential fuel price risk for gas-fired resources, the availability of captive (non-price escalating) coal for future projects, and the technology improvements that might help reduce emissions at coal-fired plants. The company plans to watch these developments and position itself well in the event gas prices change or improved coal technology makes new coal-fired resources more attractive.

Other Opportunities

The RAMPP-4 action plan calls for the company to seek and pursue cost-effective opportunities that meet its future needs. By definition, the items anticipated by the "other opportunities" section are opportunities the company cannot predict. Therefore, RAMPP modeling cannot include such opportunities in the portfolio. They occur quickly and are now unknown. An opportunity to acquire resources could develop which the action plan does not specifically identify, but would be beneficial to the system and to the company's customers. PacifiCorp will watch for such opportunities and evaluate their costs and benefits as appropriate. The company looks for conditions that create opportunities to make transactions at discounted prices, such as other utilities in financial trouble. Typically, the company cannot postpone a decision on such an opportunity, or the chance for a successful transaction is lost. Evaluation of any such opportunity will use RAMPP-4 results along with other evaluation criteria.

Competitive Activity

The RAMPP-4 action plan states that the company will continue to be a low-cost provider of electricity and a successful competitor. The company believes that it will have to be a leader in the marketplace and keep its costs low in order to provide low-cost service to customers. RAMPP modeling could not capture the potential benefits of such a strategy, but an increasingly competitive environment demands it.

Improve the RAMPP Process

Improvements to the IRP process in each of the RAMPP cycles have made a demonstrable difference in the quality of the resulting report. The improvements have included adopting a linear programming optimization model, extending the analysis of externality costs by using a system approach, allowing the model to select the amount of DSM rather than forcing it, and adding summer peak capability to a winter peak model. The company looks forward to continually improving the RAMPP process.

The action plan contains four items to improve the IRP process:

a) Implement feasible process improvements identified in the RAMPP-4 regulatory acknowledgment review.

b) Evaluate other IRP models to assess the relative benefits of code improvements to IPM versus a different model to achieve the goals of RAMPP-5,

c) Evaluate the implication of the FERC NOPR for resource planning and implement appropriate changes to RAMPP modeling, and

d) Work with regulatory agencies and other parties to modify IRP to make the process more valuable to utilities and their customers.

Comments on the draft report raised some of the issues that will probably arise through the RAMPP-4 acknowledgment process. These included risk analysis and option analysis. Topics raised related to risk analysis included the risk of the wholesale part of the business versus retail and the relationship between the two, long-term versus short-term contracts, the amount of market resources relied upon, whether adequate transmission capacity will be available, the possibility of either a large load loss or a large load gain, and a gas price shock after building or acquiring significant amounts of gas-fired resources. Option analysis involves evaluating the cost of paying for an option on a resource so that it will be there when needed. The company believes all of these warrant consideration in the planning for RAMPP-5. At the first public advisory group meeting for RAMPP-5, the company plans on raising for discussion these and other issues developed in the RAMPP-4 acknowledgment process.

The company plans on exploring whether there are any other models on the market which would provide greater benefits than the current IPM model, and whether any code enhancements to the IPM model would be worthwhile.

The third item under the IRP improvement action item relates to transmission. Improvements in transmission modeling since RAMPP-1 include multi-area representation of the system including transmission constraints between areas, nomogram modeling, on- and off-peak transmission capability, and supply-side resource transmission integration costs. There are several possible ways to improve transmission modeling in RAMPP-5.

The IPM model provides a good technique for determining when increasing transmission capability would be cost-effective. This is the geographic conversion option discussed in Chapter 4. Another approach would be a major code change that allowed the model to select transmission instead of a supply-side resource. The model vendors would have to implement this code change. Past code changes required extensive time to implement for both the model vendor and PacifiCorp. Any code change may create unanticipated code problems that require considerable work to resolve. PacifiCorp believes the RAMPP process would benefit more from staff time spent on refining other matters. The existing model code already provides techniques to improve the analysis of transmission issues and to identify when additional transmission would be a cost-effective choice.

The size of the non-firm market in each geographic area will also require re-evaluation for RAMPP-5. RAMPP-5 may include more sensitivities varying market size and prices. Increasing the number of geographic areas and refining the capability of the transmission paths among them is an excellent way to improve the model's ability to analyze transmission issues. The transmission path west of the Bridger plant and the Idaho area may warrant more detailed definition in future RAMPP cycles. Another area that warrants more refinement is the California market. One possible approach is to divide it into two areas, which would allow a better representation of off-peak transmission capability. Increasing the number of geographic areas in California would allow a better portrayal of the constraints in moving power to, from, and within California. The company will discuss all of these approaches with the public advisory group in the RAMPP-5 process.

Nomograms are simultaneous capacity constraints on two paths. RAMPP-4 modeling may not have adequately portrayed all of the nomograms on the system. RAMPP-5 can refine the representation of nomograms.

On-peak and off-peak transmission constraints usually vary for each path. The company will perform detailed evaluation of the constraints on each path and how they vary during the day. This work may help the model better represent the system in RAMPP-5.

Additionally, RAMPP-5 will provide an opportunity to explore how restructuring in the industry and how the company's activities beyond the WSCC may have an impact on planning. The next two years will be important for the future of the company and the industry. The changes occurring will have impacts on planning that RAMPP-5 will be able to consider.

The last item deals with how the IRP process may evolve as the industry changes. The company believes it will be worthwhile to work with regulatory agencies and other parties to modify IRP to make the process more valuable to utilities and their customers. Rather than filing, in a formal process, for changes to the rules and guidelines of each Commission, the company believes it would be more productive to work with staff at each of the Commissions to explore how IRP should evolve.

DSM Action Plan Detail

The DSM Technical Appendix includes technical details of the RAMPP-4 DSM action plan. It is available in electronic format and upon request in paper format.

The RAMPP-4 action plan for DSM calls for achieving a total of 76 MWa of cost-effective reductions during 1996, 1997, and 1998. All goals have 10 percent transmission and distribution losses included. Therefore, the 76 MWa goal at the generation site is equal to 68 MWa at the customer site.

The DSM action plan detailed below is from case #13. This case used DSM costs reduced by 15 percent for the regional credit and for T&D investment credit.

For further details on the DSM selected by the model, see Tables 48-64 in the DSM technical appendix. The DSM technical appendix tables also show the timing and acquisition levels for all of the cases in the RAMPP-4 analysis, as well as information on all of the resource bundles.

In the past the company expressed program goals in MWa only. A peak demand DSM goal is new to the company's RAMPP planning process, but will be expanded in future planning. The RAMPP-4 goal for 1996-1998 of 76 MWa is equal to 132 MW of winter peak and 110 MW of summer peak savings. The DSM demand goals will allow comparisons of actual MW reductions. Table 6-7 shows the targets in energy (MWa), winter peak, and summer peak. Table 6-8 shows the cumulative amounts of DSM by 1998 by segment.

DSM Acquisition Targets 1996-1998

Table 6-7

	1996	1997	1998	Total
Average MW	23.0	25.0	28.0	76.0
Winter MW	39.0	43.0	50.0	132.0
Summer MW	33.0	35.0	41.0	109.0

1998 Cumulative DSM Targets by Segment

Table 6-8

Market	Energy MWa	Summer Peak MW	Winter Peak MW
Commercial New Construction	16.3	25.0	58.0
Commercial Existing	15.4	25.0	32.0
Industrial (new & existing)	36.0	37.0	37.0
Irrigation	0.8	0.0	2.0
Residential New Construction	0.4	0.8	0.2
Residential Existing	6.5	18.0	18.0
Total for all markets	75.4	105.8	147.2

The existing Energy FinAnswer program for new commercial customers will continue. The measure funding limits will be lowered to reflect the RAMPP-4 cost-effectiveness threshold of 40 Mills/kWh. The program will allow financing for peak load reduction measures. Table 6-9 shows the commercial new construction targets by state. The penetration rate for the commercial new construction market is assumed to be 75 percent in 1996 and 85 percent in 1997-1998. These penetration rates were applied to the forecasted square footage shown in Table 6-10.

Commercial retrofit will build upon PacifiCorp's current program experience in Oregon. The program will offer services and install measures with a cost-effectiveness limit of 29 mills/kWh. Only the first three bundles were cost-effective. Program expansion to other states will be in stages. By 1998 the program could be offered in all states with a combined three-year acquisition target of 15.4 MWa. Table 6-11 shows the Energy FinAnswer targets by state.

Industrial programs will build on the current industrial programs and will offer cost-effective energy services and incentives to industrial customers. In the RAMPP-4 analysis, the model selected the first four bundles of industrial DSM. The cut-off for each bundle is as follows: 13 mills/kWh for bundle one, 21 mills/kWh for bundle two, 23 mills/kWh for bundle three, and 27 mills/kWh for bundle four.

The Industrial programs will be a cornerstone of DSM acquisition for the 1996 to 1998 period. Over the next three years the company plans to acquire up to 36 MWa of DSM from this market, which is over half of the total expected savings. Due to the non-homogeneous nature of this market, savings amounts will be uneven over the three-year period. The year-by-year and state-by-state targets serve only as a guideposts. Measurement of the performance of this program will use its combined achievement of 36 MWa by the end of 1998. Table 6-12 shows the industrial targets by state.

The company's irrigation retrofit program was modified in 1994-1995 and is undergoing more changes. Table 6-13 shows the irrigation retrofit targets by state.

Commercial New Construction DSM Targets in MWa

Table 6-9

State	1996	1997	1998	Total
Oregon	1.5	2.1	2.3	5.9
Washington	0.3	0.3	0.3	0.9
Montana	0.4	0.5	0.4	1.3
California	0.1	0.1	0.2	0.4
Utah	1.8	2.0	2.3	6.2
Idaho UPL	0.0	0.1	0.1	0.1
Wyoming	0.4	0.4	0.5	1.4
Total	4.5	5.5	6.1	16.2

New Commercial Floor Space Additions (1000 sf)

Table 6-10

State	1996	1997	1998
Oregon	6,619	6,878	7,538
California	247	207	371
Washington	1,024	1,014	1,155
Idaho PPL	1,110	1,039	1,110
Idaho UPL	146	143	151
Montana	399	415	351
Wyoming PPL	334	312	336
Wyoming UPL	202	184	212
Utah	2,878	2,726	3,076
Pacific Division	9,733	9,865	10,860
Utah Division	3,225	3,054	3,440
TOTAL	25,917	25,837	28,600

Energy FinAnswer Retrofit DSM Targets in MWa

Table 6-11

State	1996	1997	1998	Total
Oregon	1.43	1.43	2.81	5.66
Washington	0.47	0.47	0.96	1.89
Montana	0.00	0.13	0.13	0.26
California	0.00	0.10	0.18	0.28
Utah	1.66	1.66	1.66	4.99
Idaho UPL	0.00	0.19	0.25	0.44
Wyoming PPL	0.44	0.44	0.95	1.84
Wyoming UPL	0.02	0.02	0.03	0.07
Total	4.0	4.4	7.0	15.4

Industrial Programs DSM Target in MWa

Table 6-12

State	1996	1997	1998	Total
Oregon	2.6	2.6	2.6	8.0
Utah	4.3	4.3	4.3	13.0
Other States	5.0	5.0	5.0	15.0
Total	11.9	11.9	11.9	36.0

Irrigation Retrofit Programs DSM Targets in MWa

Table 6-13

State	1996	1997	1998	Total
Oregon	0.19	0.19	0.19	0.57
Washington	0.00	0.00	0.00	0.00
Montana	0.00	0.00	0.00	0.00
California	0.07	0.07	0.07	0.21
Utah	0.00	0.00	0.00	0.00
Idaho UPL	0.00	0.00	0.00	0.00
Wyoming PPL	0.00	0.00	0.00	0.00
Wyoming UPL	0.00	0.00	0.00	0.00
Total	0.26	0.26	0.26	0.78

Super Good Cents Program Targets in MWa

Table 6-14

State	1996	1997	1998	Total
Oregon	0.05	0.06	0.07	0.2
Washington	0.02	3.00	0.03	0.1
Montana	0.00	0.00	0.01	0.01
California	0.02	0.03	0.03	0.1
Utah	0.00	0.00	0.00	0.00
Idaho UPL	0.01	0.01	0.01	0.03
Wyoming PPL	0.00	0.00	0.00	0.00
Wyoming UPL	0.00	0.00	0.00	0.00
Total	0.10	3.10	0.15	0.44

The Super Good Cents program for residential new construction will capture the remaining cost-effective lost-opportunities in the residential new construction market. Table 6-14 shows the targets by state.

Technology transformation programs are active for refrigerators and horizontal axis washing machines. The Super Efficient Refrigerator Program is an existing program and will continue without major change. Table 6-15 shows the targets by state.

Horizontal-Axis Washing Machines is the second set of activities in the company's series of technology transformation initiatives. This program is not cost-effective. However, customers' water savings significantly reduce the total resource cost input to the model. In fact, water savings benefits exceed the cost of this measure. Consequently the IPM model selected this bundle under all scenarios and conditions. PacifiCorp will continue working with national and regional groups to increase the market share for horizontal axis washing machines: Consortium for Energy Efficiency, City of Portland, and home manufacturers.

The company could use a variety of delivery mechanisms to increase market share for compact fluorescent lamps in the residential sector:

- Inclusion of compact fluorescent lamps in the water savings kits
- Direct installation (ECON type programs)
- Manufacturer promotions.

Table 6-16 shows the compact fluorescent targets by state.

The water savings measures program will build on the company's experience with existing water savings programs. The company will offer the program to untapped customer segments and service areas. Table 6-17 shows the water savings program targets by state.

Through the water savings and compact fluorescent lamps program the company will target residential new construction that may not be covered by the Super Good Cents program. The goal of this program is to increase market share for water savings measures and permanent compact fluorescent fixtures. Table 6-18 shows the water savings and compact fluorescent program targets by state.

RAMPP-4 analysis showed that the residential low income weatherization program is not cost-effective. However, the company

Technology Transformation Programs Targets in MWa
Super Efficient Refrigerator Program

Table 6-15

State	1996	1997	1998	Total
Oregon	0.02	0.02	0.03	0.10
Washington	0.00	0.01	0.01	0.01
Montana	0.00	0.00	0.00	0.00
California	0.00	0.00	0.00	0.01
Utah	0.03	0.03	0.03	0.10
Idaho UPL	0.00	0.00	0.00	0.01
Wyoming PPL	0.01	0.01	0.01	0.01
Wyoming UPL	0.00	0.00	0.00	0.00
Total	0.06	0.07	0.08	0.24

Compact Fluorescent Targets in MWa

Table 6-16

State	1996	1997	1998	Total
Oregon	0.29	0.29	0.28	0.90
Washington	0.07	0.07	0.07	0.20
Montana	0.02	0.02	0.02	0.10
California	0.02	0.02	0.02	0.10
Utah	0.34	0.34	0.34	1.00
Idaho UPL	0.03	0.03	0.03	0.10
Wyoming PPL	0.06	0.06	0.06	0.20
Wyoming UPL	0.01	0.01	0.01	0.00
Total	0.84	0.84	0.83	2.6

Water Saving Program Targets in MWa

Table 6-17

State	1996	1997	1998	Total
Oregon	0.08	0.07	0.06	0.20
Washington	0.21	0.20	0.18	0.60
Montana	0.05	0.04	0.04	0.10
California	0.07	0.07	0.06	0.20
Utah	0.21	0.19	0.17	0.60
Idaho UPL	0.07	0.07	0.06	0.20
Wyoming PPL	0.07	0.07	0.06	0.20
Wyoming UPL	0.01	0.01	0.01	0.03
Total	0.77	0.72	0.64	2.13

Water Saving and Compact Fluoresscent Targets in MWa

Table 6-18

State	1996	1997	1998	Total
Oregon	0.04	0.06	0.07	0.20
Washington	0.11	0.15	0.19	0.40
Montana	0.03	0.04	0.05	0.10
California	0.07	0.10	0.13	0.30
Utah	0.06	0.08	0.09	0.20
Idaho UPL	0.03	0.04	0.05	0.10
Wyoming PPL	0.05	0.06	0.08	0.20
Wyoming UPL	0.01	0.01	0.01	0.00
Total	0.40	0.54	0.67	1.50

will continue with this program and evaluate it to identify modifications to make it more cost-effective. The company anticipates improving the program's cost-effectiveness by implementing an audit-based incentive rather than incentives based on prescribed measures.

RAMPP-4 analysis showed the need to add peaking generation by 2002. The company believes that DSM can provide part of this capacity requirement. Table 6-19 shows a list of the initiatives that the company plans to evaluate, pilot, or implement during the 1996 to 1998 period to reduce the peak needs.

Currently the measure funding limits for many of the tariffed programs do not include an allowance for demand savings. Those programs that allow for demand savings do so in terms of a fixed $/kW, regardless of timing of the demand savings. The company plans to change the funding limit mechanism to value savings on a $/kW basis to the extent that is cost-effective.

During the 1995 to 1998 period, the company will be performing impact and process evaluations of its current programs. The mid-course correction for the relevant programs will incorporate findings from these evaluations.

The ESc can reduce utility costs by recovering more of the program costs directly from program participants. The company will continue to offer energy efficiency measure funding through an energy service charge on the customer bill. Where feasible, ancillary costs related to measure installation, such as design costs, engineering services, commissioning services, metering, and other energy-saving services will be added to the energy service charge or charged directly to the participant.

During 1996 to 1998 the company will broaden the ESc concept to include recovery of more of the costs of DSM activities from the customers who directly benefit from those efficiency improvements.

Peak Load Management Initiatives

Table 6-19

Industrial Market	Commercial Market	Residential Market
Direct Load Control (EMS)	Direct Load Control (EMS)	Direct Load Control
On-site Generation	On-site Generation	Water Heaters
Customer Load Control *(Demand limiting EMS)*	Customer Load Control *(Demand Limiting EMS)*	Air Conditioners
		Space Heat
Electrical system improvement	Pulse Meter Service and EMS	Heat Pump Smart Control
Thermal Storage	Thermal Storage	DHW-A/C-SH Combined
		Indirect Load Control

Benchmarks

If load growth, gas prices, the wholesale market, government actions, and the industry remained as they are today, PacifiCorp would only pursue DSM activities in the next two or three years. However, PacifiCorp can best serve its customers and the public interest by recognizing that resource needs change over time as changes occur in loads, gas prices, gas contract provisions, economic conditions, project opportunities, the wholesale market, regulation and the industry as a whole. In addition, the timing of the company's needs can change, depending on what the company is doing to help customers and organizations meet their energy needs.

PacifiCorp recognizes that even in as short a time as three years conditions could change which would require a re-evaluation of the action plan goals. For example, if load growth for the next two years were to suddenly move to the medium-high level, and the company were convinced it would stay at that level, then a new gas-fired baseload resource could be needed by the year 2000, requiring a decision in 1996. Therefore, these benchmarks are important guideposts for the company to monitor.

Conditions that could justify less DSM include lower load growth or lower gas prices than expected. Conditions that could justify more DSM include higher load growth, higher gas prices, or more costly environmental controls than expected. Conditions that could justify fewer summer peak purchases include lower load growth, lower gas prices or higher gas prices, higher non-firm market prices, or more costly environmental controls. The company might need more summer peak purchases if there is higher load growth. Lower load growth, higher gas prices, lower cost of renewables, or lower non-firm market prices could result in less need for gas-fired resources. Higher load growth, lower gas prices, higher non-firm prices, or more costly environmental controls could result in more need for gas-fired resources.

If any of these changes occurs, the company will re-examine its RAMPP-4 action plan. Following is a list of benchmarks the company will monitor. If any of these is triggered, the company will need to re-examine the entire RAMPP-4 action plan:

- **Load growth for 1995 is below 1.5 percent for the system as a whole or for one geographic area of the system.**
  The medium-low load growth rate was about 1 percent, but a small percentage change can have a dramatic effect on resource needs. The company believes a significant change would be load growth falling to half-way between the medium and the medium-low growth rates.

- **Load growth for 1995 is above 2.5 percent for the system as a whole or for one geographic area of the system.**
  The medium-high load growth amount was about 3 percent, the company believes growth of 2.5 percent could have a significant change on resource needs.

- **Accepted gas price forecasts indicate prices will rise by 0 percent real escalation or less.**
  Zero percent real escalation was the rate used in the low gas price cases. The company believes it represents a likely level for gas price change that could have a large enough impact on the costs of new gas-fired resources to warrant a re-examination.

- **Accepted gas price forecasts indicate prices will rise by 4 percent real escalation or higher.**
  Four percent real escalation was about the rate used in the high gas price cases. As with the low rate, it would be large enough to impact the costs of new gas-fired resources.

- **Non-firm market prices fall by 25 percent or more from their 1995 levels.**
  The modeling used a 25 percent decline in non-firm prices as the low case and for this benchmark because the company believes it constitutes a significant change in the non-firm market.

- **Non-firm market prices increase by 25 percent or more from their 1995 levels.**
  The modeling used a 25 percent increase in non-firm prices as its high case and for this benchmark, again because it would be a significant change in the non-firm market.

- **The federal government passes some form of CO2 emissions controls or tax.**

- **One of the renewable technologies achieves costs that are within 10 percent of the cost of acquiring gas-fired resources at the time a decision would be made.**

While the company is monitoring trends against these benchmarks, the public advisory group will be meeting in the summer of 1996 to begin working on RAMPP-5. PacifiCorp will have the opportunity to review the benchmarks with the public advisory group and maintain a dialogue on the impact of benchmark trends on the RAMPP-4 action plan. At this point the company cannot describe what actions might be taken under each benchmark change. Any change in one benchmark could be accompanied by any change in any other benchmark. The company will always be responding to a unique set of circumstances.

Conclusion

PacifiCorp recognizes that 1995 is a transition year. The industry is changing and integrated resource planning must change with it. Several trends are converging:

- FERC actions to open the transmission system,
- Deregulation and/or alternative forms of regulation on the state level,
- Greater access to wholesale power from existing plants in other geographic areas,
- Greater competition in the wholesale markets,
- Movement toward retail wheeling or similar opportunities for large customers to choose their energy supplier, and
- Developers building power plants and selling to all buyers.

Given the pace and degree of change, utilities are well advised to avoid commitments that could cause price increases. This is a time to find opportunities to provide more choices and more services to customers at competitive prices. PacifiCorp looks forward to achieving that goal and to being the energy supplier of choice for its customers.

Index

FLEXIBLE CHOICES FOR A CHANGING MARKET

Resource and Market Planning Program
RAMPP - 4

APPENDIX: INPUTS AND RESULTS

NOVEMBER, 1995

PACIFICORP

PacifiCorp
RAMPP-4
Appendix: Inputs and Results

Table of Contents

PacifiCorp
RAMPP-4
Appendix: Inputs and Results

Table of Contents

Chapter 1:

RAMPP-3 to RAMPP-4 Comparisons

RAMPP-3 to RAMPP-4 Comparisons
Energy and Peak Loads

		OWC						Utah						Wyoming						Total System					
IPM Run Year			Win Peak		Sum Peak		S/W		Win Peak		Sum Peak		S/W		Win Peak		Sum Peak		S/W		Win Peak		Sum Peak		S/W
		MWA	MW	LF	MW	LF	Ratio	MWA	MW	LF	MW	LF	Ratio	MWA	MW	LF	MW	LF	Ratio	MWA	MW	LF	MW	LF	Ratio
1996	YES	2451	4008	61.2%	3100	79.1%	0.77	2113	2604	81.1%	3239	65.2%	1.24	850	957	88.8%	930	91.4%	0.97	5414	7569	71.5%	7269	74.5%	0.96
1997	YES	2498	4097	61.0%	3133	79.7%	0.76	2157	2670	80.8%	3405	63.4%	1.28	762	864	88.2%	778	97.9%	0.90	5417	7631	71.0%	7316	74.0%	0.96
1998	YES	2537	4162	61.0%	3177	79.9%	0.76	2201	2727	80.7%	3482	63.2%	1.28	746	847	88.0%	798	93.5%	0.94	5484	7736	70.9%	7457	73.5%	0.96
1999	YES	2586	4242	61.0%	3210	80.6%	0.76	2247	2786	80.6%	3580	62.8%	1.28	763	866	88.1%	833	91.5%	0.96	5595	7894	70.9%	7623	73.4%	0.97
2000	YES	2653	4339	61.2%	3356	79.1%	0.77	2310	2858	80.8%	3666	63.0%	1.28	785	888	88.4%	838	93.6%	0.94	5748	8085	71.1%	7860	73.1%	0.97
2001	YES	2706	4438	61.0%	3389	79.8%	0.76	2359	2926	80.6%	3744	63.0%	1.28	806	915	88.1%	862	93.5%	0.94	5870	8279	70.9%	7995	73.4%	0.97
2002	YES	2765	4536	61.0%	3482	79.4%	0.77	2417	2999	80.6%	3836	63.0%	1.28	831	943	88.1%	889	93.5%	0.94	6013	8478	70.9%	8207	73.3%	0.97
2003	YES	2830	4643	61.0%	3517	80.5%	0.76	2482	3079	80.6%	3962	62.6%	1.29	856	972	88.1%	934	91.7%	0.96	6168	8694	70.9%	8413	73.3%	0.97
2004	NO	2905	4751	61.1%	3676	79.0%	0.77	2556	3163	80.8%	4054	63.1%	1.28	886	1003	88.4%	940	94.3%	0.94	6348	8917	71.2%	8670	73.2%	0.97
2005	YES	2954	4847	61.0%	3703	79.8%	0.76	2605	3232	80.6%	4138	63.0%	1.28	903	1025	88.1%	966	93.5%	0.94	6463	9104	71.0%	8807	73.4%	0.97
2006	NO	3011	4940	61.0%	3775	79.8%	0.76	2660	3300	80.6%	4223	63.0%	1.28	926	1050	88.2%	988	93.7%	0.94	6598	9290	71.0%	8986	73.4%	0.97
2007	NO	3079	5051	61.0%	3860	79.8%	0.76	2720	3375	80.6%	4321	63.0%	1.28	947	1074	88.1%	1011	93.6%	0.94	6745	9500	71.0%	9192	73.4%	0.97
2008	YES	3159	5167	61.1%	3920	80.6%	0.76	2796	3461	80.8%	4425	63.2%	1.28	977	1104	88.5%	1028	95.0%	0.93	6932	9732	71.2%	9373	74.0%	0.96
2009	NO	3210	5266	61.0%	3986	80.5%	0.76	2850	3538	80.6%	4555	62.6%	1.29	996	1129	88.2%	1088	91.5%	0.96	7056	9933	71.0%	9629	73.3%	0.97
2010	NO	3271	5367	61.0%	4064	80.5%	0.76	2914	3617	80.6%	4656	62.6%	1.29	1018	1154	88.2%	1106	92.0%	0.96	7203	10138	71.1%	9826	73.3%	0.97
2011	YES	3334	5469	61.0%	4141	80.5%	0.76	2978	3697	80.6%	4758	62.6%	1.29	1039	1178	88.2%	1135	91.5%	0.96	7351	10344	71.1%	10034	73.3%	0.97
2012	NO	3406	5571	61.1%	4223	80.6%	0.76	3044	3769	80.8%	4856	62.7%	1.29	1063	1201	88.5%	1142	93.0%	0.95	7512	10541	71.3%	10221	73.5%	0.97
2013	NO	3452	5663	61.0%	4298	80.3%	0.76	3088	3834	80.5%	4931	62.6%	1.29	1078	1222	88.2%	1176	91.7%	0.96	7617	10719	71.1%	10405	73.2%	0.97
2014	NO	3498	5758	60.8%	4374	80.0%	0.76	3132	3900	80.3%	5008	62.5%	1.28	1093	1243	88.0%	1210	90.4%	0.97	7724	10901	70.9%	10592	72.9%	0.97
2015	YES	3545	5853	60.6%	4451	79.7%	0.76	3178	3967	80.1%	5086	62.5%	1.28	1109	1265	87.7%	1245	89.1%	0.98	7832	11085	70.7%	10782	72.6%	0.97
2016	NO	3545	5853	60.6%	4451	79.7%	0.76	3178	3967	80.1%	5086	62.5%	1.28	1109	1265	87.7%	1245	89.1%	0.98	7832	11085	70.7%	10782	72.6%	0.97
2024	YES	3545	5853	60.6%	4451	79.6%	0.76	3178	3967	80.1%	5086	62.5%	1.28	1109	1265	87.7%	1245	89.1%	0.98	7832	11085	70.7%	10782	72.6%	0.97
2038	YES	3545	5853	60.6%	4451	79.6%	0.76	3178	3967	80.1%	5086	62.5%	1.28	1109	1265	87.7%	1245	89.1%	0.98	7832	11085	70.7%	10782	72.6%	0.97

RAMPP-3 to RAMPP-4 Comparisons
Loads, Sales, Purchases

RAMPP-4			1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Annual Winter Peak Capacity (MW)																						
Native Load			7569	7631	7736	7894	8085	8279	8478	8694	8694	9104	9104	9104	9732	9732	9732	10344	10344	10344	10344	11085
Firm Sales			1463	1463	1463	1363	1313	1313	1313	1313	1313	995	995	995	737	737	737	612	612	612	612	437
Firm Purchases			963	825	830	824	799	774	769	761	761	319	319	319	269	269	269	269	269	269	269	269
Net Demand on System			8069	8269	8369	8433	8599	8818	9022	9246	9246	9780	9780	9780	10200	10200	10200	10687	10687	10687	10687	11253
Annual Summer Peak Capacity (MW)																						
Native Load			7269	7316	7457	7623	7860	7995	8207	8413	8413	8807	8807	8807	9373	9373	9373	10034	10034	10034	10034	10782
Firm Sales			1785	1900	1900	1875	1890	1795	1795	1795	1795	1485	1485	1485	1177	1177	1177	1102	1102	1102	1102	927
Firm Purchases			809	758	658	638	632	607	600	579	579	424	424	424	424	424	424	374	374	374	374	341
Net Demand on System			8245	8458	8699	8860	9118	9183	9402	9629	9629	9868	9868	9868	10126	10126	10126	10762	10762	10762	10762	11368
Cumulative Annual Energy (MWa)																						
Native Load			5414	5416	5484	5595	5747	5870	6012	6168	6168	6462	6462	6462	6931	6931	6931	7350	7350	7350	7350	7832
Firm Sales			1604	1621	1570	1532	1513	1488	1488	1453	1453	1264	1264	1264	1092	1092	1092	1037	1037	1037	1037	828
Firm Purchases			558	505	474	466	456	447	445	441	441	400	400	400	383	383	383	378	378	378	378	358
Net Demand on System			6460	6532	6580	6661	6804	6911	7055	7180	7180	7326	7326	7326	7640	7640	7640	8009	8009	8009	8009	8302
RAMPP-3	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	4011	2012	2013		
Annual Winter Peak Capacity (MW)																						
Native Load	7497	7681	7881	8067	8244	8427	8632	8842	8842	9273	9273	9273	9785	9785	9785	10389	10389	10389	10389	11206		
Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	1195	1195	1195	887	887	887	687	687	687	687	437		
Firm Purchases	980	1071	867	816	817	797	773	766	766	317	317	317	312	312	312	262	262	262	262	262		
Net Demand on System	7912	8005	8259	8496	8672	8875	9054	9271	9271	10151	10151	10151	10360	10360	10360	10814	10814	10814	10814	11381		
Cumulative Annual Energy (MWa)																						
Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6322	6634	6634	6634	6987	6987	6987	7411	7411	7411	7411	7998		
Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1434	1410	1410	1410	1220	1220	1220	1043	1043	1043	1043	841		
Firm Purchases	644	643	452	435	412	403	393	388	388	364	364	364	361	361	361	336	336	336	336	346		
Net Demand on System	6192	6321	6647	6779	6933	7098	7270	7368	7368	7680	7680	7680	7846	7846	7846	8118	8118	8118	8118	8493		
R4-R3 Win Sales			218	218	218	118	118	118	118	118	118	-200	108	108	-150	50	50	-75	-75	175		
R4-R3 Win Purchases			96	9	13	27	26	8	3	444	444	2	7	7	-43	7	7	7	7	7		
RAMPP-4 Sum - RAMPP-3 Win			-14	-38	27	-15	64	-88	131	-522	-522	-283	-492	-492	-234	-688	-688	-52	-52	-619		
Energy Difference			-187	-247	-353	-437	-466	-457	-313	-500	-500	-354	-520	-520	-206	-478	-478	-109	-109	-484		
RAMPP-4			1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	4011	2012	2013		
			8069	8269	8369	8433	8599	8818	9022	9246	9246	9780	9780	9780	10200	10200	10200	10687	10687	10687		
			8245	8458	8699	8860	9118	9183	9402	9629	9629	9868	9868	9868	10126	10126	10126	10762	10762	10762		
			8259	8496	8672	8875	9054	9271	9271	10151	10151	10151	10360	10360	10360	10814	10814	10814	10814	11381		

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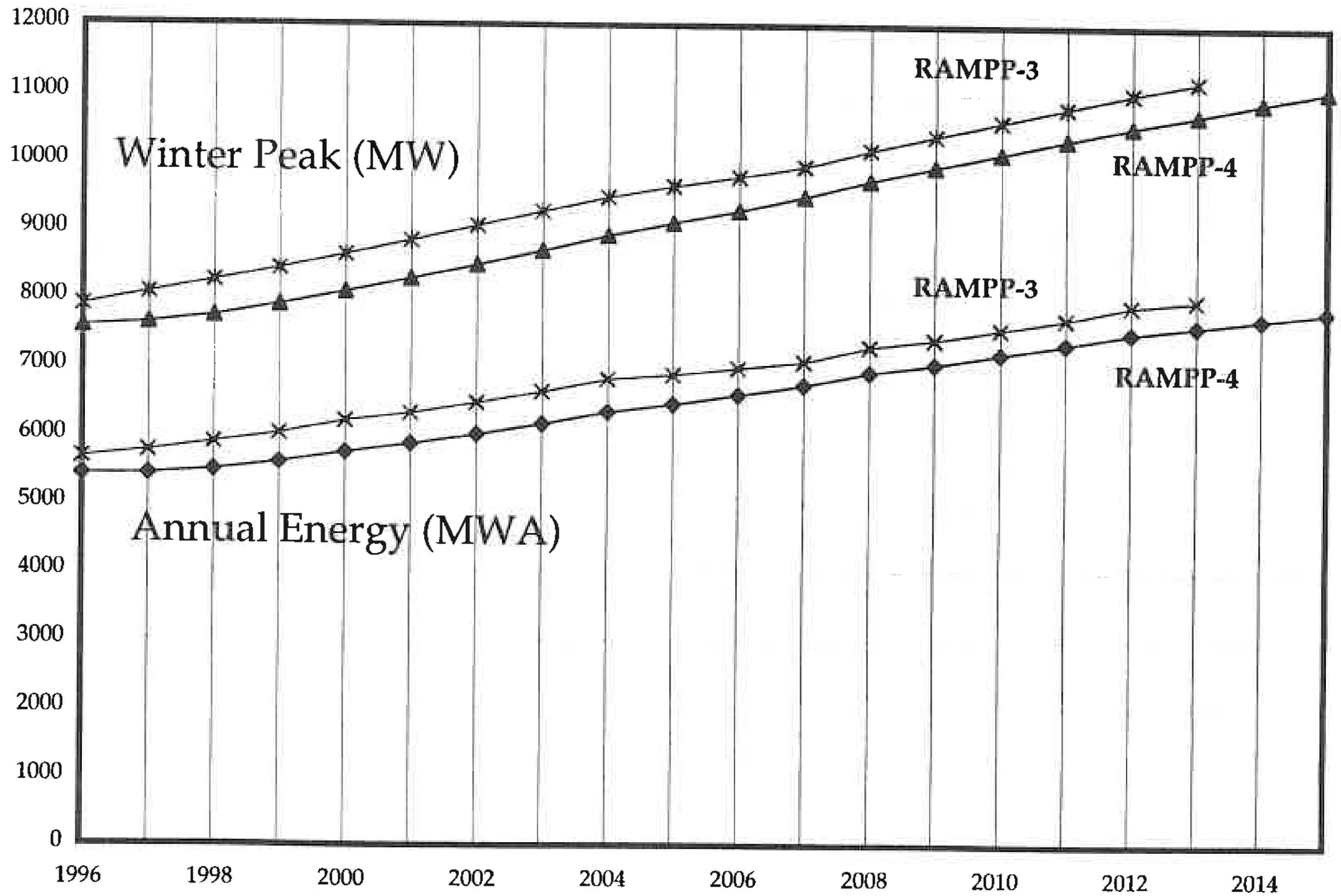
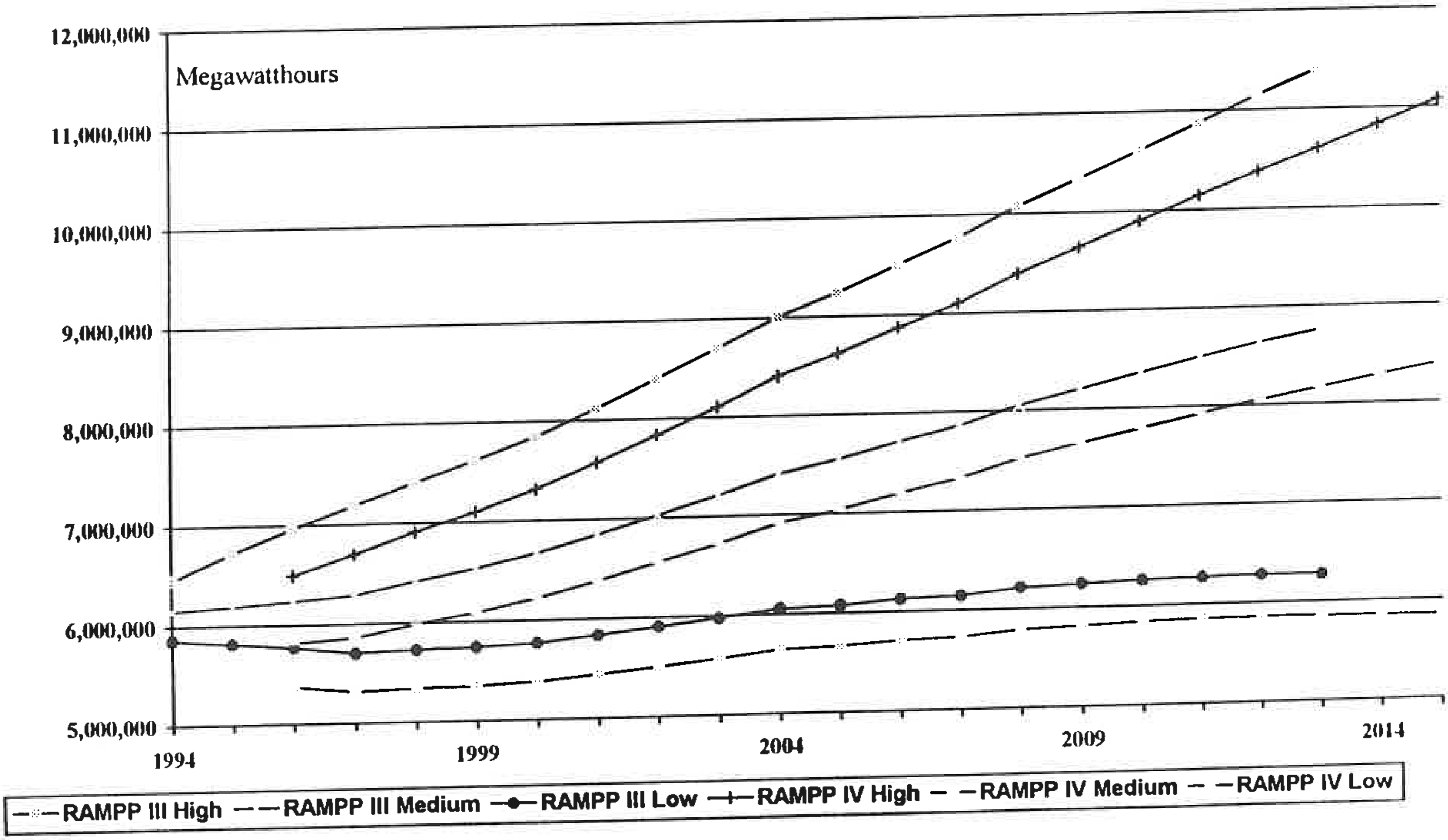
RAMPP-3 to RAMPP-4 Comparisons
Load Forecasts



PacifiCorp

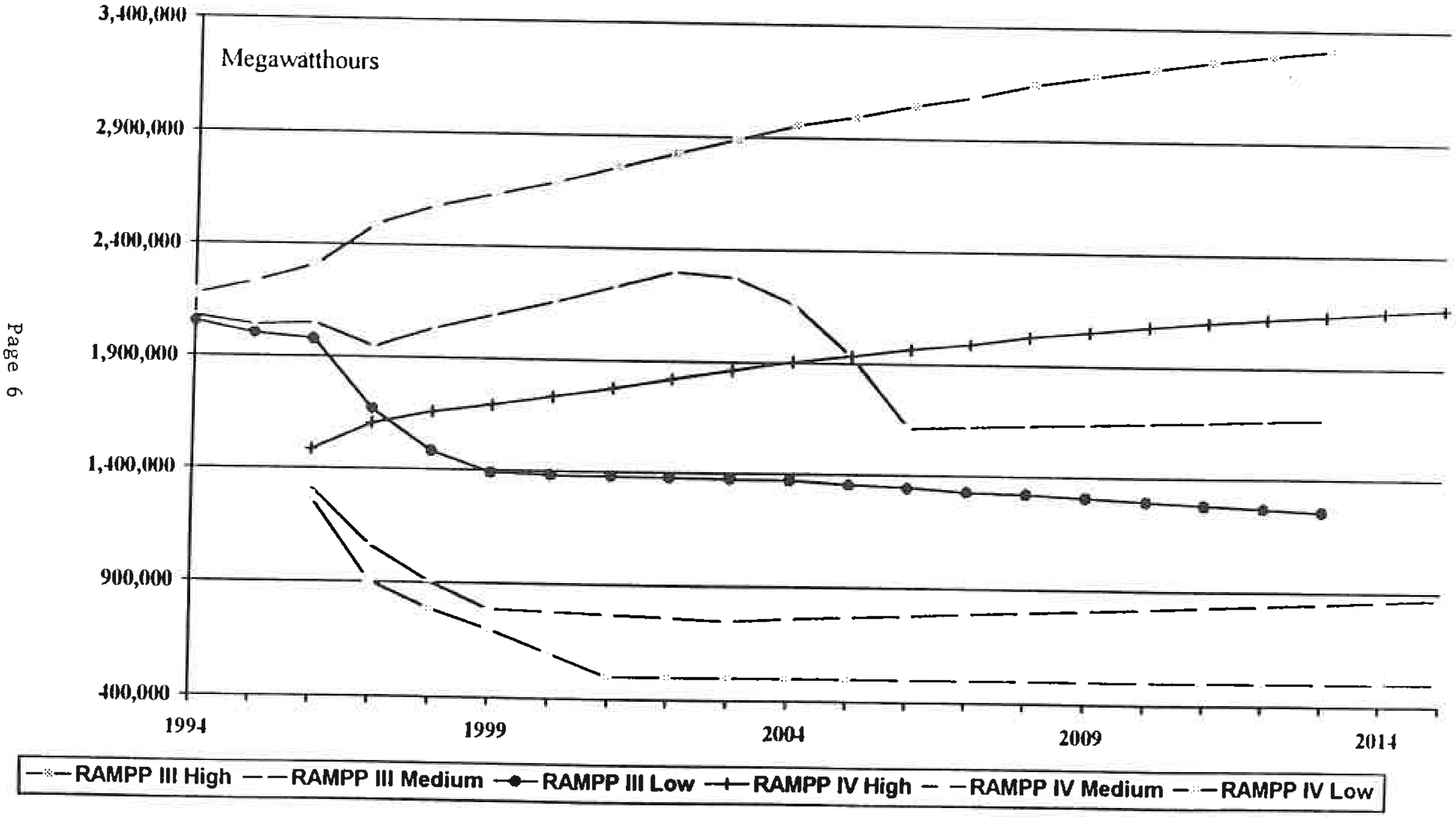
RAMPP-4

RAMPP-3 and RAMPP-4 Forecasts



EASTERN WYOMING

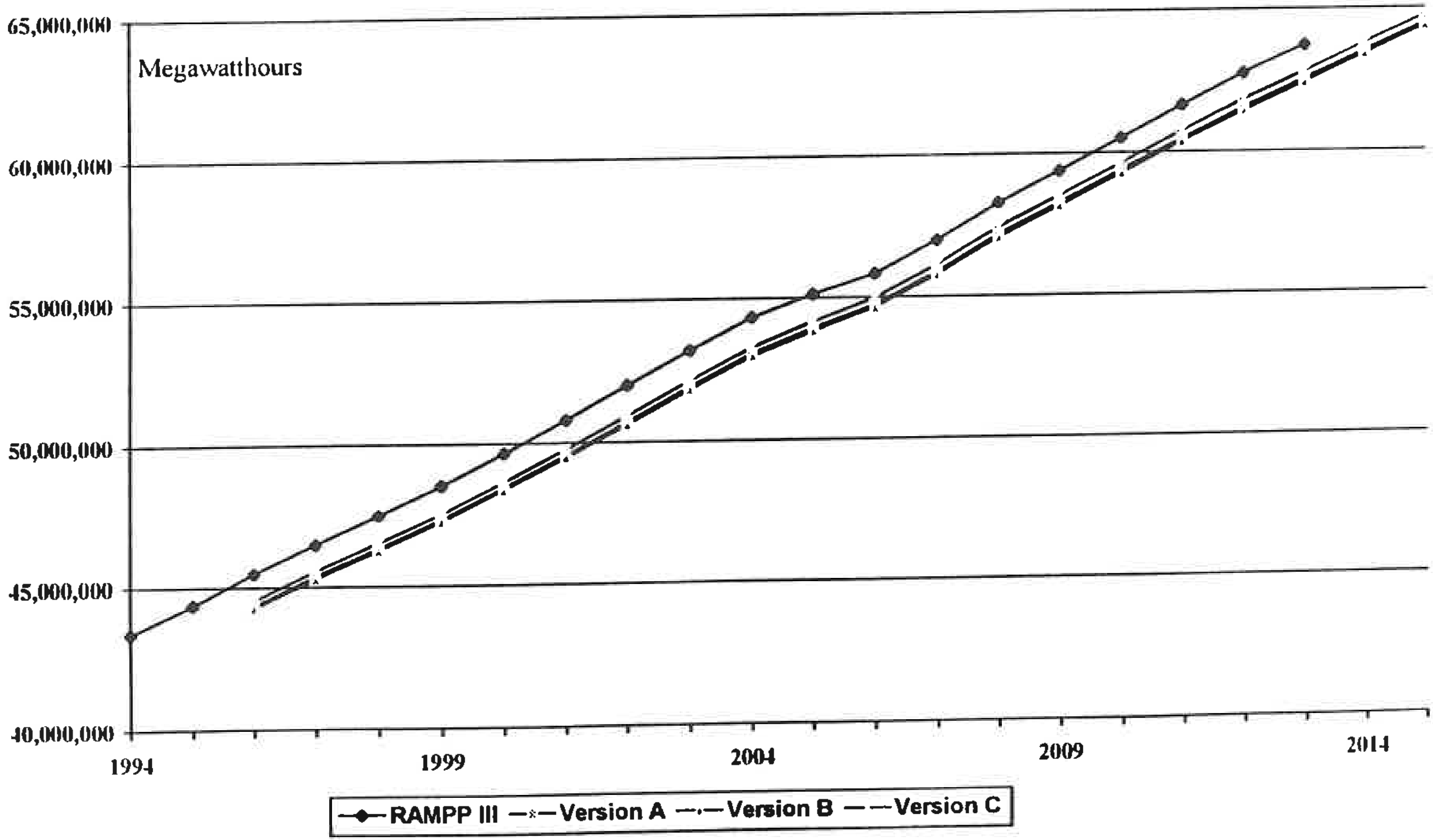
RAMPP-3 and RAMPP-4 Forecasts



WESTERN WYOMING

PacifiCorp

RAMPP-3 & Potential RAMPP-4 Forecasts

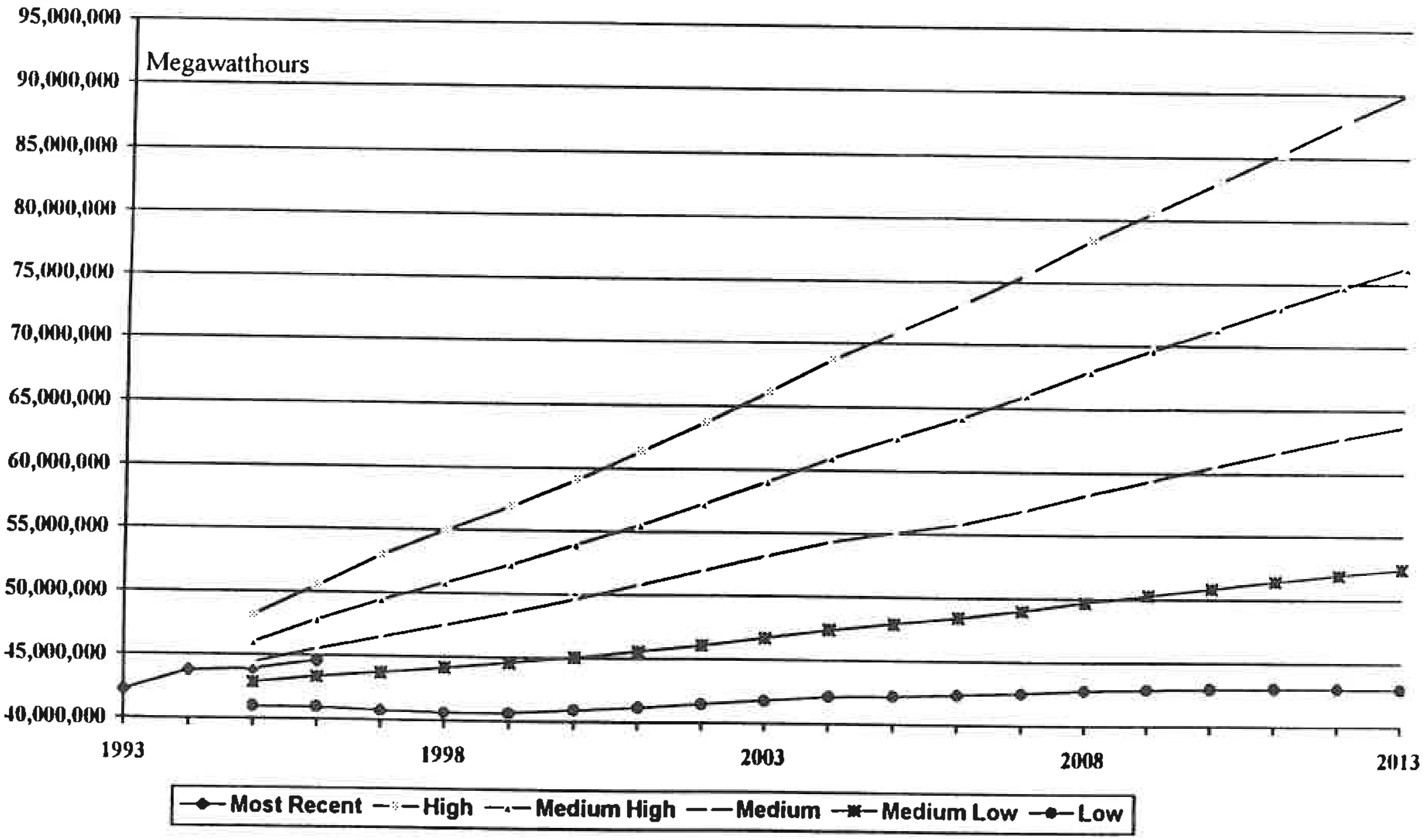


MEDIUM

PacifiCorp

RAMPP-4

RAMPP-3 & Most Recent Forecasts



TOTAL SALES

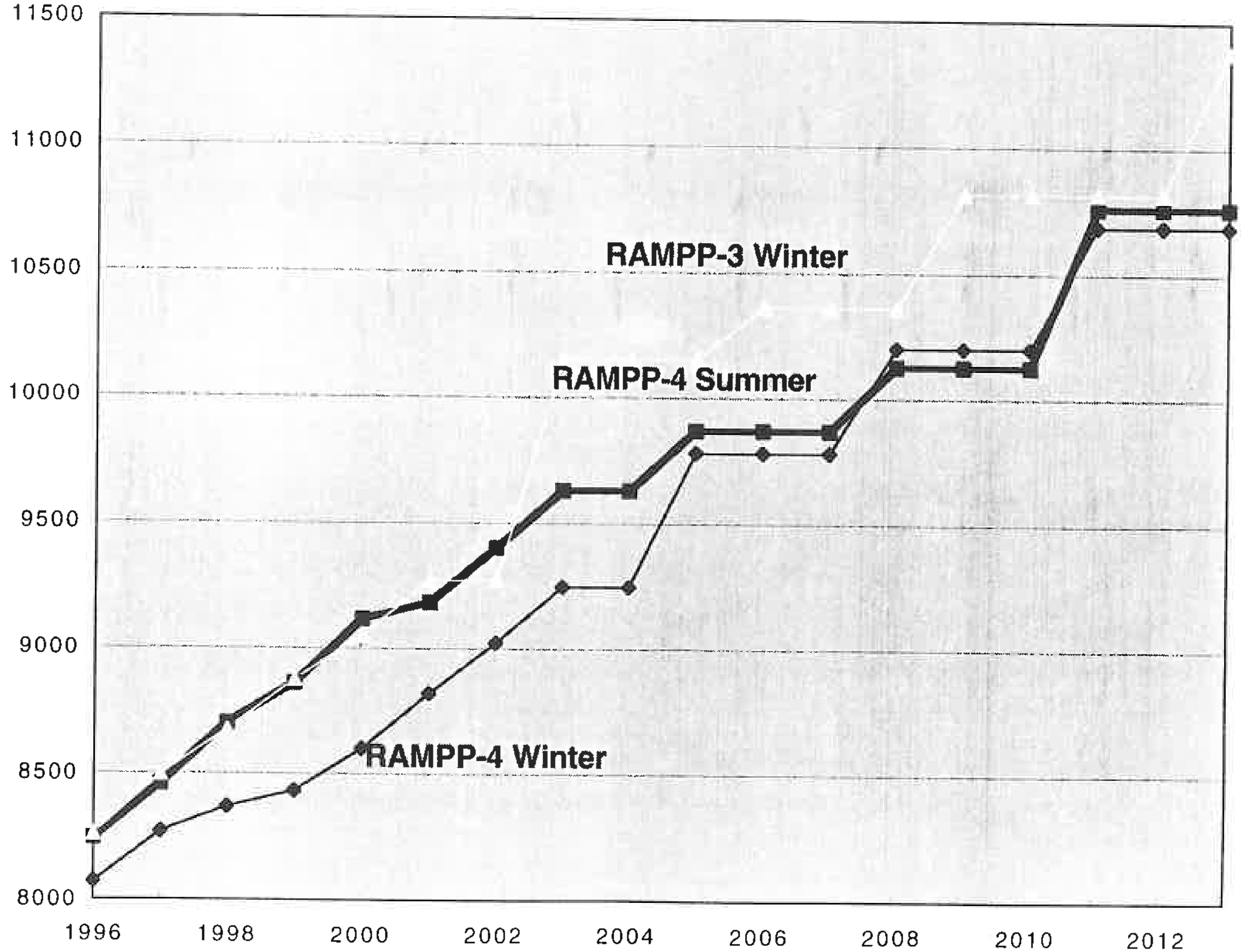
Page 8

Increase(Decrease) of RAMPP-4 Forecast over RAMPP-3 Forecast

Average Megawatts

Year	Oregon	Washington	Montana	E. Wyoming	N. Idaho	California	S. Idaho	Utah	W. Wyoming
1996	(15.39)	(5.13)	(0.18)	(62.04)	(33.61)	(1.21)	(1.73)	(16.35)	(94.97)
1997	(15.39)	(5.13)	(0.18)	(156.65)	(34.47)	(1.21)	(1.73)	(16.35)	(111.46)
1998	(15.39)	(5.13)	(0.18)	(192.22)	(34.97)	(1.21)	(1.73)	(16.35)	(139.33)
1999	(15.39)	(5.13)	(0.18)	(193.44)	(35.67)	(1.21)	(1.73)	(16.35)	(160.00)
2000	(15.39)	(5.13)	(0.18)	(195.05)	(36.71)	(1.21)	(1.73)	(16.35)	(169.57)
2001	(15.39)	(5.13)	(0.18)	(196.57)	(37.46)	(1.21)	(1.73)	(16.35)	(178.49)
2002	(15.39)	(5.13)	(0.18)	(198.38)	(38.30)	(1.21)	(1.73)	(16.35)	(187.99)
2003	(15.39)	(5.13)	(0.18)	(200.23)	(39.31)	(1.21)	(1.73)	(16.35)	(186.21)
2004	(15.39)	(5.13)	(0.18)	(202.41)	(40.52)	(1.21)	(1.73)	(16.35)	(171.97)
2005	(15.39)	(5.13)	(0.18)	(203.62)	(41.33)	(1.21)	(1.73)	(16.35)	(142.90)
2006	(15.39)	(5.13)	(0.18)	(205.28)	(42.29)	(1.21)	(1.73)	(16.35)	(102.70)
2007	(15.39)	(5.13)	(0.18)	(206.77)	(43.55)	(1.21)	(1.73)	(16.35)	(52.20)
2008	(15.39)	(5.13)	(0.18)	(208.95)	(44.96)	(1.21)	(1.73)	(16.35)	(56.65)
2009	(15.39)	(5.13)	(0.18)	(210.31)	(45.62)	(1.21)	(1.73)	(16.35)	(60.02)
2010	(15.39)	(5.13)	(0.18)	(211.91)	(46.58)	(1.21)	(1.73)	(16.35)	(63.81)
2011	(15.39)	(5.13)	(0.18)	(213.45)	(47.59)	(1.21)	(1.73)	(16.35)	(67.58)
2012	(15.39)	(5.13)	(0.18)	(215.16)	(48.90)	(1.21)	(1.73)	(16.35)	(71.70)
2013	(15.39)	(5.13)	(0.18)	(216.27)	(49.72)	(1.21)	(1.73)	(16.35)	(74.74)

RAMPP-3 to RAMPP-4 Comparisons
Sum of Load plus Sales less Purchases



RAMPP-3 to RAMPP-4 Comparisons
Coal Costs for Existing System

Year	Carbon	Centraia	Cholla	Colstrip	Craig	Johnston	Gadsby	Hayden	Huntgtn	Hunter	Bridger	Naugtn	Wyodak
	CAR	CEN	CHL	CLS	CRG	DJN	GDS	HAY	HTN	HTR	JBR	NAU	WYD
RAMPP-4													
1995	75.7	140.3	156.4	82.4	103.4	61.2	230.5	98.6	85.3	100.8	94.0	119.2	75.9
1996	78.2	144.9	161.6	85.1	106.8	63.2	238.1	101.9	88.1	104.1	97.1	123.1	78.4
1997	80.8	149.7	166.9	87.9	110.3	65.3	246.0	105.3	91.0	107.5	100.3	127.2	81.0
1998	83.4	154.6	172.4	90.8	114.0	67.4	254.1	108.7	94.0	111.1	103.6	131.4	83.7
1999	86.2	159.7	178.1	93.8	117.7	69.7	262.5	112.3	97.1	114.7	107.0	135.7	86.4
RAMPP-3													
1994	73.0	133.0	169.0	80.4	108.7	63.4	196.6	93.3	79.5	94.4	91.1	138.7	70.1
1995	75.0	132.1	174.9	83.8	112.5	64.2	203.6	97.0	81.7	105.1	94.4	143.0	72.4
1996	77.0	136.2	176.1	87.4	114.9	66.4	224.9	100.9	85.4	104.3	97.2	148.3	77.2
1997	79.0	139.8	183.4	90.9	119.7	67.0	248.9	104.5	87.9	106.4	100.7	152.3	77.0
1998	81.7	144.6	189.6	94.0	123.8	69.3	257.4	108.1	90.9	110.0	104.1	158.0	79.6
1999	84.5	149.5	196.1	97.2	128.0	71.6	266.1	111.7	94.0	113.8	107.7	164.0	82.3
Change													
1995	0.7	8.2	-18.5	-1.4	-9.1	-3.0	26.9	1.6	3.6	-4.3	-0.4	-23.8	3.5
1996	1.2	8.7	-14.5	-2.3	-8.1	-3.2	13.2	1.0	2.7	-0.2	-0.1	-25.2	1.2
1997	1.8	9.9	-16.5	-3.0	-9.4	-1.7	-2.9	0.8	3.1	1.1	-0.4	-25.1	4.0
1998	1.8	10.1	-17.2	-3.2	-9.8	-1.8	-3.3	0.7	3.1	1.1	-0.5	-26.7	4.0
1999	1.7	10.3	-18.0	-3.4	-10.3	-2.0	-3.7	0.6	3.1	1.0	-0.6	-28.3	4.1
Percent Change													
1995	1%	6%	-11%	-2%	-8%	-5%	13%	2%	4%	-4%	0%	-17%	5%
1996	2%	6%	-8%	-3%	-7%	-5%	6%	1%	3%	0%	0%	-17%	2%
1997	2%	7%	-9%	-3%	-8%	-3%	-1%	1%	4%	1%	0%	-17%	5%
1998	2%	7%	-9%	-3%	-8%	-3%	-1%	1%	3%	1%	0%	-17%	5%
1999	2%	7%	-9%	-3%	-8%	-3%	-1%	1%	3%	1%	-1%	-17%	5%

RAMPP-3 to RAMPP-4 Comparisons
Supply-Side Portfolio Energy Costs

Short Name	Description	RAMPP-4 Energy 1996$ 1st Year ¢/MMBTU	RAMPP-4 Levelized ¢/MMBTU	RAMPP-4 Levelized Mills/kWh	RAMPP-4 TRC Mills/kWh	RAMPP-3 Energy 1994$ 1st Year ¢/MMBTU	RAMPP-3 Levelized ¢/MMBTU	RAMPP-3 Levelized Mills/kWh	RAMPP-3 TRC Mills/kWh	Difference $1994 1st Year ¢/MMBTU	Difference Levelized ¢/MMBTU	Difference Levelized Mills/kWh	Difference TRC Mills/kWh
CPU	One Year Firm Purch	180.0	219.3	23.1	32.4	0.0	0.0	0.0	999.0	168.7	205.5	21.7	(999.0)
HRM	Hermiston	Modeled as an existing unit				193.6	293.3	20.8	33.2				
OC1	OWC Cogen 1	215.1	254.4	10.9	26.4	289.8	492.6	27.1	41.5	(88.2)	(254.2)	(16.8)	(16.7)
OC2	OWC Cogen 2	215.1	254.4	15.8	26.1	289.8	492.6	33.5	43.4	(88.2)	(254.2)	(18.7)	(18.9)
OCC	OWC Combined Cycle	215.1	254.4	18.2	29.8	289.8	492.6	35.3	47.2	(88.2)	(254.2)	(18.2)	(19.3)
OCT	OWC Simple Cycle CT	180.0	219.3	23.1	91.2	255.8	458.6	48.4	249.7	(87.1)	(253.1)	(26.7)	(164.2)
OGT	OWC Geothermal	107.3	107.3	10.7	41.7	220.4	415.0	41.5	74.8	(119.8)	(314.4)	(31.4)	(35.7)
OPS	OWC Pump Storage	0.0	0.0	0.0	32.1	0.0	0.0	0.0	50.1	0.0	0.0	0.0	(20.0)
OW1	OWC Wind Non-Firm	0.0	0.0	0.0	49.2	Comparable to OWC Wind w Tax C				(126.1)	(152.2)	(15.2)	(14.3)
OW2	OWC Wind Firm	0.0	0.0	0.0	57.0	Not Modeled in RAMPP-3							
OW1	OWC Wind w Tax C	Comparable to OWC Wind Non-Firm				126.1	152.2	15.2	60.4	(126.1)	(152.2)	(15.2)	(14.3)
OW2	OWC Wind w/o Tax C	Comparable to OWC Wind Non-Firm				126.1	152.2	15.2	73.0	(126.1)	(152.2)	(15.2)	(5.8)
UC1	Utah Cogen 1	189.3	228.6	9.8	27.8	264.8	475.0	26.1	42.8	(87.4)	(260.8)	(16.9)	(16.8)
UC2	Utah Cogen 2	189.3	228.6	14.2	26.1	264.8	475.0	32.3	43.6	(87.4)	(260.8)	(19.0)	(19.1)
UCC	Utah Combined Cycle	189.3	228.6	16.4	29.6	264.8	475.0	34.0	46.7	(87.4)	(260.8)	(18.7)	(18.9)
UCT	Utah Simple Cycle CT	173.8	213.1	22.5	87.5	269.8	480.0	50.6	228.3	(106.9)	(280.3)	(29.5)	(146.2)
UCY	Utah IGCC Hunter 4	89.0	98.5	7.9	35.7	Comparable to Utah IGCC CT				31.2	40.1	2.9	1.0
UCZ	Utah IGCC CT	103.5	114.5	9.1	38.0	52.2	52.2	4.5	32.5	44.8	55.1	4.1	3.1
UD1	Utah Gadsby Repower	189.3	228.6	17.1	24.2	Not Modeled in RAMPP-3							
UFB	Utah FB Coal	Not Modeled in RAMPP-4				52.2	52.2	4.8	35.1				
UG1	Utah PC Hunter 4 $20/Ton	89.0	98.5	9.4	31.5	Comparable to Utah Coal				31.2	40.1	3.6	1.4
UG2	Utah Coal $23.25/Ton	103.5	114.5	11.0	36.3	Comparable to Utah Coal				44.8	55.1	5.1	5.9
UG3	Utah Coal $27.00/Ton	120.2	132.9	12.7	38.0	Comparable to Utah Coal				60.4	72.4	6.7	7.6
UGC	Utah Coal	Comparable to Utah Coal $23.25/Ton				52.2	52.2	5.2	28.0	44.8	55.1	5.1	5.9
UGT	Utah Geothermal	107.3	107.3	10.7	41.7	220.4	415.0	41.5	74.8	(119.8)	(314.4)	(31.4)	(35.7)
UPC	Utah Compressed Air	189.3	228.6	10.7	45.6	Not Modeled in RAMPP-3							
UPS	Utah Pumped Storage	0.0	0.0	0.0	31.6	0.0	0.0	0.0	50.1	0.0	0.0	0.0	(20.5)
USL	Utah Solar	Not Modeled in RAMPP-4				0.0	0.0	0.0	137.7				
UW1	Utah Wind Non-firm	0.0	0.0	0.0	38.8	Comparable to Utah Wind w Tax C				(126.1)	(152.2)	(15.2)	(16.6)
UW2	Utah Wind Firm	0.0	0.0	0.0	48.3	Not Modeled in RAMPP-3							
UW1	Utah Wind w Tax C	Comparable to Utah Wind Non-firm				126.1	152.2	15.2	52.9	(126.1)	(152.2)	(15.2)	(16.6)
UW2	Utah Wind w/o Tax C	Comparable to Utah Wind Non-firm				126.1	152.2	15.2	65.6	(126.1)	(152.2)	(15.2)	(5.8)
WCC	Wyo Combined Cycle	189.3	228.6	16.4	30.4	264.8	475.0	34.0	47.7	(87.4)	(260.8)	(18.7)	(19.2)
WCT	Wyo Simple Cycle CT	173.8	213.1	22.5	90.7	269.8	480.0	50.6	239.3	(106.9)	(280.3)	(29.5)	(154.4)
WCY	Wyo IGCC Wyodak 2	39.3	40.9	3.3	36.4	Comparable to Wyo IGCC CT				(9.7)	(15.6)	(1.7)	0.4
WCZ	Wyo IGCC CT	40.5	42.1	3.4	36.5	46.6	53.9	4.7	33.7	(8.6)	(14.4)	(1.6)	0.5
WFB	Wyo FB Coal	Not Modeled in RAMPP-4				46.6	53.9	5.0	34.3				
WG1	Wyo PC Wyodak 2	39.3	40.9	4.6	32.3	Comparable to Wyo Coal				(9.7)	(15.6)	(1.8)	(0.8)
WG2	Wyo Coal $6.70/Ton	40.5	42.1	4.3	34.4	Comparable to Wyo Coal				(8.6)	(14.4)	(2.1)	1.1
WGC	Wyo Coal	Comparable to Wyo Coal $6.70/Ton				46.6	53.9	6.1	31.1	(8.6)	(14.4)	(2.1)	1.1
WW1	Wyo Wind Non-firm	0.0	0.0	0.0	38.8	Comparable to Wyo Wind w Tax C				(126.1)	(152.2)	(15.2)	(16.6)
WW1	Wyo Wind w Tax C	Comparable to Wyo Wind Non-firm				126.1	152.2	15.2	52.9				(16.6)
WW2	Wyo Wind w/o Tax C	Comparable to Wyo Wind Non-firm				126.1	152.2	15.2	65.6				(5.6)

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RAMPP-3 to RAMPP-4 Comparisons
Supply-Side Portfolio Costs

Short Name	Description	Full Load Heat Rate BTU/kWh		Capital Cost $/kW					Fixed Cost $/kW	
		Incremental	Average	Unit Cost	Trans-mission	Total Cap Cost	Payment Factor	Annual Pmt $/kW-Yr	Fixed O&M	Ttl Fixed $/kW-Yr
RAMPP-3 Costs										
OC1	OWC Cogen 1	5,500	5,500	$1,100	$0	$1,100	8.95%	$98.45	$5.00	$103.45
OC2	OWC Cogen 2	6,800	6,800	$663	$60	$723	8.95%	$64.71	$5.00	$69.71
OCC	OWC Combined Cycle	5,250	7,160	$687	$60	$747	8.95%	$66.86	$10.00	$76.86
UGC	Utah Coal	8,595	10,020	$1,795	$60	$1,855	8.32%	$154.34	$28.40	$182.74
WGC	Wyo Coal	9,468	11,346	$1,942	$60	$2,002	8.32%	$166.57	$28.40	$194.97
$1994 to $1996 & Carrying Charge										
OC1	OWC Cogen 1	5,500	5,500	$1,174	$0	$1,174	9.04%	$106.11	$5.34	$111.45
OC2	OWC Cogen 2	6,800	6,800	$707	$64	$772	9.04%	$69.74	$5.34	$75.08
OCC	OWC Combined Cycle	5,250	7,160	$733	$64	$797	9.04%	$72.06	$10.67	$82.73
UG1	Utah PC Hunter 4 $20/Ton	8,595	10,020	$1,915	$64	$1,979	8.37%	$165.68	$30.31	$195.99
WG1	Wyo PC Wyodak 2	9,468	11,346	$2,072	$64	$2,136	8.37%	$178.81	$30.31	$209.11
Expected Utilization and Heat Rates										
OC1	OWC Cogen 1	4,300	5,500	$1,174	$0	$1,174	9.04%	$106.11	$5.34	$111.45
OC2	OWC Cogen 2	6,200	6,800	$707	$64	$772	9.04%	$69.74	$5.34	$75.08
OCC	OWC Combined Cycle	7,167	7,517	$733	$64	$797	9.04%	$72.06	$10.67	$82.73
UG1	Utah PC Hunter 4 $20/Ton	9,583	10,062	$1,915	$64	$1,979	8.37%	$165.68	$30.31	$195.99
WG1	Wyo PC Wyodak 2	11,305	11,900	$2,072	$64	$2,136	8.37%	$178.81	$30.31	$209.11
Change in Capital Cost and O&M										
OC1	OWC Cogen 1	4,300	5,500	$1,174	$0	$1,174	9.04%	$106.13	$5.34	$111.47
OC2	OWC Cogen 2	6,200	6,800	$707	$45	$752	9.04%	$67.98	$5.34	$73.32
OCC	OWC Combined Cycle	7,167	7,517	$657	$45	$702	9.04%	$63.46	$10.67	$74.13
UG1	Utah PC Hunter 4 $20/Ton	9,583	10,062	$1,483	$50	$1,533	8.37%	$128.31	$32.39	$160.70
WG1	Wyo PC Wyodak 2	11,305	11,900	$1,527	$510	$2,037	8.37%	$170.50	$32.39	$202.89
Fuel Prices										
OC1	OWC Cogen 1	4,300	5,500	$1,174	$0	$1,174	9.04%	$106.13	$5.34	$111.47
OC2	OWC Cogen 2	6,200	6,800	$707	$45	$752	9.04%	$67.98	$5.34	$73.32
OCC	OWC Combined Cycle	7,167	7,517	$657	$45	$702	9.04%	$63.46	$10.67	$74.13
UG1	Utah PC Hunter 4 $20/Ton	9,583	10,062	$1,483	$50	$1,533	8.37%	$128.31	$32.39	$160.70
WG1	Wyo PC Wyodak 2	11,305	11,900	$1,527	$510	$2,037	8.37%	$170.50	$32.39	$202.89

RAMPP-3 to RAMPP-4 Comparisons
Supply-Side Portfolio Costs

Short Name	Description	Convert to Mills: Expected Utilization	Convert to Mills: Ttl Fixed Mills/kWh	Energy Cost: 1st Year ¢/MMBTU	Energy Cost: Levelized ¢/MMBTU	Energy Cost: Levelized Mills/kWh	Variable O&M Mills/kWh	Total Resource Cost	Change in RAMPP-3 to RAMPP4 Costs: Change in Cost	Change in RAMPP-3 to RAMPP4 Costs: Cummulative Change	Change in RAMPP-3 to RAMPP4 Costs: Percent of Total Change
RAMPP-3 Costs											
OC1	OWC Cogen 1	85%	13.89	289.8	492.6	27.09	0.50	41.49			
OC2	OWC Cogen 2	85%	9.36	289.8	492.6	33.50	0.50	43.36			
OCC	OWC Combined Cycle	80%	10.97	289.8	492.6	35.27	1.00	47.23			
UGC	Utah Coal	92%	22.58	52.2	52.2	5.23	0.24	28.05			
WGC	Wyo Coal	90%	24.73	46.6	53.9	6.11	0.24	31.08			
$1994 to $1996 & Carrying Charge											
OC1	OWC Cogen 1	85%	14.97	309.2	525.6	28.91	0.53	44.41	2.93	2.93	-19.4%
OC2	OWC Cogen 2	85%	10.08	309.2	525.6	35.74	0.53	46.36	3.00	3.00	-17.4%
OCC	OWC Combined Cycle	80%	11.81	309.2	525.6	37.63	1.07	50.51	3.27	3.27	-18.7%
UG1	Utah PC Hunter 4 $20/Ton	92%	24.21	55.7	55.7	5.58	0.26	30.05	2.00	2.00	58.5%
WG1	Wyo PC Wyodak 2	90%	26.52	49.7	57.5	6.52	0.26	33.30	2.22	2.22	179.6%
Expected Utilization and Heat Rates											
OC1	OWC Cogen 1	85%	14.97	309.2	525.6	22.60	0.53	38.10	(6.31)	(3.38)	22.5%
OC2	OWC Cogen 2	85%	10.08	309.2	525.6	32.59	0.53	43.21	(3.15)	(0.15)	0.9%
OCC	OWC Combined Cycle	85%	11.11	309.2	525.6	37.67	1.07	49.85	(0.66)	2.61	-15.0%
UG1	Utah PC Hunter 4 $20/Ton	85%	26.32	55.7	55.7	5.34	0.26	31.91	1.86	3.87	113.0%
WG1	Wyo PC Wyodak 2	85%	28.08	49.7	57.5	6.50	0.26	34.84	1.54	3.76	303.9%
Change in Capital Cost and O&M											
OC1	OWC Cogen 1	85%	14.97	309.2	525.6	22.60	0.53	38.11	0.00	(3.38)	22.5%
OC2	OWC Cogen 2	85%	9.85	309.2	525.6	32.59	0.53	42.97	(0.24)	(0.39)	2.3%
OCC	OWC Combined Cycle	85%	9.96	309.2	525.6	37.67	1.57	49.20	(0.65)	1.96	-11.2%
UG1	Utah PC Hunter 4 $20/Ton	85%	21.58	55.7	55.7	5.34	0.45	27.37	(4.54)	(0.68)	-19.8%
WG1	Wyo PC Wyodak 2	85%	27.25	49.7	57.5	6.50	0.45	34.20	(0.64)	3.12	251.9%
Fuel Prices											
OC1	OWC Cogen 1	85%	14.97	215.1	254.4	10.94	0.53	26.44	(11.67)	(15.05)	100.0%
OC2	OWC Cogen 2	85%	9.85	215.1	254.4	15.77	0.53	26.15	(16.82)	(17.21)	100.0%
OCC	OWC Combined Cycle	85%	9.96	215.1	254.4	18.23	1.57	29.75	(19.44)	(17.48)	100.0%
UG1	Utah PC Hunter 4 $20/Ton	85%	21.58	89.0	98.5	9.44	0.45	31.47	4.10	3.42	100.0%
WG1	Wyo PC Wyodak 2	85%	27.25	39.3	40.9	4.62	0.45	32.32	(1.88)	1.24	100.0%

RAMPP-3 to RAMPP-4 Comparisons
Supply-Side Portfolio Capital Costs

Potential Resource Short Name	Potential Resource Description	RAMPP-4 $1996	RAMPP-3 $1994	Difference (A) $1994 $/kW-Yr
CPU	One Year Firm Purch	$ -	$ -	$ -
HRM	Hermiston		$ 49.84	
OC1	OWC Cogen 1	$ 106.13	$ 98.45	$ 1.01
OC2	OWC Cogen 2	$ 67.98	$ 64.71	$ (1.00)
OCC	OWC Combined Cycle	$ 63.46	$ 66.86	$ (7.39)
OCT	OWC Simple Cycle CT	$ 47.56	$ 49.37	$ (4.80)
OGT	OWC Geothermal	$ 213.12	$ 196.54	$ 3.18
OPS	OWC Pump Storage	$ 71.40	$ 64.96	$ 1.95
OW1	OWC Wind Non-Firm	$ 70.63		$ (24.83)
OW2	OWC Wind Firm	$ 89.79		
OW1	OWC Wind w Tax C		$ 91.02	$ (24.83)
OW2	OWC Wind w/o Tax C		$ 122.02	$ (55.83)
UC1	Utah Cogen 1	$ 124.75	$ 115.72	$ 1.19
UC2	Utah Cogen 2	$ 79.19	$ 75.09	$ (0.88)
UCC	Utah Combined Cycle	$ 76.39	$ 71.78	$ (0.19)
UCT	Utah Simple Cycle CT	$ 57.97	$ 52.94	$ 1.38
UCY	Utah IGCC Hunter 4	$ 161.36		$ (27.87)
UCZ	Utah IGCC CT	$ 168.60	$ 179.09	$ (21.09)
UD1	Utah Gadsby Repower	$ 48.54		
UFB	Utah FB Coal		$ 209.16	
UG1	Utah PC Hunter 4 $20/Ton	$ 128.31		$ (34.09)
UG2	Utah Coal $23.25/Ton	$ 152.67		$ (11.27)
UG3	Utah Coal $27.00/Ton	$ 152.67		$ (11.27)
UGC	Utah Coal		$ 154.34	$ (11.27)
UGT	Utah Geothermal	$ 213.12	$ 196.54	$ 3.18
UPC	Utah Compressed Air	$ 84.46		
UPS	Utah Pumped Storage	$ 70.18	$ 64.96	$ 0.80
USL	Utah Solar		$ 433.26	
UW1	Utah Wind Non-firm	$ 59.77		$ (38.65)
UW2	Utah Wind Firm	$ 89.22		
UW1	Utah Wind w Tax C		$ 94.66	$ (38.65)
UW2	Utah Wind w/o Tax C		$ 134.02	$ (78.01)
WCC	Wyo Combined Cycle	$ 81.99	$ 78.67	$ (1.83)
WCT	Wyo Simple Cycle CT	$ 62.10	$ 57.80	$ 0.40
WCY	Wyo IGCC Wyodak 2	$ 200.69		$ 0.57
WCZ	Wyo IGCC CT	$ 200.69	$ 187.50	$ 0.57
WFB	Wyo FB Coal		$ 200.89	
WG1	Wyo PC Wyodak 2	$ 170.50		$ (6.79)
WG2	Wyo Coal $6.70/Ton	$ 187.91		$ 9.53
WGC	Wyo Coal		$ 166.57	$ 9.53
WW1	Wyo Wind Non-firm	$ 59.77		$ (38.65)
WW1	Wyo Wind w Tax C		$ 94.66	$ (38.65)
WW2	Wyo Wind w/o Tax C		$ 134.02	$ (78.01)

(A) Difference is [(RAMPP-4 / (1.033^2)) - RAMPP-3]

RAMPP-3 to RAMPP-4 Comparisons
Supply-Side Portfolio Transmission Costs

Potential Resource	RAMPP-3 (1994 $kW)	RAMPP-4 (1996 $/kW)	Difference * (1996 $/kW)
OWC Cogen 1	0	0	0
OWC Gas Fired	60	45	-19
OWC Geothermal	120	75	-53
OWC Pump Storage	0	75	75
OWC Wind Non-Firm	N/A	75	0
OWC Wind Firm	120	220	92
Utah Cogen 1	0	0	0
Utah Gas Fired	60	75	11
Utah Coal Hunter 4	60	50	-14
Utah Coal Beyond Hunter 4	60	130	66
Utah Gadsby Repower	N/A	70	0
Utah Geothermal	120	75	-53
Utah Compressed Air	N/A	360	0
Utah Pumped Storage	0	75	75
Utah Solar	120	N/A	0
Utah Wind Non-firm	N/A	75	0
Utah Wind Firm	212	360	134
Wyo Gas Fired	60	75	11
Wyo Coal	60	510	446
Wyo Wind Non-firm	212	75	-151
* (R-4-(R-3x1.067)=Difference			

Supply-Side Portfolio: Non-Cost Characteristics

Description	MW Available in 1st Year or Plant Size	1st Year Available	Maximum MWa Available	Depreciation Life (years)	Tax Life (years)	Heat Rate (Btu/kWh) Incremental	Heat Rate (Btu/kWh) Average	Emissions (lbs/MMBTu) NOX	Emissions (lbs/MMBTu) CO2
Utah Gadsby Repower	320	2000	331	50	35	5,039	7,846	0.0160	118
Utah Cogen 2	210	2000	420	50	35	6,200	6,800	0.0160	118
OWC Cogen 2	470	2000	1,320	50	35	6,200	6,800	0.0160	118
OWC Cogen 1	160	2000	320	50	35	4,300	5,500	0.0160	118
Utah Cogen 1	39	2000	39	50	35	4,300	5,500	0.0160	118
Utah Combined Cycle	450	2000	Unlimited	50	35	7,167	7,517	0.0160	118
OWC Combined Cycle	450	2000	Unlimited	50	35	7,167	7,517	0.0160	118
Wyo Combined Cycle	450	2000	Unlimited	50	35	7,167	7,517	0.0160	118
Utah PC Hunter 4 $20/Ton	400	2002	400	50	45	9,583	10,062	0.1000	206
Wyo PC Wyodak 2	264	2002	264	50	45	11,305	11,900	0.1000	206
Wyo Coal $6.70/Ton	330	2002	Unlimited	50	45	10,246	10,758	0.1000	206
Utah IGCC Hunter 4	262	2002	262	50	35	7,980	8,400	0.1000	206
Utah Coal $23.25/Ton	400	2002	1,250	50	45	9,583	10,062	0.1000	206
Wyo IGCC Wyodak 2	210	2002	210	50	35	7,980	8,881	0.1000	206
Wyo IGCC CT	262	2002	Unlimited	50	35	7,980	8,881	0.1000	206
Utah IGCC CT	262	2002	Unlimited	50	35	7,980	8,400	0.1000	206
Utah Coal $27.00/Ton	400	2002	1,250	50	45	9,583	10,062	0.1000	206
Utah Wind Non-firm	100	1998	200	50	20	N/A	N/A	N/A	N/A
Wyo Wind Non-firm	100	1998	200	50	20	N/A	N/A	N/A	N/A
OWC Geothermal	100	1999	300	50	30	10,000	10,000	N/A	N/A
Utah Geothermal	100	1999	300	50	30	10,000	10,000	N/A	N/A
Utah Wind Firm	150	1998	300	50	20	N/A	N/A	N/A	N/A
Wyo Wind Firm	150	1998	300	50	20	N/A	N/A	N/A	N/A
OWC Wind Non-Firm	100	1998	200	50	20	N/A	N/A	N/A	N/A
OWC Wind Firm	150	1998	300	50	20	N/A	N/A	N/A	N/A
Utah Simple Cycle CT	370	2000	Unlimited	50	30	10,556	11,083	0.0900	118
Wyo Simple Cycle CT	320	2000	Unlimited	50	30	10,556	11,083	0.0900	118
OWC Simple Cycle CT	370	2000	Unlimited	50	30	10,556	11,083	0.0900	118
OWC Bridger Trans L	500	2000	1,000	50	50	8,846	10,229	0.4500	211
OWC Htr/OWC Trans L	500	2000	1,000	50	50	9,182	10,332	0.4500	219
OWC Pump Storage	200	2001	500	75	50	N/A	N/A	N/A	N/A
Utah Compressed Air	340	2000	340	50	35	4,700	4,700	0.0160	118
Utah Pumped Storage	200	2001	200	75	50	N/A	N/A	N/A	N/A

Supply-Side Portfolio: Cost Components (in 1996 $)

	Capital Cost				Fixed Cost			Energy Cost in 2003				
Description	Unit Cost ($/kW)	Trans-mission ($/kW)	Payment Factor (%)	Annual Payment ($/kW Year)	O&M ($/kW Year)	Expected Utilization Rate	Ttl. Capital & Fixed Cost (Mills/kWh)	1st Year (Cent/ MMBTU)	Levelized (Cent/ MMBTU)	Levelized (Mills/ kWh)	Variable O&M (Mills/kWh)	TOTAL COST (Mills/kWh)
Utah Gadsby Repower	$827	$70	9.04%	81.09	2.13	85%	11.18	200.2	235.2	11.85	0.31	23.34
Utah Cogen 2	$831	$45	9.04%	79.19	5.34	85%	11.35	200.2	235.2	14.58	0.53	26.47
OWC Cogen 2	$707	$45	9.04%	67.98	5.34	85%	9.85	226.0	261.0	16.18	0.53	26.56
OWC Cogen 1	$1,174		9.04%	106.13	5.34	85%	14.97	226.0	261.0	11.22	0.53	26.72
Utah Cogen 1	$1,380		9.04%	124.75	5.34	85%	17.47	200.2	235.2	10.11	0.53	28.12
Utah Combined Cycle	$770	$75	9.04%	76.39	10.67	85%	11.69	200.2	235.2	16.86	1.57	30.12
OWC Combined Cycle	$657	$45	9.04%	63.46	10.67	85%	9.96	226.0	261.0	18.71	1.57	30.23
Wyo Combined Cycle	$832	$75	9.04%	81.99	10.67	85%	12.44	200.2	235.2	16.86	1.57	30.87
Utah PC Hunter 4 $20/Ton	$1,483	$50	8.37%	128.31	32.39	85%	21.58	91.8	100.1	9.59	0.45	31.62
Wyo PC Wyodak 2	$1,527	$510	8.37%	170.50	32.39	85%	27.25	39.8	41.1	4.65	0.45	32.35
Wyo Coal $6.70/Ton	$1,735	$510	8.37%	187.91	32.39	85%	29.59	41.0	42.4	4.34	0.45	34.38
Utah IGCC Hunter 4	$1,735	$50	9.04%	161.36	30.35	85%	25.75	91.8	100.1	7.99	2.13	35.86
Utah Coal $23.25/Ton	$1,694	$130	8.37%	152.67	32.39	85%	24.85	106.7	116.3	11.15	0.45	36.45
Wyo IGCC Wyodak 2	$1,710	$510	9.04%	200.69	30.35	85%	31.03	39.8	41.1	3.28	2.13	36.44
Wyo IGCC CT	$1,710	$510	9.04%	200.69	30.35	85%	31.03	41.0	42.4	3.38	2.13	36.54
Utah IGCC CT	$1,735	$130	9.04%	168.60	30.35	85%	26.72	106.7	116.3	9.28	2.13	38.13
Utah Coal $27.00/Ton	$1,694	$130	8.37%	152.67	32.39	85%	24.85	123.9	135.1	12.95	0.45	38.25
Utah Wind Non-firm	$1,000	$75	5.56%	59.77	60.84	36%	38.78	0.0				38.78
Wyo Wind Non-firm	$1,000	$75	5.56%	59.77	60.84	36%	38.78	0.0				38.78
OWC Geothermal	$2,145	$75	9.60%	213.12	15.00	90%	28.93	107.3	107.3	10.73	2.00	41.66
Utah Geothermal	$2,145	$75	9.60%	213.12	15.00	90%	28.93	107.3	107.3	10.73	2.00	41.66
Utah Wind Firm	$1,000	$360	6.56%	89.22	60.84	36%	48.25	0.0				48.25
Wyo Wind Firm	$1,000	$365	6.57%	89.68	60.84	36%	48.40	0.0				48.40
OWC Wind Non-Firm	$1,000	$75	6.57%	70.63	50.00	28%	49.18	0.0				49.18
OWC Wind Firm	$1,000	$220	7.36%	89.79	50.00	28%	56.99	0.0				56.99
Utah Simple Cycle CT	$549	$75	9.29%	57.97	22.58	15%	61.30	184.7	219.7	23.19	3.73	88.22
Wyo Simple Cycle CT	$594	$75	9.29%	62.10	22.58	15%	64.45	184.7	219.7	23.19	3.73	91.37
OWC Simple Cycle CT	$467	$45	9.29%	47.56	36.98	15%	64.34	190.9	225.9	23.85	3.73	91.92
OWC Bridger Trans L		$1,240	8.37%	103.79		100%	11.85	97.1	97.1	8.59		20.44
OWC Htr/OWC Trans L		$1,240	8.37%	103.79		100%	11.85	104.1	104.1	9.56		21.40
OWC Pump Storage	$800	$75	8.16%	71.40	13.00	30%	32.12	0.0				32.12
Utah Compressed Air	$675	$360	8.16%	84.46	4.32	30%	33.78	200.2	235.2	11.06	1.10	45.94
Utah Pumped Storage	$785	$75	8.16%	70.18	13.00	30%	31.65	0.0				31.65

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RAMPP-3 to RAMPP-4 Comparisons
End-Effects Years (2016-2045) Modeling Assumptions

	RAMPP-3	RAMPP-4
Loads	Flattened after 20 Years	
Sales	Flattened after 20 Years Year 1 - 20 No renewal after contract termination	
Purchases	Year 21 - 50 All contract life extended to end of study period	
Fuel Prices	Escalated for 50 Years	Flattened after 20 Years
Non-Firm Sales	Escalate with gas price to 2013	Escalate with gas price to 2015
Prices	Then sales terminated	Then sales terminated
Non-Firm Purchase	Escalate with gas price to 2043	Escalate with gas price to 2015
Prices	Purchases allowed to continue	Then purchases terminated
Plant Life	Continual Renewal	
DSM	Ended at 20-years	May continue for 20-year life if selected after 1996

Differences in the Cost of Capital: RAMPP-4 to RAMPP-3

The cost of capital analysis is driven primarily by Data Resources Inc.'s (DRI) long term view of interest rates and the historical relationship of PacifiCorp's capital resource costs to interest rates. RAMPP-4 projections for the cost of capital, which reflects DRI's Summer 1994 view of relatively low interest rates over the next 20 years, are lower than RAMPP-3. RAMPP-3 costs were based on DRI's Winter 1992 forecast. Also contributing to the lower capital costs is the fact that credit ratings on PacifiCorp first mortgage bonds and preferred stock were upgraded since the last least cost plan. Bonds were upgraded to A from A-, while preferred stock was upgraded to A- from BBB+.

The cost of debt declines to 8.60% in RAMPP-4 from 8.99% in RAMPP-3. The 39 basis change is due primarily to a 33 basis point reduction in DRI's 20-year forecasted cost of debt with the remainder of the change attributable to an improved credit rating. Note that 100 basis points equals 1%.

The cost of preferred stock changed more than any other category dropping from 8.93% to 8.11%. DRI's 33 basis point reduction in the forecasted cost of debt was a significant contributor to the change; however, the largest single factor in the cost reduction was the improved credit rating. Many institutions, such as municipalities or pension funds, are not allowed to purchase lower quality BBB rated securities. The market for securities rated A or better is much more competitive and the company benefits through the lower dividend yield it pays to investors. The change in market yields from BBB+ to A- is significantly greater than the change in yields from A- to A. Improved credit ratings reduced the cost of preferred stock by 49 basis points.

While the cost of debt and preferred stock is largely driven by interest rates, the cost of common equity is a function of many factors, with interest rates being just one of the influences. RAMPP-4 projects only a 20 basis point decline in the cost of equity for the twenty year planning horizon compared to RAMPP-3. Recent volatility in the price of utility stocks has been extreme. Share prices are down more than 20% from peak prices a year ago. Based on an environment of stable and low interest rates and reliance upon historical cost relationships, the Company projects a 12% cost of equity for the RAMPP-4 horizon.

Capitalization ratios changed slightly since the last least cost plan with the equity ratio increasing 1% to 46%. The capitalization projected for RAMPP-4 is based on the 1993 average capitalization of comparable companies. This methodology is the same as that used in RAMPP-3. Across the industry utilities are increasing the amount of common equity in their capital structures. Increased risks of competition and increasing credit standards of the rating agencies contribute to a need for added equity.

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Chapter 2:

Inputs

EVALUATION OF THE IPM MODEL

Prepared for:

PacifiCorp

Prepared by:

Resource Management International, Inc.

INTRODUCTION

Resource Management International, Inc. (RMI) performed a focused review of PacifiCorp's RAMPP-3 Integrated Resource Planning Model (IPM). The focused review concentrated on: (i) inspecting the IPM model costs and expenses; (ii) evaluating the IPM model and its applicability to PacifiCorp's System; (iii) evaluating the level of modeling accuracy; and (iv) examining what should reasonably be expected of an Integrated Resource Planning (IRP) model in utility decision making. This Report assumes that the reader has a basic understanding of the IPM model and attended RAMPP-3 Advisory Group (RAG) technical modeling meetings.

RMI performed this assignment through: (i) inspecting the costs and expenses of the current model and proposed enhancements; (ii) reviewing the IPM documentation; (iii) examining the model's process of selecting new resources; (iv) inspecting internal and external correspondence about the IPM model; and (v) conducting interviews and asking questions of PacifiCorp's staff. RMI's assignment did not involve review of the Demand Side Resource (DSR) module, the financial module or verification of PacifiCorp assumptions, nor did RMI review the computer code for the IPM model.

IPM is a least-cost planning tool that uses a linear programming approach. The model's objective function minimizes the present value of future capital and operating costs over a planning horizon and considers the "end effects" covering a 50-year period. The model can select new resources including demand side and supply side resources while maintaining the required reserve margin and determine if non-firm sales and purchases should be made. PacifiCorp eliminated the energy surplus constraint used in prior RAMPP studies because the IPM model considers transmission constraints.

RMI's findings, conclusions, and recommendations immediately follow this Introduction; the remainder of this report is separated into three distinct sections. Section One reviews the IPM model expenses and discusses the model's documentation and consulting support. Section Two evaluates the IPM model, its applicability to PacifiCorp's System, and model accuracy. Section Three discusses the use of Integrated Resource Planning models in management decision making.

RMI'S FINDINGS, CONCLUSIONS, AND RECOMMENDATIONS

1. RMI finds that the costs and expenditures incurred, through July 1994, by PacifiCorp for the IPM model seem reasonable. The modifications made to the IPM model reflect the customized features necessary to model the diverse PacifiCorp utility system operation and constraints. PacifiCorp incorporated known constraints, of a non-economic nature, into the model.

2. RMI finds that PacifiCorp staff has been sufficiently trained to operate the model. RMI is of the opinion that PacifiCorp staff has the full capability and knowledge to make changes to IPM computer code. However, the licensing agreement signed with the contractor (ICF) precludes PacifiCorp staff from making direct computer code changes. RMI recommends that PacifiCorp obtain a hard copy of IPM's complete computer program. It is further recommended that PacifiCorp use an electronic version of the IPM Reference Manual, and supplement it by inserting PacifiCorp's own internal memos and notes based on issue identification and the knowledge gained from working with the model.

3. IPM is a deterministic model and does not consider probability or uncertainty of events, except through independent modeling studies. The switch from a stochastic to a deterministic optimization model was made at the request of the RAMPP-3 Advisory Group (RAG) members. RMI recognizes that PacifiCorp's staff performed an extensive number of computer studies incorporating a broad range of futures and scenarios throughout the planning horizon. PacifiCorp evaluated uncertainty by making over 155 computer runs using the IPM model and changing assumptions.

4. RMI has concluded that the IPM input file format contains insufficient provisions for comments and lacks data unit identification. RMI recommends that PacifiCorp staff clearly document and update the input files so that the source and vintage of the data being used is readily apparent.

5. RMI recognizes that PacifiCorp followed the intended approach and applied the environmental cost adders according to the Oregon Public Utility Commission's Order UM-424 in resource selection and dispatch in IPM. "The IPM model selected new resources as if the adders were real, but the financial model operated as if the company did not have to pay the adder costs."

6. The selected cases for testing with environmental cost adders are generally reasonable. The analysis could have been improved by selecting a high growth case in order to test the amount of resource shift in this situation.

7. RMI agrees that the primary results of PacifiCorp's environmental adders to the existing dispatch analysis showed an increase in non-firm purchases and a decrease in non-firm sales. It was virtually impossible to determine which type of resource (non-firm hydro or thermal) is used in the model's non-firm energy transactions. The environmental

dispatch cases show reduced PacifiCorp emissions, but west coast or regional emissions could increase or decrease.

8. If PacifiCorp used the Multi-Attribute Trade-Off (MATO) approach in a wider variety of resource strategies and a different specification of alternatives for each strategy the results would have been more informative.

9. PacifiCorp's 1994 and 2003 benchmarking studies compared IPM results to those obtained from MULTISYM, a system operations model. These studies demonstrated that there was not much difference in overall existing base load and new resource generation, total load requirements and non-firm purchases/sales. The variation between the two models can be explained as, (i) that IPM dispatches using a load duration curve while MULTISYM dispatches units on an hourly basis, (ii) MULTISYM tends to be more conservative in making non-firm sales.

10. RMI finds that PacifiCorp did sufficient scenario evaluations to demonstrate how the new resource selections could be impacted by alternative futures and resource strategies.

11. RMI concludes that PacifiCorp's use of average water conditions in IPM is a reasonable approach.

12. RMI finds that PacifiCorp's approach in considering "end effects" is reasonable.

13. The IPM model selected the appropriate resources in the portfolio sensitivity studies done by PacifiCorp based on the assumptions used for the resource alternatives. Specifically:

    A. PacifiCorp's contract with Southern California Edison Company (Edison) was modeled as an existing resource in most cases. A sensitivity study was performed in which the Edison purchase was treated as a potential resource to determine if it would be selected by the IPM model. In modeling the Edison purchase as a potential new resource, PacifiCorp assumed that the Levelized Total Cost (LTC) for the purchase would be approximately 129 mills/kWh and that it would be available in 1994. IPM did select the Edison purchase as coming "on-line" over a period of 3 years. This selection by the model appears reasonable based on the potential timing and pricing of alternative peaking resources.

    B. In modeling Hermiston as a potential new resource, PacifiCorp assumed that it would be available in 1996 and would have a Levelized Total Cost (LTC) of 33.2 mills/kWh. The results of the Hermiston sensitivity studies show that, based on LTC; (i) the selection of Hermiston in place of other cogeneration resources in the OWC and Utah areas (whose LTCs range from 43.4 mills to 43.6 mills/kWh); or (ii) the selection of Hermiston in place of other cogeneration resources in the OWC area (whose LTCs range from 41.5 mills to 43.6 mills/kWh) and of OWC pumped storage (with a LTC of 50.3 mills/kWh) appears to be appropriate.

C. In RMI's opinion, PacifiCorp reasonably evaluated transmission sensitivities by examining constraints and capacity upgrades, and the effects that such upgrades would have on resource selection. The information reviewed by RMI shows that the existing transmission limits on two key paths (Bridger-OWC and Utah-OWC) were reached during the mid-peak and off-peak load segments during all but the spring season. Increasing the limits of the Bridger-OWC link and the Utah-OWC link from 1,500 to 1,800 MW and from 90 to 690 MW, respectively, resulted in the installation of additional new resources in the Utah area.

14. RMI is reasonably convinced that the IPM model will not select a new resource just to achieve a non-firm energy sale by PacifiCorp and that, from an overall System perspective, inclusion of non-firm markets is not biasing the RAMPP-3 results.

15. RMI has concluded that results from IPM should be used as one of the inputs in management's decision process.

PacifiCorp
Major IPM Modeling Input Assumptions

Coal Prices

Utah Coal Cost $/ton		Mine Cost		Delivery $/ton		Total $1996	Real Escalation
First Unit (400 MW)	$	17.50	$	2.50	$	20.00	2.7%
Next 1,250 MW	$	20.75	$	2.50	$	23.25	2.7%
All other MW	$	24.50	$	2.50	$	27.00	2.7%
Wyoming Coal Costs $/ton							
First Unit	$	4.50	$	2.00	$	6.50	0.4%
All other MW	$	4.70	$	2.00	$	6.70	0.4%

Gas Prices

Gas Prices	¢/mmbtu
Gas Price	140.0
5% Tax & Shrinkage	7.0
Total $1995	147.0
Total $1996	151.9

Real Escalation Rates	
Low	0.00%
Medium	2.11%
High	3.78%

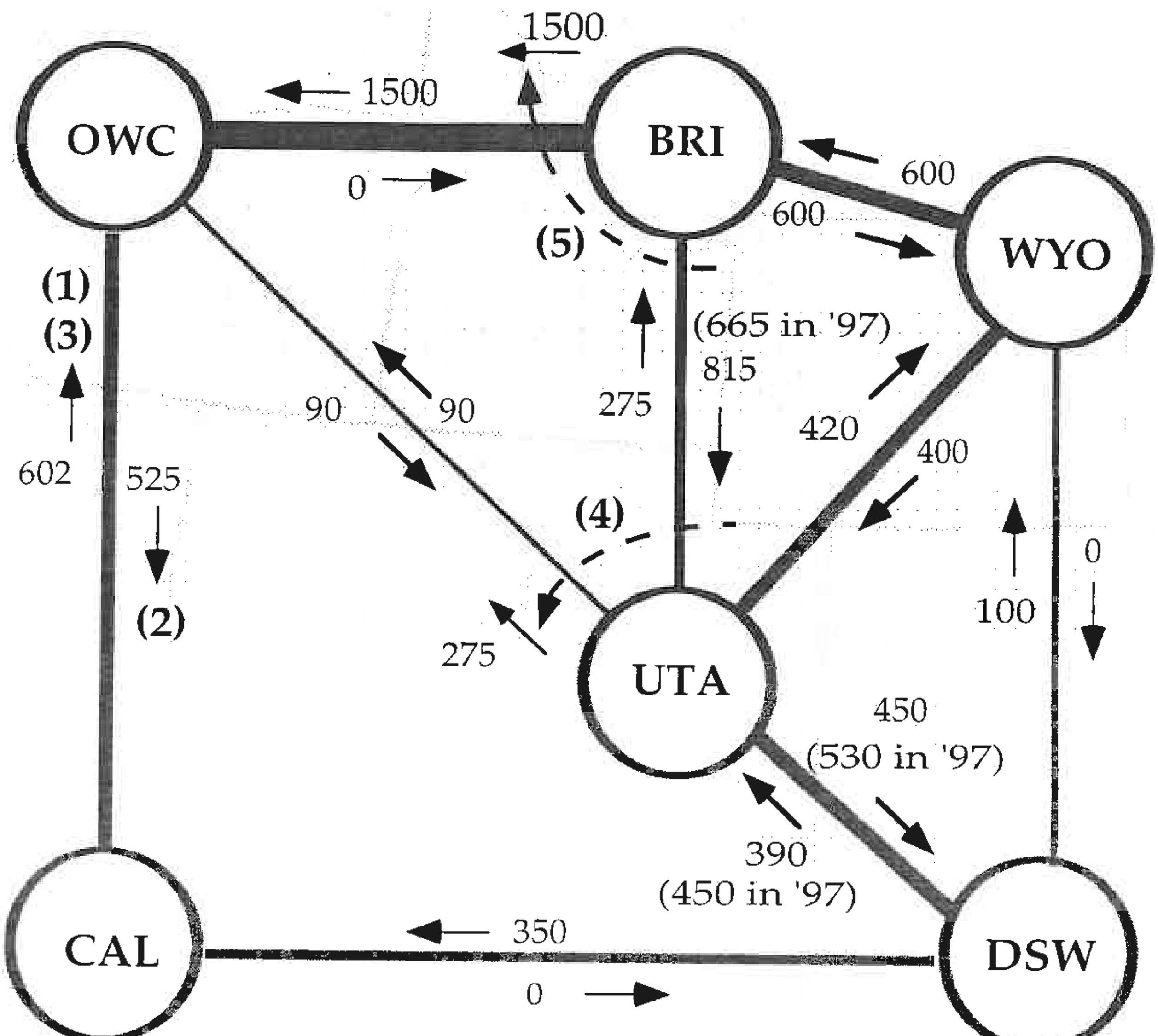
Gas Transportation & Storage $1996	Combined Cycle		Simple Cycle			
	West	East	West		East	
¢/mmbtu	46.50	20.70		11.40		5.20
$/kW			$	21.51	$	35.91

Non-Firm Market Prices

Non-firm Market Prices	mills
On Peak	19.0
Off Peak	16.0

Real Escalation Rates	
Low	0.00%
Medium	1.70%
High	3.02%

Geographic Areas and Transfer Capabilities (MW)



Transfer Capabilities (MW) are Pacificorp's inter-regional winter transfer capabilities utilized for RAMPP-4 Studies.

(1) 602 MW modeled as 260MW off-peak capability in selected studies.
(2) Subject to change depending on final Non-Federal-Participation allocation or long term contract discussions.
(3) Subject to change depending on final South to North Pacific Intertie rating.
(4) In studies, the combined flow of the UTA to BRI and the UTA to OWC paths is limited to the capability of the UTA to BRI path.
(5) In studies, the combined flow of the BRI to UTA and the BRI to OWC paths is limited to the capability of the BRI to OWC path.

Medium-Low Load Forecast
by Geographic Area
(consistent with areas used in the IPM model)

Year	OWC			Utah			Wyoming		
	Winter	Summer	Energy	Winter	Summer	Energy	Winter	Summer	Energy
1996	3804	2943	2327	2440	3037	1981	939	912	834
1997	3859	2950	2353	2446	3125	1977	837	752	738
1998	3889	2972	2371	2466	3152	1991	812	761	715
1999	3930	2974	2396	2484	3199	2005	822	785	724
2000	3986	3085	2438	2512	3218	2032	835	787	738
2001	4043	3089	2465	2540	3257	2055	853	798	751
2002	4097	3144	2498	2579	3307	2080	871	821	767
2003	4159	3181	2535	2624	3365	2116	890	839	784
2004	4219	3266	2580	2670	3421	2159	911	850	805
2005	4269	3262	2603	2703	3468	2180	923	867	813
2006	4317	3269	2632	2738	3530	2207	938	904	827
2007	4379	3311	2670	2778	3580	2239	951	914	838
2008	4442	3439	2716	2822	3606	2280	970	898	858
2009	4498	3406	2741	2858	3683	2304	983	947	867
2010	4556	3482	2777	2896	3708	2334	997	936	878
2011	4615	3527	2813	2934	3754	2364	1009	946	889
2012	4674	3618	2858	2967	3779	2396	1019	966	901
2013	4726	3630	2881	2994	3827	2412	1028	969	907
2014	4779	3643	2904	3022	3876	2427	1038	973	912
2015	4832	3656	2927	3050	3925	2442	1047	976	917

PacifiCorp

RAMPP-4

1994 Actual Sales & 1995 Estimated Sales

Year	Oregon	Washington	Montana	California	E. Wyoming	S. Idaho	W. Wyoming	Utah	Pacificorp
1994	13137073	3717372	775342	763609	5645233	2961278	2020093	14437687	43459681
1995	13610913	3895143	796455	761911	5830117	3070879	1518231	15219081	44704725

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RAMPP-4 Forecasts

RAMPP IV Medium Sales Forecast (Megawatt Hours)

Year	Oregon	Washington	Montana	California	Eastern Wyoming	Southern Idaho	Western Wyoming	Utah	PacifiCorp
1996	13,382,307	4,042,573	815,098	781,218	5,816,642	2,958,144	1,318,997	15,231,223	44,346,202
1997	13,659,796	4,148,197	836,629	796,368	5,859,050	2,985,841	1,061,544	15,835,371	45,182,796
1998	13,862,897	4,221,444	849,223	811,023	5,980,019	3,005,268	906,011	16,310,997	45,946,882
1999	14,115,102	4,312,240	863,247	829,027	6,088,482	3,036,967	789,625	16,750,344	46,785,034
2000	14,430,326	4,412,033	881,132	852,113	6,219,229	3,079,720	780,000	17,175,004	47,829,557
2001	14,749,212	4,519,375	897,906	876,041	6,379,791	3,131,756	770,000	17,572,763	48,896,844
2002	15,059,396	4,625,987	914,948	900,719	6,551,536	3,189,642	760,000	17,989,746	49,991,974
2003	15,406,263	4,738,514	933,807	927,733	6,726,317	3,262,021	750,000	18,444,348	51,189,003
2004	15,753,089	4,850,301	953,562	955,194	6,914,604	3,333,964	760,000	18,909,509	52,430,223
2005	16,054,166	4,953,257	972,896	981,735	7,040,818	3,382,416	770,000	19,294,488	53,449,776
2006	16,346,117	5,053,965	992,790	1,008,317	7,192,290	3,423,630	780,000	19,679,262	54,476,371
2007	16,705,934	5,161,864	1,015,389	1,039,174	7,325,335	3,474,926	790,000	20,104,952	55,617,574
2008	17,079,773	5,275,471	1,039,725	1,072,194	7,508,685	3,528,004	800,000	20,592,262	56,896,114
2009	17,395,428	5,378,540	1,061,196	1,099,880	7,650,441	3,571,454	810,000	21,033,024	57,999,963
2010	17,718,212	5,480,788	1,082,709	1,127,430	7,792,789	3,616,945	820,000	21,488,266	59,127,139
2011	18,045,811	5,583,173	1,104,863	1,155,503	7,927,598	3,663,875	830,000	21,944,145	60,254,968
2012	18,372,448	5,679,677	1,127,956	1,185,158	8,054,425	3,701,710	840,000	22,359,834	61,321,208
2013	18,666,685	5,769,416	1,150,655	1,214,070	8,166,915	3,729,657	850,000	22,737,880	62,285,278
2014	18,965,634	5,860,573	1,173,811	1,243,687	8,280,977	3,757,815	860,000	23,122,318	63,264,814
2015	19,269,371	5,953,170	1,197,433	1,274,027	8,396,631	3,786,186	870,000	23,513,255	64,260,073

RAMPP-4 Forecasts

RAMPP IV Medium High Sales Forecast (Megawatt Hours)

Year	Oregon	Washington	Montana	California	Eastern Wyoming	Southern Idaho	Western Wyoming	Utah	PacifiCorp
1996	14,177,991	4,173,960	851,604	832,097	6,204,149	3,031,607	1,433,655	15,848,440	46,553,503
1997	14,630,100	4,315,181	882,686	857,855	6,342,703	3,081,580	1,415,695	16,645,100	48,170,900
1998	15,014,474	4,416,182	904,616	881,893	6,483,281	3,123,023	1,454,547	17,306,997	49,585,013
1999	15,454,250	4,538,985	928,257	908,800	6,615,239	3,179,170	1,476,684	17,935,007	51,036,392
2000	15,967,784	4,673,178	956,279	940,755	6,772,182	3,248,193	1,500,844	18,553,797	52,613,012
2001	16,491,437	4,816,883	983,347	973,370	6,961,394	3,328,360	1,529,545	19,155,911	54,240,247
2002	17,011,425	4,961,603	1,010,938	1,006,691	7,164,037	3,416,216	1,557,693	19,782,835	55,911,437
2003	17,582,533	5,114,392	1,040,755	1,042,527	7,371,806	3,521,136	1,583,094	20,459,694	57,715,937
2004	18,152,034	5,264,911	1,071,448	1,077,222	7,594,440	3,626,081	1,609,508	21,157,824	59,553,468
2005	18,674,848	5,406,798	1,101,888	1,110,983	7,753,195	3,707,479	1,622,826	21,772,042	61,150,059
2006	19,191,669	5,547,264	1,133,125	1,144,897	7,938,175	3,782,667	1,641,217	22,390,752	62,769,766
2007	19,795,464	5,696,972	1,167,599	1,183,606	8,106,046	3,870,422	1,652,008	23,063,696	64,535,813
2008	20,399,089	5,853,398	1,204,299	1,224,927	8,327,171	3,961,777	1,672,238	23,777,524	66,420,423
2009	20,912,724	5,998,601	1,237,992	1,261,220	8,506,575	4,044,248	1,682,720	24,445,886	68,089,965
2010	21,424,686	6,143,619	1,271,945	1,298,069	8,687,904	4,130,690	1,692,466	25,139,142	69,788,521
2011	21,937,235	6,289,575	1,306,846	1,336,024	8,862,570	4,220,469	1,699,922	25,840,915	71,493,556
2012	22,444,835	6,429,550	1,343,019	1,376,151	9,029,126	4,301,714	1,705,684	26,501,625	73,131,704
2013	22,910,788	6,562,101	1,378,936	1,415,784	9,181,107	4,373,535	1,708,390	27,124,003	74,654,644
2014	23,386,414	6,697,385	1,415,814	1,456,558	9,335,646	4,446,555	1,711,101	27,760,997	76,210,470
2015	23,871,914	6,835,457	1,453,677	1,498,507	9,492,786	4,520,794	1,713,816	28,412,951	77,799,903

PacifiCorp is continuing to review opportunities to maximize the return of the Company's assets. One opportunity are design improvements developed over the last few year for steam turbine blades. Advanced computer-assisted engineering and more sophisticated manufacturing techniques have improved the efficiency of turbine blades. Steam turbine manufacturers are recognizing the potential to retrofit new blades into existing steam turbines to both increase capacity and reduce heat rate.

The steam turbine upgrades currently planned for the PacifiCorp system consist of two primary items. The Hunter 3 boiler will be upgraded to perform at its original design condition. Additional improvements to the steam turbine will allow a capacity increase. The goal is to increase net output from the Hunter 3 unit by 70 MW. The second effort will be to retrofit the GE steam turbines in the system with new Advanced Aero steam turbine blade designs. Approximately 79.4 MW of additional capacity can be obtained through these retrofits.

Hunter 3

The Hunter 3 boiler was purchased to operate at a maximum rate of 3,341,000 lb steam/hour. Operating at steam production levels close to this design rate in the mid 1980's resulted in substantial damage to the Hunter 3 boiler. Boiler steam output was reduced by approximately 10% to avoid a repeat of the problems experienced. Subsequent litigation against the boiler manufacturer resulted in damage awards to PacifiCorp. Negotiations with the boiler manufacturer have identified modifications to the boiler to restore the original design capacity. These modifications would be implemented as a part of the litigation settlement. Modifications center on the replacement of portions of the superheat tubes and the installation of rotating classifiers in place of the existing stationary classifiers on the boiler pulverizers.

In anticipation of the boiler improvements the steam turbine manufacturer (GE) was contacted about potential steam turbine modifications to better utilize the restored steam flow. Because the higher steam flow can occur at pressures approximately 5% higher than the normal design pressure of 2400 psig, after the proposed modifications, overpressure operation can be conducted in the future. The steam turbine can operate more efficiently at these higher pressures if the diaphragms and nozzle blocks are redesigned. GE recommended that not only the turbine clearances be redesigned but that the turbine blades in the High Pressure (HP) and Intermediate Pressure (IP) sections of the boiler should be replaced with their Advanced Aero package.

The Advanced Aero turbine blade package consists of turbine blades which have been designed with new computer modeling techniques to allow the blades to focus more of the steam into the center of the subsequent blades therefore increasing efficiency by reducing steam loss at the edges of the blades. The redesigned blades also have a secondary benefit in that the redesigned first stage, combined with improved blade coatings, will reduce Solid

Particle Erosion (SPE) of the turbine blades allowing design conditions to be maintained for longer periods of time.

The Advanced Aero design concept can improve capacity by as much as 2% and improve turbine cycle heat rate by a minimum of 1.5%. For the Hunter 3 turbine the Advanced Aero portion of the capacity increase is approximately 12 MW and the overall heat rate improvement is about 200 Btu/kWh. The restoration of the steam flow combined with turbine nozzle block additions will add another 38 MW with overpressure operation increasing output by 20 MW. Overall the cost to provide this added capacity will be approximately $210/kW in 1996 dollars.

Other GE Steam Turbines

As a result of the discussions concerning Hunter 3, GE was asked to provide information on the potential advantages of retrofitting the Advanced Aero design steam turbine blades on other large GE steam turbines in PacifiCorp's system. Table 3-12 identifies the units planned for upgrade and the capacities before and after modifications. The projected average net unit heat rate improvement for each unit are also indicated. Each unit is planned for its upgrade during the next regularly scheduled unit overhaul as indicated.

The cost effectiveness of the upgrades will vary from unit to unit because the cost of the turbine blade package is similar yet the units have different capacities . Generator capacity, transformer capacity, and transmission availability all will go into the final implementation decision. Despite the cost of the turbine upgrade approaching $400 to $600/kW in some cases, economic analysis still favors the upgrade since the proposed capacity and energy are obtained at no, or very little, fuel expense. Each unit must be evaluated separately to determine the ultimate feasibility of upgrading the steam turbine.

Other steam turbine manufacturers are looking into the modification of steam turbines with similar advanced designs. Some turbine manufacturer's are marketing replacement components for competitor's machines as well as their own. Upgrading components in the existing steam plants will continue to be a potential source of increased generation capacity.

GE TURBINE UPGRADES

TABLE 3-12

Unit	Net RAMPP-3 Capacity MW (PacifiCorp Only)	Net Proposed RAMPP-4 Capacity MW (PacifiCorp Only)	MW Increase from Turbine Upgrades	1996 $/kW for Turbine Upgrade	Year of Turbine Upgrade
Dave Johnson #4	330.0	338.0	8.0	$613	1999
Jim Bridger #1	346.8	354.8	8.0	$367	1999
Jim Bridger #2	346.8	354.8	8.0	$367	1998
Jim Bridger #3	346.8	354.8	8.0	$367	1997
Jim Bridger #4	346.8	354.8	8.0	$367	2000
Wyodak	256.0	262.4	6.4	$613	1999
Cholla #4	390.0	401.0	11.0	$450	1997
Hunter #3	395.0	465.0	70.0	$210	1997
Huntington #1	420.0	432.0	12.0	$412	1997
Huntington #2	425.0	435.0	10.0	$396	2001
Total	3,603.2	3,752.6	149.4	$49,125,200	

Notes:

Hunter 3 upgrades include the capacity addition from overpressure operation

Aero Turbine upgrades are expected to improve turbine cycle heat rate by 1.5% except for Huntington 1 which is 1.7%

RAMPP-4 Generation Resource Options

November 1994

The generation resource option list from RAMPP-3 has been updated to reflect new information and 1996 costs. The generation resource option list is shown on the attached Table. Information is given concerning unit size, the available MW capacity of each resource, project lead time, capacity factor, 1996 overnight capital costs (including all Owners and AFUDC expense but not including transmission or substation costs), and O&M estimates. Information on expected full load emissions for each option are also given.

The following items represent the principal changes between the RAMPP-3 data and this new RAMPP-4 data base.

1. Costs have been updated to 1/1/96 values. In most cases an escalation rate of 3.3% was used.

2. Selective Catalytic Reduction (SCR) has been added to the Pulverized Coal (PC) cost estimates for NOx control. SCR uses a catalyst combined with ammonia injection to convert NOx to nitrogen and water. While SCR has been used on Japanese and German power plants for the last ten years it is only in the last year that SCR is being incorporated into new power plants being built in the United States. There is an increasing possibility that SCR will be required as Best Available Control Technology (BACT) for NOx for future coal-fired steam plants.

3. Fluidized-bed Coal has not been included as an option. It is felt that the environmental performance of PC/SCR combined with the lower estimated cost of PC/SCR makes this technology a preferred option for coal-fired generation. Fluidized-bed boilers (atmospheric) are considered an equipment option for a conventional steam plant and may have some site-specific reasons for selection but does not represent a significant enough change from PC/SCR to warrant separate consideration.

4. An option to repower the existing gas-fired steam units at the Gadsby Plant has been added. Repowering would consist of adding to each existing unit an advanced gas turbine along with a Heat Recovery Steam Generator (HRSG) to take the gas turbine exhaust and generate steam for use in the existing steam turbines. This concept would more than double the capacity of each unit while improving the efficiency of the units by about 50%, while reducing emissions. This modification to the Gadsby Plant would effectively convert the existing steam units to a combined cycle facility. Costs are presented for both the incremental capacity (and incremental fuel, O&M) and for the non-incremental costs which represent the full Plant performance after repowering. Additional information on Gadsby Repowering is attached.

5. A Compressed Air Energy Storage (CAES) plant was included for consideration. Such a plant would compress air into a natural cavern using the compressor on a gas turbine

using off-peak coal energy and then use the energy on-peak by firing natural gas. Such a system has been installed in Germany and Alabama and developers are pursuing such options in the West. The costs used reflect one such proposal in Arizona. Additional information on the CAES technology is attached.

6. The wind projections reflect the expected costs from the Columbia Hills and Foote Creek developments in the OWC and Wyoming regions, respectively. Lead times in these two areas for future wind generation is one to two years since a significant amount of permitting and development has already occurred. Development of wind in Utah can be expected to take longer.

7. Only large simple cycle combustion turbine costs have been included. Smaller combustion turbines, in the 85-100 MW size range, are more costly than the larger advanced machines and would not be selected by the model. Costs for the simple cycle machines represent the average of an initial unit and an extension unit. It is believed that a two unit simple cycle gas turbine plant would most likely be built in any one location. Because of the low capacity factor of a simple cycle gas turbine peaking facility, emissions are assumed to be controlled to 25 ppm without the use of SCR.

8. Large combined cycle facilities are represented by an "F" type technology single gas turbine facility. Each such unit is considered a separate resource and the cost estimates assume a one unit plant. It is assumed that SCR will be required to permit a combined cycle plant.

9. Integrated Gasifier Combined Cycle (IGCC) plants have been included because of their superior environmental characteristics and the increasingly commercial status of the technology. It may not be possible to permit a coal facility with emissions greater than an IGCC plant therefore the cost of IGCC may represent BACT for coal generation.

10. Operating and maintenance costs were updated to reflect the latest information especially in regard to gasification and pulverized coal units with SCR.

Detailed cost estimating sheets for each of the major fossil fuel technologies were prepared and are attached. These estimates assumed that a facility would be started in 1996 with escalation of 3.3% per year and a cash flow as indicated. Costs are presented as overnight construction costs in 1996 with AFUDC included in real (non-escalated dollars). These spreadsheets assume that all PacifiCorp Indirect costs are included in the PacifiCorp Indirect cost component. PacifiCorp Indirect's include non-engineering PacifiCorp personnel, A&G expense, working capital, startup, and other Owner indirects as required.

Heat rates are assumed to be average annual estimates not full load design. Approximately 5% has been added to the design values to reflect startups, shutdowns, and partial load operation for the fossil technologies.

The attached list does not include potential additional capacity as may be obtained from efficiency and capacity improvements to the coal-fired generation already in operation by PacifiCorp.

RAMPP-4 GENERATION RESOURCE OPTIONS

	Capacity Unit Size (MW)	Maximum Available (MW)	Lead Time (yrs)	Maximum Cap. Factor (%)	Average Annual Heat Rate (HHV) (Btu/kWh)	1996 Cap. Cost $/kW	Fixed O&M $/kW-yr	Var. O&M $/MWh	EMISSONS SO2 lb/MMBtu	NOx lb/MMBtu	TSP lb/MMBtu	CO lb/MMBtu	CO2 lb/MMBtu
OWC:													
Cogen 1	50	320	3.5	85%	5,500	$1,174	$5.34	$0.53	0.0006	0.030	0.0029	0.03	118
Cogen 2	25	1320	3.5	85%	6,800	$707	$5.34	$0.53	0.0006	0.030	0.0029	0.03	118
Simple Cycle CT - (2 Units)	159	Unlimited	3.5	15%	11,083	$467	$1.07	$3.73	0.0006	0.090	0.0029	0.03	118
Combined Cycle CT	234	Unlimited	3.5	85%	7,517	$657	$10.67	$1.57	0.0006	0.016	0.0029	0.03	118
Geothermal	50	300	3	85%	10,000	$2,145	$15.00	$2.00	0.00	0.000	0.00	0.00	0
Wind	50	60	2	27%	0	$1,000	$9.50	$16.81	0.00	0.000	0.00	0.00	0
Pumped Storage	200	400	5	30%	12,821	$800	$13.00	$0.00	0.10	0.380	0.10	0.11	206
UTAH:													
Cogen 1	39	39	3.5	85%	5,500	$1,380	$5.34	$0.53	0.0006	0.030	0.0029	0.03	118
Cogen 2	21	420	3.5	85%	6,800	$831	$5.34	$0.53	0.0006	0.030	0.0029	0.03	118
Simple Cycle CT - (2 Units)	135	Unlimited	3.5	15%	11,083	$549	$1.07	$3.73	0.0006	0.090	0.0029	0.03	118
Combined Cycle CT	198	Unlimited	3.5	85%	7,517	$770	$10.67	$1.57	0.0006	0.016	0.0029	0.03	118
Repower Gadsby - Incremental	Varies	320	3.5	85%	5,039	$827	$2.13	$0.31	0.0006	0.016	0.0029	0.03	118
Repower Gadsby - Non-Incre.	Varies	566	3.5	85%	7,846	$467	$10.00	$1.00	0.0006	0.016	0.0029	0.03	118
PC - Hunter 4 - Extension Unit	400	Unlimited	6.5	85%	10,062	$1,483	$32.39	$0.45	0.05	0.100	0.0150	0.11	206
IGCC - Hunter 4 or Generic	262	Unlimited	6	85%	8,400	$1,735	$30.35	$2.13	0.01	0.070	0.0150	0.04	206
PC/SCR - Generic Site (2 Units)	400	Unlimited	6.5	85%	10,062	$1,694	$32.39	$0.45	0.05	0.100	0.0150	0.11	206
Geothermal	50	300	3	85%	10,000	$2,145	$15.00	$2.00	0.00	0.000	0.00	0.00	0
CAES Plant	340	340	3.5	30%	12,700	$675	$4.32	$1.10	0.07	0.281	0.07	0.08	176
Pumped Storage	200	200	5	30%	12,821	$785	$13.00	$0.00	0.10	0.380	0.10	0.11	206
Solar	100	Unlimited	5	63%	0	$4,283	$49.40	$0.00	0.00	0.000	0.00	0.00	0
Wind	50	50	3	30%	0	$1,000	$9.50	$16.81	0.00	0.000	0.00	0.00	0
WYO:													
Simple Cycle CT - (2 Units)	124	Unlimited	3.5	15%	11,083	$594	$1.07	$3.73	0.0006	0.090	0.0029	0.03	118
Combined Cycle CT	182	Unlimited	3.5	85%	7,517	$832	$10.67	$1.57	0.0006	0.016	0.0029	0.03	118
PC - Wyodak 2 - Extension	325	Unlimited	6.5	85%	11,900	$1,527	$32.39	$0.45	0.05	0.100	0.0150	0.11	206
IGCC - Wyodak 2 or Generic	262	Unlimited	6	85%	8,400	$1,710	$30.35	$2.13	0.01	0.070	0.0150	0.04	208
PC - Generic (2 Units)	325	Unlimited	6.5	85%	10,758	$1,735	$32.39	$0.45	0.05	0.100	0.0150	0.11	208
Wind	50	430	2	33%	0	$1,000	$9.50	$16.81	0.00	0.000	0.00	0.00	0

Notes: All Costs in 1/1/96 Dollars
Cogen Costs are RAMPP3 Costs Escalated 2 Years
Combined Cycle O&M Costs have been Escalated 2 Years to 1996 from GE Reference
All SCR O&M Costs for CC Units are Considered Variable and Reflect an Increase of 0.5 $/MWh in 1996 Dollars
IGCC O&M Reflects an Overall Cost of $8.21/MWh at the Quoted Capacity Factor in 1996
CAES Heat Rate Reflects the Use of Natural Gas at 4,700 Btu/kWh and Coal at 8,000 Btu/kWh
Pumped Storage Heat Rate is based on a .78 Plant Energy Use Efficiency
PC O&M Costs Reflect 1993 Actual Hunter Plant Costs Escalated 2 Years., FGD at 95% Removal, and SCR Costs if Applicable
Gadsby Repowering is Based on Budget Type Estimates using GE Technology
Incremental Gadsby Repowered O&M Costs based on Difference with Projected Current Configuration Gadsby 1995 Budget Escalated One Year as Compared to a Combined Cycle O&M Cost

GADSBY REPOWERING

Currently the Gadsby Plant consists of three steam boiler/steam turbine units. Unit 1 is rated at approximately 66 MW, Unit 2 is rated at approximately 75 MW, and Unit 3 is rated at approximately 105 MW. Originally these units, except Unit 1, could run on oil, gas, or coal. Environmental regulations, have limited operation to natural gas. Units 1 and 2 are just completing startup from being inactive since 1985. It is anticipated that the average annual heat rate on Unit 1 will be about 12,320 Btu/kWh, the heat rate on Unit 2 about 11,330 Btu/kWh, and the heat rate on Unit 3 about 10,946 Btu/kWh. Projected capacity factors, based on current natural gas prices and heat rates will be about 35 to 50%.

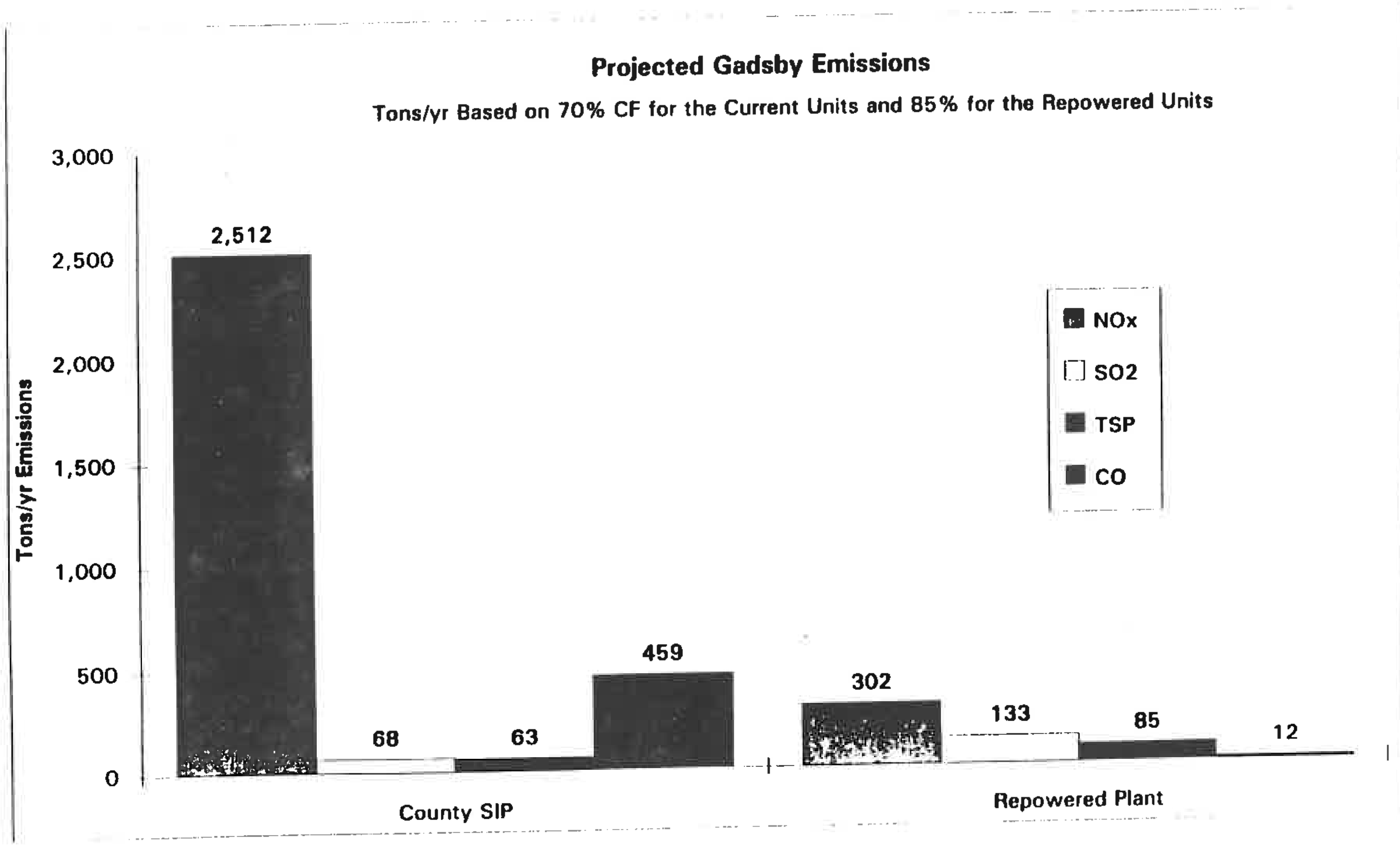
The repowering concept would convert these units into combined cycle plants. A combustion turbine would be installed for each Unit. The primary consideration is not to exceed the steam turbine exhaust flow into the condenser since, in most instances, it is expected to remove the feedwater heaters from service. Utilizing "F" type gas turbine technology, it is expected that the gas turbine capacity at 100 F ambient temperature and 4200 feet elevation will range from 125 MW to 128 MW. For Units 1 and 2 this will allow for a nice matchup with the existing steam turbines. At site rating conditions, between 58 and 65 MW of steam turbine will be utilized. During cooler ambient temperature conditions, the capacity of the gas turbines will be higher and a greater percentage of the existing steam turbines can be realized.

Unit 3's steam turbine is oversized for the a single "F" type gas turbine. A number of possibilies exist for Unit 3. A single gas turbine can be used and the steam turbine derated to about 68 MW with the possibility for duct firing added to increase the steam flow and utilize more of the steam turbine if needed. One disadvantage of this approach is that the steam turbine exhaust flow is exceeded with duct firing. Alternately two smaller gas turbines could be installed to more fully utilize the steam turbine capacity. Again the possibility exists that the higher steam flow with feedwater extraction would create a bottleneck into the condenser. Another possibility would be to apply an advanced "G" type combustion turbine such as recently announced by Westinghouse. Since this machine is so new, and no information has been received on this machine, it has not been included.

The footprint for installation of such a gas turbine/HRSG (Heat Recovery Steam Generator) would be close to the layout of a GE 7F machine. The first machine would be built for Unit 1 and would be located in the old coal yard. Steam and condensate would be transported over the main railroad track to the turbine building. After installation of the gas turbine the new steam piping would be connected on an outage. After startup of the new combined cycle arrangement, the Unit 1 boiler would be demolished along with the Unit 1 stack. The Unit 2 gas turbine could then be built on the site of the old Unit 1 boiler and stack. Subsequent installation of the new Unit 3 gas turbine would occur over the demolished Unit 2 boiler and stack. Final demolition of the Unit 3 boiler and stack would complete the project.

Natural gas would be used as the primary fuel with fuel oil available as a backup. The existing oil tanks could be refurbished to provide emergency backup. A new gas line would be required capable of delivering 120 million standard cubic feet per day of natural gas.

A principal advantage to converting Gadsby to combined cycle operation is the reduction in emissions associated with using a different technology to burn natural gas. Currently gas is burned in a boiler using low-NOx burners. Even with this state-of-the-art system, NOx emissions are still at the 100 ppm level. Burning natural gas in a combustion turbine utilizing low-NOx burners and SCR (Selective Catalytic Converters) would reduce emissions to BACT levels. Sulfur dioxide and particulate would increase in proportion to the natural gas being burned while CO_2 would increase because more fuel is being burned but, due to the efficiency increase of the combined cycle arrangement, the CO_2 emitted per MW generated would be considerably less than current operation. Enclosed is a Figure which represents the expected emissions from a repowered Gadsby Plant compared to the current Salt Lake County State Implementation Plan (SIP) which is representative of the current emission limits.


Projected Gadsby Emissions
Tons/yr Based on 70% CF for the Current Units and 85% for the Repowered Units
Tons/yr Emissions
3,000
2,500
2,000
1,500
1,000
500
0
2,512
68
63
459
302
133
85
12
County SIP
Repowered Plant
NOx
SO2
TSP
CO

11/18/94

NEW FIRM PURCHASE AND SALE CONTRACTS

P37 BPA SPRING EXCHANGE (P)
This contract provision became effective June 1, 1994 and shall continue through May 31, 2014. At Bonneville's option and notification to PacifiCorp by February 15 of each calendar year, PacifiCorp will deliver up to 50,000 MWh to Bonneville at the Hot Springs Substation during off-peak hours at a rate not to exceed 200 MW per hour during the month of March. Bonneville will return the same amount of energy delivered in March in uniform amounts during the all the off-peak hours of the following June 1 through July 15 period. Unless otherwise agreed, deliveries to PacifiCorp are to be made at Bonneville's points of delivery to PacifiCorp under the RESTATED SURPLUS FIRM CAPACITY SALE AGREEMENT.

There are no charges by either party to the other for these transactions.

P38 BPA SUMMER EXCHANGE (P)
This contract provision became effective June 1, 1994 and shall continue through May 31, 2014. One week prior to the months of June and July in each calendar year, Bonneville will give PacifiCorp notice of the amounts of energy to be stored for the following month. PacifiCorp is not required to accept in excess of 100,000 MWh per month and Bonneville may not deliver less than 25,000 MWh per month for storage. The amount of energy to be delivered to PacifiCorp for storage in each month will be delivered uniformly during all hours of that month. The energy delivered to PacifiCorp in each June and July will be returned to Bonneville in the following September, October and November of the same calendar year. The total amount of energy stored by PacifiCorp will be returned in three equal amounts during each of those months spread uniformly over each of the hours of such month. Unless otherwise agreed, deliveries to PacifiCorp are to be made at Bonneville's points of delivery to PacifiCorp under the RESTATED SURPLUS FIRM CAPACITY SALE AGREEMENT and returns to Bonneville will be made at the Hot Springs or Summer Lake Substations.

There are no charges by either party to the other for these transactions.

P39 TWWP SEASONAL EXCHANGE (P)
This contract provision became effective June 16, 1994 and will continue through March 31, 2009. As determined by PacifiCorp, The Washington Water Power Company ("TWWP") will furnish up to 50 MW to PacifiCorp at the Hot Springs Substation during the period June 16 through September 15 of each calendar year. If PacifiCorp cannot accept all of the capacity to be furnished, the balance will be furnished to PacifiCorp at the Mid-Columbia projects. Energy associated with this capacity may not exceed a load factor of 50% and may not total more than 27,600 MWh. During the period of December 1 through the last day of February of the following calendar year, PacifiCorp will furnish up to 50 MW to TWWP at the Hot Springs Substation. If PacifiCorp cannot deliver all of the capacity to be furnished, the balance will be furnished to TWWP at the Mid-Columbia projects. Energy associated with this capacity may not exceed a load factor of 50% and may not total more than 27,600 MWh.

Any differences between the amounts of energy delivered to PacifiCorp during a June 16 through September 15 period and the amounts of energy delivered to TWWP during the next following December 1 through last day of February period will be delivered by the party receiving the higher amount of energy to the other party in equal amounts during all hours of the next following month of March.

There are no charges by either party to the other for these transactions.

P40 TWWP SUMMER PURCHASE
This contract provision became effective June 16, 1994 and will continue through September 15, 2003. During the June 16 through September 15 period of each calendar year, TWWP will furnish 100 MW in 1994 and 1995 and 150 MW for the years 1996 through 2003 to PacifiCorp at the Hot Springs Substation. If PacifiCorp cannot accept all of the capacity to be furnished, the balance will be furnished to PacifiCorp at the Mid-Columbia projects. Energy associated with this capacity may neither exceed a load factor of 70% nor be less than a load factor of 10% (energy for partial months to be prorated per the number of hours in that month).

CLARK PUD INTERIM SALE
Between August 1, 1995 and July 31, 1998, unless Clark PUD elects to terminate this agreement upon the commercial operation date of its combustion turbine project, PacifiCorp will deliver 100 MW of Base Capacity at a load factor of 100%. Energy will be delivered to Bonneville at the Troutdale Substation for delivery to Clark PUD points of delivery by separate contract with Bonneville. (Note: Clark PUD has indicated it will not exercise its option for Winter Capacity.)

CLARK PUD STORAGE AND INTEGRATION SERVICES

Service to Clark PUD will commence upon the commercial operation date of Clark PUD's combustion turbine project and continue through the tenth anniversary of that date. PacifiCorp's services to Clark PUD will include dispatching, storage, marketing, spinning reserves, load factoring, and load following. Because of the complexity of the services provided, they have not been included in the RAMPP modeling.

WOEC FULL REQUIREMENTS SERVICE

Commencing on a date to be determined by WOEC, but no earlier than July 1, 1995, PacifiCorp will supply all of WOEC's capacity and energy requirements for an initial three year period at prices as stated in the agreement. Upon agreement of the parties upon pricing in any subsequent periods, this contract could be extended to no later than September 30, 1995. Deliveries to WOEC will be made, or caused to be made, to WOEC's existing delivery points form PacifiCorp's system.

CITY OF REDDING PSA

Between June 1, 1994 and May 31, 2014, PacifiCorp will supply 50 MW of Firm Capacity to Redding at COB on the AC Intertie. Firm Energy associated with Firm Capacity will be purchased by Redding at a minimum load factor of 70% and a maximum load factor of 85% each month.

Prices for Firm Capacity and Firm Energy are fixed in the initial years of the contract and then convert to a Resource Pool pricing methodology for the remaining term of the agreement.

RAMPP-4 DSR Development

RAMPP-4 DSR Modeling Goal:

Use IPM to optimize annual penetration rates for programs- especially retrofit programs.

(Our objective for lost-opportunity resources has been to capture all cost-effective resources)

Previously Planned Approach:

Use IPM model to optimize annual program penetration rates using annual minimum and maximum DSR percentages and the unconstrained resource potential for each program. The minimum and maximum DSR percentage were intended to act as boundaries on the program resource.

Problem with the Planned Approach:

After testing the above approach, we learned that current IPM model structure can not optimize annual penetration rates for a given program. IPM model chose either zero or 100 percent of the program. The model did not ramp-up the penetration rate for the program. The model can delay the acquision start-up, but does not ramp-up.

Solutions Investigated:

1) Change IPM code so that it could optimize annual penetration rates.
This option requires substantial code change. It would delay RAMPP-4 time table.

2) Approximate optimization of penetration rates by giving IPM supply curves for each DSR resource option.

The Proposed Approach:

1) Disaggregate technical potential options (the supply curves) into mutually exclusive incremental resource bundles. Each bundle would be characterized by a MWH potential and an average levelized cost.

2) Apply the percentage for each bundle of technical potential to market resource potential (prorate market potential by bundle). Calculate program cost for each market potential bundle

3) Specify an initial penetration rate for market potential

PacifiCorp
RAMPP-4 DSM Technical Analysis Process

DSM analysis process consisted of the following steps:

1: Estimating cost and savings for each market sector
2: Establishing the resource bundles
3: Screening each resource bundle
4: Estimating size of market for each market sector
5: Estimating initial penetration rates for each market sector
6: Estimating size and cost of each resource bundle for input to IPM
7: Adjusting the cost thresholds and penetration rates based on IPM results

The following tables show penetration rates, program costs, IPM selected resource bundles. Level of DSM selected under various key assumptions and the state by state acquisition targets.

More detailed information is available in the DSM Technical Appendix in an Excel 5.0 format. It can be obtained by contacting Julie Alonso at 503-464-5620.

Table 1
Market Penetration Rates

MARKET	1996	1997	1998	2000	2005	2010	2016
Commercial New Construction	75%	85%	85%	85%	85%	85%	85%
Commercial Retrofit	4%	4%	4%	4%	4%	4%	4%
Industrial	4%	4%	4%	4%	4%	4%	4%
Irrigation	2%	2%	2%	2%	2%	2%	2%
Residential Programs- Existing Stock							
Compact fluorescent & water saving measures	4%	4%	4%	4%	4%	4%	4%
Residential Programs- New & Replacement							
Res. appliance-New- CFL & water saving measures	30%	40%	50%	75%	75%	75%	75%
Res. appliance- SERP *	5%	6%	6%	7%	10%	12%	15%
Res. appliance-H.axis Washers *	1%	2%	3%	5%	10%	15%	21%

* Percent of annual replacement. Includes stock replacement and new additions.

Table 2
Program Cost by Resource Bundle

	Admin. Cost levelized Mills/Kwh Gross savings	Total Resource Cost Mills/kwh	Program LIFE Years	Initial Cost Cost $/mwh	PV 50 yr. Cycle $/mwh IPM input
Residential Existing Appliance Market					
Bundle 1- Water savings measures	8	-15	15	-156	0
Bundle 2- Compact FL measure	3	16	7	93	522
Residential weatherization Market					
Home comfort (Bundle 1)	7	83	23	1102	1451
low income + bidding (Bundle 2)	10	51	19	611	883
SGC retro (Bundle 3)	15	53	23	700	922
Residential New Construction Market	5	22	45	388	388
Residential New Appliance Market					
Water saving and CFL measures	4	-16	15	-163	0
SERP refrigerators	0	7	19	80	116
Horizontal Axis Washing machine	1	-107	12	-942	0
Commercial New Construction Market					
FINANSWER- 40 mill cut off	3	25	30	371	427
EF 12,000- 35 mill cut off	2	25	30	380	436
Commercial Retrofit market					
Bundle 1, 0-25 cut off	3	25	30	382	439
Bundle 2, 25-27	2	30	30	459	527
Bundle 3, 27-29	1	31	30	474	545
Bundle 4, 29-40	1	39	30	593	682
Industrial Market					
Bundle 1, 13 mill cut off	4	13	15	138	238
Bundle 2, 21 mill cut off	3	21	15	212	367
Bundle 3, 23 mill cut off	2	24	15	245	424
Bundle 4, 27 mill cutoff	2	25	15	261	451
IRRIGATION	5	38	15	386	597
Residential Water heater Load Control	9	9	20	289	289

Table 3
IPM model selected resource bundles
Timing of DSM Acquisition - Case with 15% Credit for DSM

Program Description	1996	1997	1998	1999	2000	2001
01-COM. FNSWR- OWC	100	0	0	0	0	0
02-COM. FNSWR- UT	100	0	0	0	0	0
03-COM. FNSWR- WY	100	0	0	0	0	0
04-COM 12000 -OWC	100	0	0	0	0	0
05-COM 12000 -UT	100	0	0	0	0	0
06-COM 12000 -WY	100	0	0	0	0	0
07-COM RTRO-B1-OWC	100	0	0	0	0	0
08-COM RTRO-B1-UT	100	0	0	0	0	0
09-COM RTRO-B1-WY	100	0	0	0	0	0
10-COM RTRO-B2-OWC	100	0	0	0	0	0
11-COM RTRO-B2-UT	0	0	0	0	0	0
12-COM RTRO-B2-WY	0	0	0	0	0	0
13 COM RTRO-B3-OWC	0	0	0	0	0	0
14-COM RTRO-B3-UT	100	0	0	0	0	0
15-COM RTRO-B3-WY	100	0	0	0	0	0
16-COM RTRO-B4-OWC	0	0	100	0	0	0
17-COM RTRO-B4-UT	0	0	0	100	0	0
18-COM RTRO-B4-WY	0	0	100	0	0	0
19-IND-B1-OWC	100	0	0	0	0	0
20-IND-B1-UT	100	0	0	0	0	0
21-IND-B1-WY	100	0	0	0	0	0
22-IND-B2-OWC	100	0	0	0	0	0
23-IND-B2-UT	100	0	0	0	0	0
24-IND-B2-WY	100	0	0	0	0	0
25-IND-B3-OWC	100	0	0	0	0	0
26-IND-B3-UT	100	0	0	0	0	0
27-IND-B3-WY	100	0	0	0	0	0
28-IND-B4-OWC	100	0	0	0	0	0
29-IND-B4-UT	100	0	0	0	0	0
30-IND-B4-WY	100	0	0	0	0	0
31-IRRIGATION-OWC	100	0	0	0	0	0
32-IRRIGATION-UT	0	0	0	0	0	0
33-SGCENTS-OWC	100	0	0	0	0	0
34-SGCENTS-UT	0	0	0	0	100	0
35-SGCENTS-WY	0	0	0	0	0	100
36-RES. WX-B1-OWC	0	0	0	0	0	0
37-RES. WX-B1-UT	0	0	0	0	0	0
38-RES. WX-B2-OWC	0	0	0	0	0	0
39-RES. WX-B2-UT	0	0	0	0	0	0
40-RES. WX-B3-OWC	0	0	0	0	0	0
41-RES. WX-B3-UT	0	0	0	0	0	0
42-AP.RTRO-B1-OWC	100	0	0	0	0	0
43-AP.RTRO-B1-UT	100	0	0	0	0	0
44-AP.RTRO-B1-WY	100	0	0	0	0	0
45-AP.RTRO-B2-OWC	100	0	0	0	0	0
46-AP.RTRO-B2-UT	100	0	0	0	0	0
47-AP.RTRO-B2-WY	100	0	0	0	0	0
48-AP.New-B1-OWC	100	0	0	0	0	0
49-AP.New-B1-UT	100	0	0	0	0	0
50-AP.New-B1-WY	100	0	0	0	0	0
51-AP.New-B2-OWC	100	0	0	0	0	0
52-AP.New-B2-UT	100	0	0	0	0	0
53-AP.New-B2-WY	100	0	0	0	0	0
54-AP.New-B3-OWC	100	0	0	0	0	0
55-AP.New-B3-UT	100	0	0	0	0	0
56-AP.New-B3-WY	100	0	0	0	0	0
57-WH LD CTRL-OWC	0	0	0	0	0	0

Table 4
IPM model selected resource bundles
MWa - Case with 15% Credit for DSR

Description	1996	1997	1998	2000	2005	2011	2015
01-COM. FNSWR- OWC	2.0	4.8	7.7	13.8	29.6	47.1	57.2
02-COM. FNSWR- UT	1.4	3.0	4.7	8.2	16.3	25.0	29.8
03-COM. FNSWR- WY	0.1	0.2	0.3	0.5	0.9	1.5	1.8
04-COM 12000 -OWC	0.3	0.6	0.9	1.5	3.1	4.6	5.3
05-COM 12000 -UT	0.6	1.3	2.0	3.5	6.9	10.7	12.9
06-COM 12000 -WY	0.2	0.4	0.7	1.2	2.5	3.9	4.7
07-COM RTRO-B1-OWC	1.8	3.6	5.4	8.9	17.8	28.6	35.3
08-COM RTRO-B1-UT	1.5	2.9	4.3	7.2	14.4	23.1	28.6
09-COM RTRO-B1-WY	0.4	0.7	1.1	1.8	3.7	5.9	7.2
10-COM RTRO-B2-OWC	0.2	0.4	0.7	1.1	2.2	3.5	4.3
11-COM RTRO-B2-UT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-COM RTRO-B2-WY	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13 COM RTRO-B3-OWC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14-COM RTRO-B3-UT	0.4	0.8	1.1	1.9	3.8	6.1	7.5
15-COM RTRO-B3-WY	0.1	0.2	0.2	0.4	0.7	1.2	1.5
16-COM RTRO-B4-OWC	0.0	0.0	2.1	6.2	16.4	28.8	36.9
17-COM RTRO-B4-UT	0.0	0.0	0.0	4.4	15.2	28.4	37.0
18-COM RTRO-B4-WY	0.0	0.0	0.5	1.5	4.1	7.1	9.2
19-IND-B1-OWC	1.7	3.5	5.2	8.6	17.2	27.6	34.1
20-IND-B1-UT	2.4	4.7	7.1	11.8	23.6	37.8	46.7
21-IND-B1-WY	1.5	2.9	4.4	7.3	14.5	23.2	28.6
22-IND-B2-OWC	0.9	1.8	2.7	4.6	9.1	14.6	18.0
23-IND-B2-UT	1.5	3.0	4.5	7.6	15.1	24.2	29.9
24-IND-B2-WY	0.7	1.4	2.1	3.6	7.1	11.3	14.0
25-IND-B3-OWC	0.8	1.6	2.4	3.9	7.8	12.5	15.4
26-IND-B3-UT	1.3	2.6	3.9	6.5	12.9	20.7	25.6
27-IND-B3-WY	0.6	1.2	1.8	3.0	6.1	9.7	12.0
28-IND-B4-OWC	0.2	0.3	0.5	0.9	1.7	2.7	3.3
29-IND-B4-UT	0.3	0.6	0.9	1.6	3.1	5.0	6.2
30-IND-B4-WY	0.1	0.3	0.4	0.7	1.3	2.1	2.6
31-IRRIGATION-OWC	0.3	0.5	0.8	1.3	2.6	4.2	5.1
32-IRRIGATION-UT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33-SGCENTS-OWC	0.1	0.2	0.3	0.7	2.1	3.8	4.8
34-SGCENTS-UT	0.0	0.0	0.0	0.0	0.2	0.5	0.7
35-SGCENTS-WY	0.0	0.0	0.0	0.0	0.4	1.5	2.6
36-RES. WX-B1-OWC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37-RES. WX-B1-UT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38-RES. WX-B2-OWC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39-RES. WX-B2-UT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40-RES. WX-B3-OWC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41-RES. WX-B3-UT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42-AP.RTRO-B1-OWC	0.4	0.8	1.1	1.7	2.6	2.8	2.9
43-AP.RTRO-B1-UT	0.3	0.6	0.8	1.2	1.9	2.0	2.0
44-AP.RTRO-B1-WY	0.1	0.1	0.2	0.3	0.5	0.5	0.5
45-AP.RTRO-B2-OWC	0.4	0.7	1.1	1.8	3.5	5.5	6.7
46-AP.RTRO-B2-UT	0.4	0.8	1.2	2.0	4.0	6.2	7.6
47-AP.RTRO-B2-WY	0.3	0.7	1.0	1.7	3.3	5.2	6.3
48-AP.New-B1-OWC	0.2	0.5	0.9	2.2	6.3	10.0	11.6
49-AP.New-B1-UT	0.1	0.2	0.3	0.9	3.4	7.1	9.0
50-AP.New-B1-WY	0.0	0.1	0.2	0.4	1.3	2.1	2.3
51-AP.New-B2-OWC	0.0	0.1	0.1	0.2	0.4	0.8	1.1
52-AP.New-B2-UT	0.0	0.1	0.1	0.2	0.5	0.9	1.3
53-AP.New-B2-WY	0.0	0.0	0.0	0.0	0.1	0.1	0.2
54-AP.New-B3-OWC	0.0	0.0	0.1	0.1	0.5	0.7	0.8
55-AP.New-B3-UT	0.0	0.0	0.1	0.1	0.5	0.7	0.9
56-AP.New-B3-WY	0.0	0.0	0.0	0.0	0.0	0.1	0.1
57-WH LD CTRL-OWC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total DSM Programs	23	48	76	137	291	471	582

DSM Selected by Year — Energy MWa

Study Title	Case Number	Study Year 1996	1997	1998	1999	2000
No DSM	11	0	0	0	0	0
Med Low Load - Med Gas	21	5.4	10.9	16.4	22.1	28
No Summer Season	4	12.9	27.1	44.3	62.1	83.2
15% Conservation Disadvantage	14	13.7	30.9	49.4	68.3	89.6
Med Load - Low Gas	31	16.9	35.7	55.1	74.9	95.1
Extension of Loads & DSM to 2045	66	15.9	35.6	56.7	78.4	101.8
500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	47	16.9	37.1	58.8	81.6	106.2
250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	44	17.6	38.7	61.3	85.4	110.6
500 MW Plant in 1999 - Medium Non-Firm Market Prices	48	18.6	40.5	63	87.3	112.7
25% Lower Non-Firm Market Prices	42	19.1	41	63.6	87.7	112.9
500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	49	19.2	41.2	63.8	88.1	113.5
Renewables at 35% of Capital Cost	61	19.4	41.3	64.3	89.1	114.3
250 MW Plant in 1999 - Medium Non-Firm Market Prices	45	19.4	41.3	65.2	90.2	115.7
Extension of All Modeling to 2045	67	20.4	42.4	66.3	90.7	116.2
Base Case	1	20.5	42.4	66.5	91.5	117
Added Transmission - Utah to OWC	59	20.5	42.4	66.5	91.5	117
Added Transmission - Bridger to OWC	58	20.2	42.1	66.6	91.6	117.1
250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	46	20.5	42.7	66.7	91.7	117.1
Underbuild - 25% Lower Non-Firm Market Prices	50	20.8	42.8	67.5	92.4	117.8
25% Higher Non-Firm Market Prices	43	20.5	44	68.8	93.9	119.5
No Turbine Upgrades	5	20.8	45	69.7	95.1	121
Without Hermiston	6	20.9	45.1	69.9	95.4	121.4
Med Load High Gas Without Hermiston	7	22.1	46.2	71.7	97.6	124.1
Resource Lumpiness	41	23	47.1	72.5	98.4	124.7
Limited Gas (500 MW) at Med Esc	32	23	47.5	72.7	100.3	128.4
Med Load - High Gas	33	23	47.6	72.8	101	129.5
Med Load High Gas Without Hermiston	7	23	47.6	72.8	101	129.5
Low Environmental Adders	71	23.1	47.7	73.1	98.8	124.9
Underbuild - Medium Non-Firm Market Prices	51	23.4	48	73.3	98.8	124.8
Underbuild - 25% Higher Non-Firm Market Prices	52	23.4	48	73.3	98.8	124.8
High Gas - with Medium Non-firm Market Prices	34	23	47.5	75.3	105.6	136.4
15% Conservation Advantage	13	23.4	48	75.9	106.2	137
Medium Environmental Adders	72	26.2	53.6	81.6	110	138.9
20% Conservation Advantage	12	23.5	52.9	83.1	113.5	144.4
High Environmental Adders	73	28.3	57.7	87.8	118.3	149.2
Med High Load - Med Gas	22	29.4	63.1	97.6	132.5	168

State by State Program Goals for DSM inCase 13

RAMPP-4 Program goals	State	1996	1997	1998	1999	2000	2001
Commercial New	CALIFORNIA	932	945	1692	1747	1814	1845
Commercial Retrofit	CALIFORNIA	403	403	1409	1409	1409	1409
Industrial	CALIFORNIA	316	316	316	316	316	316
Irrigation	CALIFORNIA	562	562	562	562	562	562
Residential New	CALIFORNIA	158	208	242	278	322	405
Residential Retrofit	CALIFORNIA	1449	1613	1788	1990	2407	2650
Total	CALIFORNIA	3820	4046	6009	6302	6831	7188
	Program Goal (MWH)	7639	8093	12019	12604	13661	14376
	Program Goal (MWa)	0.87	0.92	1.37	1.44	1.56	1.64
Commercial New	IDAHO UPL	324	358	387	386	420	412
Commercial Retrofit	IDAHO UPL	1144	1144	1144	1733	1733	1733
Industrial	IDAHO UPL	5381	5381	5381	5381	5381	5381
Irrigation	IDAHO UPL	0	0	0	0	0	0
Residential New	IDAHO UPL	65	84	101	140	186	211
Residential Retrofit	IDAHO UPL	1084	1128	1183	1298	1499	1523
Total	IDAHO UPL	7998	8096	8197	8937	9220	9260
	Program Goal (MWH)	15997	16191	16394	17875	18439	18520
	Program Goal (MWa)	1.83	1.85	1.87	2.04	2.10	2.11
Commercial New	MONTANA	3290	3849	3257	3232	3231	3214
Commercial Retrofit	MONTANA	517	517	1005	1005	1005	1005
Industrial	MONTANA	969	969	969	969	969	969
Irrigation	MONTANA	0	0	0	0	0	0
Residential New	MONTANA	33	38	44	52	56	79
Residential Retrofit	MONTANA	801	855	916	1012	1155	1244
Total	MONTANA	5611	6229	6191	6270	6416	6511
	Program Goal (MWH)	11221	12458	12382	12540	12831	13023
	Program Goal (MWa)	1.28	1.42	1.41	1.43	1.46	1.49

State by State Program Goals for DSM inCase 13

RAMPP-4 Program goals	State	1996	1997	1998	1999	2000	2001
Commercial New	OREGON	11623	16711	18251	18675	19487	19811
Commercial Retrofit	OREGON	11240	11240	22157	22157	22157	22157
Industrial	OREGON	20700	20700	20700	20700	20700	20700
Irrigation	OREGON	1493	1493	1493	1493	1493	1493
Residential New	OREGON	364	471	560	581	675	854
Residential Retrofit	OREGON	4019	4137	4264	4391	4691	4956
Total	OREGON	49439	54752	67425	67997	69203	69971
	Program Goal (MWH)	98878	109504	134850	135995	138406	139942
	Program Goal (MWa)	11.29	12.50	15.39	15.52	15.80	15.98
Commercial New	UTAH	14255	16431	18354	18030	17707	17352
Commercial Retrofit	UTAH	13111	13111	13111	29751	29751	29751
Industrial	UTAH	33689	33689	33689	33689	33689	33689
Irrigation	UTAH	0	0	0	0	0	0
Residential New	UTAH	0	0	0	0	0	0
Residential Retrofit	UTAH	5224	5325	5379	5961	6735	6930
Total	UTAH	66278	68556	70533	87431	87882	87723
	Program Goal (MWH)	132556	137112	141066	174861	175764	175445
	Program Goal (MWa)	15.13	15.65	16.10	19.96	20.06	20.03
Commercial New	WASHINGTON	2129	2371	2681	2695	2702	2675
Commercial Retrofit	WASHINGTON	3681	3681	7539	7539	7539	7539
Industrial	WASHINGTON	6356	6356	6356	6356	6356	6356
Irrigation	WASHINGTON	0	0	0	0	0	0
Residential New	WASHINGTON	160	197	229	508	607	670
Residential Retrofit	WASHINGTON	3841	4014	4221	4885	5561	5597
Total	WASHINGTON	16169	16620	21027	21984	22764	22837
	Program Goal (MWH)	32337	33240	42054	43968	45529	45674
	Program Goal (MWa)	3.69	3.79	4.80	5.02	5.20	5.21

State by State Program Goals for DSM inCase 13

RAMPP-4 Program goals	State	1996	1997	1998	1999	2000	2001
Commercial New	WYOMING PPL	2126	2422	2755	2805	2867	2877
Commercial Retrofit	WYOMING PPL	3482	3482	7518	7518	7518	7518
Industrial	WYOMING PPL	22853	22853	22853	22853	22853	22853
Irrigation	WYOMING PPL	0	0	0	0	0	0
Residential New	WYOMING PPL	0	0	0	0	0	873
Residential Retrofit	WYOMING PPL	1466	1560	1683	1798	2122	2250
Total	WYOMING PPL	29927	30317	34808	34973	35359	36369
	Program Goal (MWH)	59853	60633	69616	69946	70718	72738
	Program Goal (MWa)	6.83	6.92	7.95	7.98	8.07	8.30
Commercial New	WYOMING UPL	1164	1030	1163	1366	1497	1386
Commercial Retrofit	WYOMING UPL	184	184	222	222	222	222
Industrial	WYOMING UPL	4224	4224	4224	4224	4224	4224
Irrigation	WYOMING UPL	0	0	0	0	0	0
Residential New	WYOMING UPL	0	0	0	0	0	95
Residential Retrofit	WYOMING UPL	184	195	209	215	235	240
Total	WYOMING UPL	5755	5632	5818	6027	6178	6166
	Program Goal (MWH)	11510	11265	11637	12053	12356	12333
	Program Goal (MWa)	1.31	1.29	1.33	1.38	1.41	1.41

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Potential Resources
Impact of Updated Fuel Prices

Sorted by Unit Name

Short Name	Description	Current Prices (11/1/95) Energy Cost in 2003 (1996$) 1st Year ¢/MMBTU	Levelized ¢/MMBTU	Levelized Mills/kWh	Total Resource Cost	RAMPP-4 Costs Energy Cost in 2003 (1996$) 1st Year ¢/MMBTU	Levelized ¢/MMBTU	Levelized Mills/kWh	Total Resource Cost	Difference Energy Cost in 2003 (1996$) 1st Year ¢/MMBTU	Levelized ¢/MMBTU	Levelized Mills/kWh	Total Resource Cost
CPU	Summer Purch $6/Year	149.0	168.3	17.76	26.99	190.9	225.9	23.85	33.08	-41.9	-57.6	-6.08	-6.08
OC1	OWC Cogen 1	174.0	193.3	8.31	23.81	226.0	261.0	11.22	26.72	-52.0	-67.7	-2.91	-2.91
OC2	OWC Cogen 2	174.0	193.3	11.98	22.36	226.0	261.0	16.18	26.56	-52.0	-67.7	-4.20	-4.20
OCC	OWC Combined Cycle	174.0	193.3	12.53	24.05	226.0	261.0	18.71	30.23	-52.0	-67.7	-6.18	-6.18
OCT	OWC Simple Cycle CT	149.0	168.3	17.76	68.00	190.9	225.9	23.85	91.92	-41.9	-57.6	-6.08	-23.91
OET	OWC Bridger Trans L	97.1	97.1	8.59	20.44	97.1	97.1	8.59	20.44	0.0	0.0	0.00	0.00
OEV	OWC Htr/OWC Trans L	104.1	104.1	9.56	23.49	104.1	104.1	9.56	23.49	0.0	0.0	0.00	0.00
OGT	OWC Geothermal	107.3	107.3	10.73	41.66	107.3	107.3	10.73	41.66	0.0	0.0	0.00	0.00
OPS	OWC Pump Storage	0.0	0.0	0.00	32.12	0.0	0.0	0.00	32.12	0.0	0.0	0.00	0.00
OW1	OWC Wind Non-Firm	0.0	0.0	0.00	49.18	0.0	0.0	0.00	49.18	0.0	0.0	0.00	0.00
OW2	OWC Wind Firm	0.0	0.0	0.00	56.99	0.0	0.0	0.00	56.99	0.0	0.0	0.00	0.00
UC1	Utah Cogen 1	170.1	190.5	8.19	26.19	200.2	235.2	10.11	28.12	-30.1	-44.7	-1.92	-1.92
UC2	Utah Cogen 2	170.1	190.5	11.81	23.69	200.2	235.2	14.58	26.47	-30.1	-44.7	-2.77	-2.77
UCC	Utah Combined Cycle	170.1	190.5	12.35	25.61	200.2	235.2	16.86	30.12	-30.1	-44.7	-4.51	-4.51
UCT	Utah Simple Cycle CT	151.9	172.4	18.19	82.01	184.7	219.7	23.19	88.22	-32.8	-47.4	-5.00	-6.22
UCY	Utah IGCC Hunter 4	91.8	100.1	7.99	35.86	91.8	100.1	7.99	35.86	0.0	0.0	0.00	0.00
UCZ	Utah IGCC CT	106.7	116.3	9.28	38.13	106.7	116.3	9.28	38.13	0.0	0.0	0.00	0.00
UD1	Utah Gadsby Repower	170.1	190.5	9.60	21.08	200.2	235.2	11.85	23.34	-30.1	-44.7	-2.25	-2.25
UG1	Utah PC Hunter 4 $20/Ton	91.8	100.1	9.59	31.62	91.8	100.1	9.59	31.62	0.0	0.0	0.00	0.00
UG2	Utah Coal $23.25/Ton	106.7	116.3	11.15	36.45	106.7	116.3	11.15	36.45	0.0	0.0	0.00	0.00
UG3	Utah Coal $27.00/Ton	123.9	135.1	12.95	38.25	123.9	135.1	12.95	38.25	0.0	0.0	0.00	0.00
UGT	Utah Geothermal	107.3	107.3	10.73	41.66	107.3	107.3	10.73	41.66	0.0	0.0	0.00	0.00
UPC	Utah Compressed Air	170.1	190.5	8.95	43.83	200.2	235.2	11.06	45.94	-30.1	-44.7	-2.10	-2.10
UPS	Utah Pumped Storage	0.0	0.0	0.00	31.65	0.0	0.0	0.00	31.65	0.0	0.0	0.00	0.00
UW1	Utah Wind Non-firm	0.0	0.0	0.00	38.78	0.0	0.0	0.00	38.78	0.0	0.0	0.00	0.00
UW2	Utah Wind Firm	0.0	0.0	0.00	48.25	0.0	0.0	0.00	48.25	0.0	0.0	0.00	0.00
WCC	Wyo Combined Cycle	170.1	190.5	12.35	26.36	200.2	235.2	16.86	30.87	-30.1	-44.7	-4.51	-4.51
WCT	Wyo Simple Cycle CT	151.9	172.4	18.19	85.15	184.7	219.7	23.19	91.37	-32.8	-47.4	-5.00	-6.22
WCY	Wyo IGCC Wyodak 2	39.8	41.1	3.28	36.44	39.8	41.1	3.28	36.44	0.0	0.0	0.00	0.00
WCZ	Wyo IGCC CT	41.0	42.4	3.38	36.54	41.0	42.4	3.38	36.54	0.0	0.0	0.00	0.00
WG1	Wyo PC Wyodak 2	39.8	41.1	4.65	32.35	39.8	41.1	4.65	32.35	0.0	0.0	0.00	0.00
WG2	Wyo Coal $6.70/Ton	41.0	42.4	4.34	34.38	41.0	42.4	4.34	34.38	0.0	0.0	0.00	0.00
WW1	Wyo Wind Non-firm	0.0	0.0	0.00	38.78	0.0	0.0	0.00	38.78	0.0	0.0	0.00	0.00
WW2	Wyo Wind Firm	0.0	0.0	0.00	48.40	0.0	0.0	0.00	48.40	0.0	0.0	0.00	0.00

Potential Resources
Impact of Updated Fuel Prices

Sorted by Total Resource Cost

Short Name	Description	Current Prices (11/1/95) Energy Cost in 2003 (1996$) 1st Year ¢/MMBTU	Current Prices Levelized ¢/MMBTU	Current Prices Levelized Mills/kWh	Current Prices Total Resource Cost	RAMPP-4 Costs Energy Cost in 2003 (1996$) 1st Year ¢/MMBTU	RAMPP-4 Costs Levelized ¢/MMBTU	RAMPP-4 Costs Levelized Mills/kWh	RAMPP-4 Costs Total Resource Cost	Difference Energy Cost in 2003 (1996$) 1st Year ¢/MMBTU	Difference Levelized ¢/MMBTU	Difference Levelized Mills/kWh	Difference Total Resource Cost
UD1	Utah Gadsby Repower	170.1	190.5	9.60	21.08	200.2	235.2	11.85	23.34	-30.1	-44.7	-2.25	-2.25
UC2	Utah Cogen 2	170.1	190.5	11.81	23.69	200.2	235.2	14.58	26.47	-30.1	-44.7	-2.77	-2.77
OC2	OWC Cogen 2	174.0	193.3	11.98	22.36	226.0	261.0	16.18	26.56	-52.0	-67.7	-4.20	-4.20
OC1	OWC Cogen 1	174.0	193.3	8.31	23.81	226.0	261.0	11.22	26.72	-52.0	-67.7	-2.91	-2.91
UC1	Utah Cogen 1	170.1	190.5	8.19	26.19	200.2	235.2	10.11	28.12	-30.1	-44.7	-1.92	-1.92
UCC	Utah Combined Cycle	170.1	190.5	12.35	25.61	200.2	235.2	16.86	30.12	-30.1	-44.7	-4.51	-4.51
OCC	OWC Combined Cycle	174.0	193.3	12.53	24.05	226.0	261.0	18.71	30.23	-52.0	-67.7	-6.18	-6.18
WCC	Wyo Combined Cycle	170.1	190.5	12.35	26.36	200.2	235.2	16.86	30.87	-30.1	-44.7	-4.51	-4.51
UG1	Utah PC Hunter 4 $20/Ton	91.8	100.1	9.59	31.62	91.8	100.1	9.59	31.62	0.0	0.0	0.00	0.00
WG1	Wyo PC Wyodak 2	39.8	41.1	4.65	32.35	39.8	41.1	4.65	32.35	0.0	0.0	0.00	0.00
WG2	Wyo Coal $6.70/Ton	41.0	42.4	4.34	34.38	41.0	42.4	4.34	34.38	0.0	0.0	0.00	0.00
UCY	Utah IGCC Hunter 4	91.8	100.1	7.99	35.86	91.8	100.1	7.99	35.86	0.0	0.0	0.00	0.00
UG2	Utah Coal $23.25/Ton	106.7	116.3	11.15	36.45	106.7	116.3	11.15	36.45	0.0	0.0	0.00	0.00
WCY	Wyo IGCC Wyodak 2	39.8	41.1	3.28	36.44	39.8	41.1	3.28	36.44	0.0	0.0	0.00	0.00
WCZ	Wyo IGCC CT	41.0	42.4	3.38	36.54	41.0	42.4	3.38	36.54	0.0	0.0	0.00	0.00
UCZ	Utah IGCC CT	106.7	116.3	9.28	38.13	106.7	116.3	9.28	38.13	0.0	0.0	0.00	0.00
UG3	Utah Coal $27.00/Ton	123.9	135.1	12.95	38.25	123.9	135.1	12.95	38.25	0.0	0.0	0.00	0.00
UW1	Utah Wind Non-firm	0.0	0.0	0.00	38.78	0.0	0.0	0.00	38.78	0.0	0.0	0.00	0.00
WW1	Wyo Wind Non-firm	0.0	0.0	0.00	38.78	0.0	0.0	0.00	38.78	0.0	0.0	0.00	0.00
OGT	OWC Geothermal	0.0	107.3	10.73	41.66	0.0	107.3	10.73	41.66	0.0	0.0	0.00	0.00
UGT	Utah Geothermal	107.3	107.3	10.73	41.66	107.3	107.3	10.73	41.66	0.0	0.0	0.00	0.00
UW2	Utah Wind Firm	0.0	0.0	0.00	48.25	0.0	0.0	0.00	48.25	0.0	0.0	0.00	0.00
WW2	Wyo Wind Firm	0.0	0.0	0.00	48.40	0.0	0.0	0.00	48.40	0.0	0.0	0.00	0.00
OW1	OWC Wind Non-Firm	0.0	0.0	0.00	49.18	0.0	0.0	0.00	49.18	0.0	0.0	0.00	0.00
OW2	OWC Wind Firm	0.0	0.0	0.00	56.99	0.0	0.0	0.00	56.99	0.0	0.0	0.00	0.00
UCT	Utah Simple Cycle CT	151.9	172.4	18.19	82.01	184.7	219.7	23.19	88.22	-32.8	-47.4	-5.00	-6.22
WCT	Wyo Simple Cycle CT	151.9	172.4	18.19	85.15	184.7	219.7	23.19	91.37	-32.8	-47.4	-5.00	-6.22
OCT	OWC Simple Cycle CT	149.0	168.3	17.76	68.00	190.9	225.9	23.85	91.92	-41.9	-57.6	-6.08	-23.91
OET	OWC Bridger Trans L	97.1	97.1	8.59	20.44	97.1	97.1	8.59	20.44	0.0	0.0	0.00	0.00
OEV	OWC Htr/OWC Trans L	104.1	104.1	9.56	23.49	104.1	104.1	9.56	23.49	0.0	0.0	0.00	0.00
UPS	Utah Pumped Storage	0.0	0.0	0.00	31.65	0.0	0.0	0.00	31.65	0.0	0.0	0.00	0.00
OPS	OWC Pump Storage	0.0	0.0	0.00	32.12	0.0	0.0	0.00	32.12	0.0	0.0	0.00	0.00
UPC	Utah Compressed Air	170.1	190.5	8.95	43.83	200.2	235.2	11.06	45.94	-30.1	-44.7	-2.10	-2.10

Updated RAMPP-4 Natural Gas Price Projection Assumptions

The natural gas price projection that was prepared by PacifiCorp for use in the RAMPP-4 document has been updated. The modifications are based on NYMEX market movements in the 1995 starting price and also as a result of comments made concerning the price growth rates by RAG participants during the presentation of the forecast on December 9, 1994. Figures #3 (1995 Starting Price) & #4 (Growth Rates) from that presentation have been updated and are enclosed as Figures #1 & #2 respectively.

In one last attempt to capture updated market pricing, both the futures market expectation for 1995 and the basis differential were reevaluated at the end of December 1994. The NYMEX futures prices for 1995 averaged $1.72/MMBtu, based on the markets closing on December 27, 1994. In addition, on that same day a telephone solicitation for a 1995 basis differential in Rocky Mountain markets yielded a market value of $.32/MMBtu. By subtracting the basis differential from the NYMEX price one can calculate $1.40/MMBtu as the 1995 starting price for the RAMPP-4 study. This would represent the market's expectation for the cost of spot gas into the pipeline. Figure #1 illustrates this analysis.

There was concern expressed by both PacifiCorp and several of the RAG participants during the presentation of the RAMPP-4 natural gas price projections, that the growth rates used by the major forecasters were higher than one would expect given the current market. As a reminder, the growth rates presented were 2.11%, 3.78% and 4.64% for the low, medium and high growth rates respectively. In order to provide a more practical "bracket" for the growth rates to be used in the modeling process, it was proposed that a 0.00 % real rate of growth might be used as the low growth rate. In addition, it was suggested at the meeting that the growth rate of 4.64% that was presented as the high case is unrealistically large.

The goal of the natural gas price forecast is to develop low, medium and high growth rate cases relating to the price of spot market gas that might be available to PacifiCorp in the future. Given the RAG group discussion described above, there are several resulting changes that PacifiCorp believes are prudent to make in the modeling assumptions. First, a 0.00% real dollar growth rate will be used to model the low growth expectations. Secondly, the growth rates of 2.11% and 3.78% from the previous study now become the medium and high growth rates respectively. Finally, the 4.64% growth rate case will not be incorporated into the upcoming modeling. In summary, Figure #2 illustrates these revised low, medium and high real dollar growth rates of 0.00%, 2.11% and 3.78% respectively, as they will be incorporated into the RAMPP-4 analysis.

Gas Prices

Rob Webster Fuel Cost Forecasts

	Year	RevisedLow Gas Price ¢/mmbtu	RevisedLow Escalation Rate	Revised Medium Gas Price ¢/mmbtu	Revised Medium Escalation Rate	Revised High Gas Price ¢/mmbtu	Revised High Escalation Rate
Fuel $1995		140.0		140.0		140.0	
5% Tax & Shrinkage		7.0		7.0		7.0	
	1995	147.0		147.0		147.0	
$1996	1996	151.9	3.30%	155.1	5.48%	157.6	7.20%
	1997	151.9	0.00%	158.3	2.11%	163.5	3.78%
	1998	151.9		161.7		169.7	
	1999	151.9		165.1		176.1	
	2000	151.9		168.6		182.8	
	2001	151.9		172.1		189.7	
	2002	151.9		175.8		196.9	
	2003	151.9		179.5		204.3	
	2004	151.9		183.2		212.1	
	2005	151.9		187.1		220.1	
	2006	151.9		191.1		228.4	
	2007	151.9		195.1		237.0	
	2008	151.9		199.2		246.0	
	2009	151.9		203.4		255.3	
	2010	151.9		207.7		264.9	
	2011	151.9		212.1		274.9	
	2012	151.9		216.6		285.3	
	2013	151.9		221.1		296.1	
	2014	151.9		225.8		307.3	
	2015	151.9		230.6		318.9	
	2016	151.9		230.6		318.9	
End Effects	2017	151.9		230.6		318.9	
Years	2018	151.9		230.6		318.9	
at 2015	2019	151.9		230.6		318.9	
Price	2020	151.9		230.6		318.9	
	2043	151.9		230.6		318.9	
	2044	151.9		230.6		318.9	
	2045	151.9		230.6		318.9	
Present Value ¢/mmbtu		2,762	¢/mmbtu	3,780	¢/mmbtu	4,865	¢/mmbtu
Real Levelized PV		151.9	¢/mmbtu	207.8	¢/mmbtu	267.4	¢/mmbtu
Incremental Heat Rate		7,167	btu/kWh	7,167	btu/kWh	7,167	btu/kWh
Real Levelized Mills		10.88	Mills/kWh	14.89	Mills/kWh	19.17	Mills/kWh
Transportation & Storage		3.33	Mills/kWh	3.33	Mills/kWh	3.33	Mills/kWh
Delivered Cost		**14.22**	Mills/kWh	**18.23**	Mills/kWh	**22.50**	Mills/kWh

Real $1996 Gas Prices

Year	Potential Coal: Utah Coal UG1	UG2	UG3	Wyo Coal WG1	WG2	Low Gas Price: Combined West	Peaker West	Combined East	Peaker East	Medium Gas Price: Combined West	Peaker West	Combined East	Peaker East	High Gas Price: Combined West	Peaker West	Combined East	Peaker East	Geo-thermal Steam
1996	85 5	99.4	115.4	38 7	39.9	198.4	163.3	172.6	157.1	201.6	166.5	175.8	160.3	204.1	169.0	178.3	162.8	107.3
1997	86 3	100.4	116.6	38.8	40.0	198.4	163.3	172.6	157.1	204.9	169.8	179.1	163.6	210.1	175.0	184.3	168.8	107.3
1998	87.2	101.4	117 8	39 0	40.2	198.4	163 3	172.6	157.1	208.2	173.1	182.4	166.9	216.2	181.1	190.4	174.9	107.3
1999	88.1	102.5	119.0	39.2	40.4	198.4	163.3	172.6	157.1	211.6	176.5	185.8	170.3	222.7	187.6	196.9	181.4	107.3
2000	89.0	103.5	120.2	39.3	40.5	198 4	163.3	172.6	157.1	215.1	180.0	189.3	173.8	229.3	194.2	203.5	188.0	107 3
2001	89.9	104 6	121.4	39.5	40.7	198 4	163.3	172.6	157.1	218.7	183.6	192.9	177.4	236.2	201.1	210.4	194.9	107.3
2002	90.9	105.6	122.7	39.6	40.8	198.4	163.3	172.6	157.1	222.3	187.2	196.5	181.0	243.4	208.3	217.6	202.1	107.3
2003	91.8	106.7	123.9	39.8	41.0	198.4	163 3	172.6	157.1	226.0	190.9	200.2	184.7	250.8	215.7	225.0	209.5	107.3
2004	92.7	107 8	125.2	39.9	41.2	198.4	163.3	172.6	157.1	229.8	194.7	204.0	188.5	258.6	223.5	232.8	217.3	107.3
2005	93.7	108.9	126.5	40.1	41.3	198.4	163.3	172.6	157.1	233.7	198.6	207.9	192.4	266.6	231.5	240.8	225.3	107.3
2006	94.7	110.0	127.8	40.3	41.5	198.4	163.3	172.6	157.1	237.6	202.5	211.8	196.3	274.9	239.8	249.1	233.6	107.3
2007	95.6	111.2	129.1	40.4	41.7	198.4	163.3	172.6	157.1	241.6	206.5	215.8	200.3	283.5	248.4	257.7	242.2	107.3
2008	96 6	112.3	130.4	40.6	41.8	198.4	163.3	172.6	157.1	245.8	210.7	220.0	204.5	292.5	257.4	266.7	251.2	107.3
2009	97 6	113.5	131.8	40.8	42.0	198.4	163.3	172.6	157.1	250.0	214.9	224.2	208.7	301.8	266.7	276.0	260.5	107.3
2010	98.6	114.6	133.1	40.9	42.2	198.4	163.3	172.6	157.1	254.3	219.2	228.5	213.0	311.4	276.3	285.6	270.1	107.3
2011	99.6	115 8	134.5	41.1	42.3	198.4	163.3	172.6	157.1	258.6	223.5	232.8	217.3	321.5	286.4	295.7	280.2	107.3
2012	100 6	117.0	135.9	41.2	42.5	198.4	163.3	172.6	157.1	263.1	228.0	237.3	221.8	331.8	296.7	306.0	290.5	107.3
2013	101.7	118.2	137.3	41.4	42.7	198.4	163.3	172.6	157.1	267.7	232.6	241.9	226.4	342.6	307.5	316.8	301.3	107.3
2014	102.7	119 4	138.7	41.6	42.9	198 4	163.3	172.6	157.1	272.4	237.3	246.6	231.1	353.8	318.7	328.0	312.5	107.3
2015	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2016	103 8	120.6	140.1	41.7	43.0	198 4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2017	103.8	120.6	140.1	41.7	43.0	198 4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2018	103 8	120.6	140.1	41.7	43 0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2019	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2020	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2021	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2022	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2023	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2024	103 8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2025	103 8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2026	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2027	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2028	103 8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2029	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2030	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2031	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2032	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2033	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2034	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2035	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2036	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2037	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2038	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2039	103.8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330.3	339.6	324.1	107.3
2040	103 8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330 3	339 6	324 1	107.3
2041	103 8	120.6	140.1	41.7	43.0	198.4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365 4	330 3	339 6	324.1	107.3
2042	103.8	120.6	140.1	41.7	43.0	198 4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330 3	339.6	324 1	107.3
2043	103.8	120.6	140.1	41.7	43.0	198 4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330 3	339 6	324 1	107.3
2044	103 8	120.6	140.1	41.7	43.0	198 4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330 3	339.6	324 1	107.3
2045	103 8	120.6	140.1	41.7	43.0	198 4	163.3	172.6	157.1	277.1	242.0	251.3	235.8	365.4	330 3	339.6	324 1	107.3
Net PV	1,792	2,083	2,419	744	767	3,611	2,972	3,141	2,859	4,629	3,990	4,159	3,877	5,713	5,074	5,244	4,961	1,953
Levelized	98.48	114.48	132.95	40.88	42.14	198.40	163.30	172.60	157.10	254.36	219.26	228.56	213.06	313.94	278.84	288.14	272.64	107.30

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Estimated 1994-1995 Rocky Mountain Pricing

Estimated 1994 Rocky Mountain Pricing

Month	Henry Hub $/MMBtu
Jan-94	2.340
Feb-94	2.710
Mar-94	2.210
Apr-94	2.040
May-94	1.920
Jun-94	1.900
Jul-94	1.960
Aug-94	1.660
Sep-94	1.490
Oct-94	1.510
Nov-94	1.580
Dec-94	1.720
1994 Projected Henry Hub Avg.	**1.920**
Less Basis Differential (Calc)	0.373
1994 Rocky Mtn Average	**1.548**

Cash Market Hub Trading - From Inside FERC

Estimated 1995 Rocky Mountain Pricing

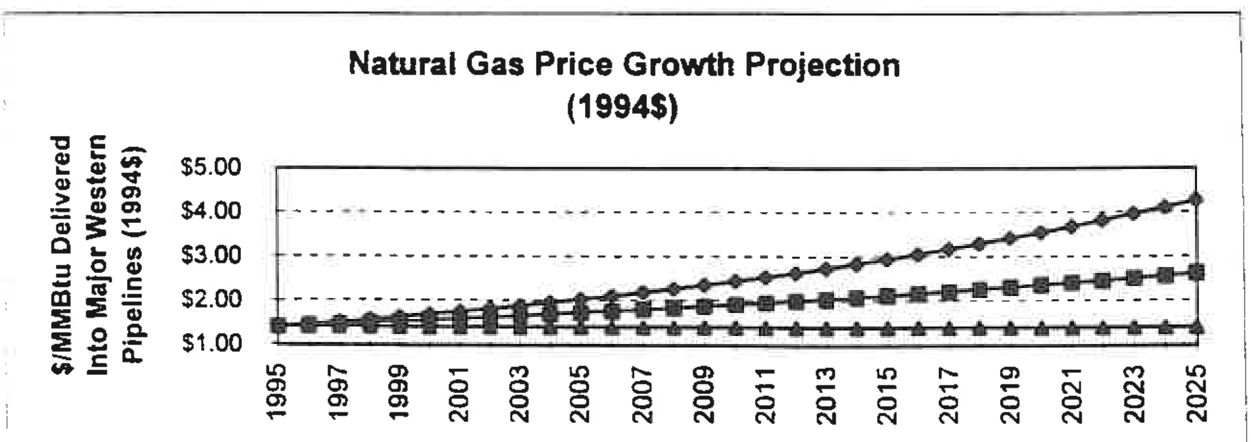
Month	*Henry Hub $/MMBtu
Jan-95	1.639
Feb-95	1.694
Mar-95	1.671
Apr-95	1.648
May-95	1.648
Jun-95	1.663
Jul-95	1.678
Aug-95	1.690
Sep-95	1.702
Oct-95	1.757
Nov-95	1.848
Dec-95	1.993
1995 Projected Henry Hub Avg.	**1.719**
**Less Basis Differential (Quote)	0.320
1995 Rocky Mtn Average	**1.399**

**Based on NYMEX futures market 12/27/94*

***Market quotation - URC Telephone 12/27/94*

RAMPP-4
Natural Gas Price Growth Projection
(1994$/MMBtu)

	High	Medium	Low
	3.78%	2.11%	0.00%
1995	1.40	1.40	1.40
1996	1.45	1.43	1.40
1997	1.51	1.46	1.40
1998	1.56	1.49	1.40
1999	1.62	1.52	1.40
2000	1.68	1.55	1.40
2001	1.75	1.59	1.40
2002	1.81	1.62	1.40
2003	1.88	1.65	1.40
2004	1.95	1.69	1.40
2005	2.03	1.72	1.40
2006	2.10	1.76	1.40
2007	2.18	1.80	1.40
2008	2.27	1.84	1.40
2009	2.35	1.87	1.40
2010	2.44	1.91	1.40
2011	2.53	1.95	1.40
2012	2.63	2.00	1.40
2013	2.73	2.04	1.40
2014	2.83	2.08	1.40
2015	2.94	2.12	1.40
2016	3.05	2.17	1.40
2017	3.17	2.22	1.40
2018	3.28	2.26	1.40
2019	3.41	2.31	1.40
2020	3.54	2.36	1.40
2021	3.67	2.41	1.40
2022	3.81	2.46	1.40
2023	3.95	2.51	1.40
2024	4.10	2.56	1.40
2025	4.26	2.62	1.40



Explanation of Potential Resources Report

(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(BB)	(CC)	(DD)	(EE)	(FF)
Capital Cost		Capital Cost $/kW			Fixed Cost				Convert to Mills		Energy Cost in 2000 (1996$)			Variable	Dispatch	Total
Unit	Trans-	Total	Payment	Annual Pmt	Fixed O&M $/kW-Yr			Ttl Fixed	Expected	Ttl Fixed	1st Year	Levelized		O&M	Cost	Resource
Cost	mission	Cap Cost	Factor	$/kW-Yr	O&M	Other	Total	$/kW-Yr	Utilization	Mills/kWh	¢/MMBTU		Mills/kWh	Mills/kWh	Mills/kWh	Cost
$467	$70	$537	9.04%	$48.54	$2.13	$0.00	$2.13	$50.67	85%	6.81	189.3	228.6	17.08	0.31	17.39	24.19
$831	$45	$876	9.04%	$79.19	$5.34	$0.00	$5.34	$84.53	85%	11.35	189.3	228.6	14.17	0.53	14.70	26.05

Col.	IPM Input	Calc'd on Spread-sheet	
(P)			Unit cost is the cost in $/kWh for a given size of plant (C) at a given location(G). Costs are overnight dollars and include the step up transformer.
(Q)			Transmission cost is the cost to connect the unit to the local grid.
(R)	x	x	Total Cap Cost (Capital Cost) is column (P) + (Q).
(S)	x		Payment Factor is the real levelized carrying charge for the unit. It takes into account income and property tax, and unit physical and book life.
(T)		x	Annual Pmt is column (R) x (S). IPM calculates this number internally.
(U)			Fixed O&M is the fixed annual cost of maintenance divided by the plant size.
(V)			O&M Other is costs that are fixed annually which for modeling purposes are included as a fixed cost. Some fuel costs (transportation and storage). are considered fixed and are included as a fixed cost
(W)	x	x	Total Fixed Cost is the total fixed cost per kW used by IPM. Columns (U) + (V).
(X)		x	Ttl Fixed is the total fixed annual cost per year. IPM calculates this number internally.
(Y)			Expected Utilization is used to convert fixed costs in $/kW to mills per kWh. IPM calculates this number internally for each year of the study.
(Z)		x	Ttl Fixed is the conversion of fixed costs in $/kW to mills per kWh. The formula is column (X) x 1000 / 8760 / (Y)
(AA)		x	1st Year Energy Cost in the year 2000 (1996$) is the cost of fuel in the year 2000. IPM uses the fuel price for each year, not just the price in 2000.
(BB)		x	Levelized Energy Cost in the year 2000 (1996$) is the real levelized cost of fuel for the unit from 2000 to 2045. IPM calculates a number similar to this internally.
(CC)		x	Levelized Energy Cost in the year 2000 (1996$) in mills / kWh is column (K) x (BB) / 100,000
(DD)	x		Variable O&M is the cost of operation and maintenance that is expected to vary with the operation of the unit.
(EE)		x	Dispatch cost is variable cost of operating the unit. It is useful to determine the dispatch order of plants. Columns (CC) + (DD)
(FF)		x	Total Resource Cost is the real levelized cost of the unit in mills per kWh. TRC is (Z) + (CC) + (DD)

Sorted by Total Resource Cost

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
		Unit Size MW			1st		Reserve	Forced	Maint.	Full Load Heat Rate		Emissions		
Short Name	Description	Unit Size	Max Annual	MWs Avail.	Year Avail	Approximate Location	Margin Contribution	Outage Rate	Outage Rate	Incremental	Average	NOx	TSP	CO2
										BTU/kWh		lbs/MMBTU		
UD1	Utah Gadsby Repower	320	320		2000	Gadsby	100%	3.3%	3.8%	7,472	7,846	0.016	0.003	118.0
UC2	Utah Cogen 2	21	210	420	2000	Wasatch Front UT	100%	3.3%	3.8%	6,200	6,800	0.016	0.003	118.0

Col.	IPM Input	Calc'd on Spread-sheet	
(A)	x		The short name is used by the IPM model to identify the Unit.
(B)	x		The full plant name.
(C)			Unit size is the plant size used when determining total costs. Larger units are generally cheaper in $/kW than smaller units.
(D)	x		Max Annual is the maximum amount of the resource that can be built in a given year.
(E)	x		MWs Avail. is the number of MW available to be built at the prices listed. In some cases, more MWs are available at a higher price. If so, they are listed on a separate line. A blank or zero means unlimited resources are available at this price.
(F)	x		1st Year Avail is the construction lead time to completion. It assumes an early 1996 decision to build the unit.
(G)			Approximate Location is information used internally to help develop unit cost. For example, transmission costs vary by location.
(H)	x		Reserve Margin is the percent of name plate capacity that is available to meet the winter peak.
(I)	x		Forced Outage Rate is the expected percentage of the time that the plant is unavailable due unexpected downtime.
(J)	x		Maint. Outage Rate is the percentage of the time the plant will be unavailable for planned maintenance.
(K)	x		Incremental Full Load Heat Rate is the conversion rate of fuel to kWh incremental generation for the last block of generation.
(L)			Average Full Load Heat Rate is the conversion rate of fuel to kWh. (Total BTU/Total kWh). This value is used in emission calculations.
(M) - (O)	x		Emission rates in lbs/MMBTU for NOx, TSP, and CO2.

	Project	Project Size (KW)	Miles New Line	Regional Service (Costs to serve loads) (within the region) ($)	($/KW)	Inter-Regional Service (Incremental costs to serve) (loads in other Regions) ($)	($/KW)
	Specific Sites						
	Cogen #1				0	$1,240,000,000	1,240
	Generic Estimates					for 1000 MW	
O	Cogen #2	200,000	10	$9,000,000	45		
W	Simple Cycle	200,000	10	$9,000,000	45		
C	Combined Cycle	200,000	10	$9,000,000	45		
	Geothermal	200,000	25	$15,000,000	75		
	Pumped Storage	200,000	25	$15,000,000	75		
	Wind Non-Firm	200,000	25	$15,000,000	75		
	Wind Firm	300,000	125	$66,000,000	220		
	Specific Sites						
	Hunter #4 Pulv Coal	440,000	0	$22,000,000	50	$1,240,000,000	1,240
	Hunter #5, 6, 7, 8...	440,000	35	$57,200,000	130	for 1000 MW	
	Hunter #4, IGCC	240,000	0	$12,000,000	50		
	Other Utah IGCC	240,000	35	$31,200,000	130		
U	Gadsby Repowering	370,000	0	$25,900,000	70		
T	Cogen #1				0		
A	**Generic Estimates**						
H	Cogen #2	200,000	10	$9,000,000	45		
	Simple Cycle	200,000	25	$15,000,000	75		
	Combined Cycle	200,000	25	$15,000,000	75		
	Geothermal	200,000	25	$15,000,000	75		
	Pumped Storage	200,000	25	$15,000,000	75		
	Compressed Air	200,000	25	$72,000,000	360		
	Wind Non-Firm	200,000	25	$15,000,000	75		
	Wind Firm	300,000	225	$108,000,000	360		
	Specific Sites						
W	Wyodak #2, Pulv Coal	260,000	300	$132,600,000	510	$74,100,000	285
Y	Wyodak #2, IGCC	260,000	300	$132,600,000	510	for 200 miles	
O	Other Wyoming Pulv Coal	260,000	300	$132,600,000	510	for 260mw	
M	Other Wyoming IGCC	260,000	300	$132,600,000	510	Wyo to Utah	
I	**Generic Estimates**						
N	Simple Cycle CT	200,000	25	$15,000,000	75		
G	Combined Cycle CT	200,000	25	$15,000,000	75		
	Wind Non-Firm	200,000	25	$15,000,000	75		
	Wind Firm	300,000	175	$109,500,000	365		

Adjusting Capital Costs Only

Percent of Cost	Geothermal OWC	Geothermal Utah	Wind Firm OWC	Wind Firm Utah	Wind Firm Wyo	Wind Non-Firm OWC	Wind Non-Firm Utah	Wind Non-Firm Wyo
100%	41.7	41.7	57.0	48.3	48.4	49.2	38.8	38.8
90%	39.0	39.0	53.3	45.4	45.5	46.3	36.9	36.9
80%	36.3	36.3	49.7	42.5	42.6	43.4	34.9	34.9
70%	33.6	33.6	46.0	39.6	39.8	40.5	33.0	33.0
60%	30.9	30.9	42.3	36.8	36.9	37.7	31.1	31.1
50%	28.1	28.1	38.7	33.9	34.0	34.8	29.2	29.2
40%	25.4	25.4	35.0	31.0	31.1	31.9	27.3	27.3
30%	22.7	22.7	31.4	28.2	28.2	29.0	25.3	25.3
20%	20.0	20.0	27.7	25.3	25.3	26.1	23.4	23.4
10%	17.3	17.3	24.0	22.4	22.4	23.3	21.5	21.5
0%	14.6	14.6	20.4	19.6	19.6	20.4	19.6	19.6

Adjusting Capital Cost and O&M

Percent of Cost	Geothermal OWC	Geothermal Utah	Wind Firm OWC	Wind Firm Utah	Wind Firm Wyo	Wind Non-Firm OWC	Wind Non-Firm Utah	Wind Non-Firm Wyo
100%	41.7	41.7	57.0	48.3	48.4	49.2	38.8	38.8
90%	38.6	38.6	51.3	43.4	43.6	44.3	34.9	34.9
80%	35.5	35.5	45.6	38.6	38.7	39.3	31.0	31.0
70%	32.4	32.4	39.9	33.8	33.9	34.4	27.1	27.1
60%	29.3	29.3	34.2	29.0	29.0	29.5	23.3	23.3
50%	26.2	26.2	28.5	24.1	24.2	24.6	19.4	19.4
40%	23.1	23.1	22.8	19.3	19.4	19.7	15.5	15.5
30%	20.0	20.0	17.1	14.5	14.5	14.8	11.6	11.6
20%	16.9	16.9	11.4	9.7	9.7	9.8	7.8	7.8
10%	13.8	13.8	5.7	4.8	4.8	4.9	3.9	3.9
0%	10.7	10.7	0.0	0.0	0.0	0.0	0.0	0.0

Reduction in cost needed to make Renewable Resources Competitive

Short Name	Description	Capital Cost $/kW: Total Cap Cost	Capital Cost $/kW: Payment Factor	Capital Cost $/kW: Annual Pmt $/kW-Yr	Fixed Cost: Fixed O&M $/kW-Yr: O&M	Fixed Cost: Fixed O&M $/kW-Yr: Other	Fixed Cost: Fixed O&M $/kW-Yr: Total	Fixed Cost: Ttl Fixed $/kW-Yr	Convert to Mills: Expected Utilization	Convert to Mills: Ttl Fixed Mills/kWh	Energy Cost in 2000 (1996$): 1st Year ¢/MMBTU	Energy Cost in 2000 (1996$): Levelized ¢/MMBTU	Energy Cost in 2000 (1996$): Levelized Mills/kWh	Variable O&M Mills/kWh	Total Resource Cost
Least Cost Resources															
UD1	Utah Gadsby Repower	$537	9.04%	$48.54	$2.13	$0.00	$2.13	$50.67	85%	6.81	189.3	228.6	17.08	0.31	24.19
UC2	Utah Cogen 2	$876	9.04%	$79.19	$5.34	$0.00	$5.34	$84.53	85%	11.35	189.3	228.6	14.17	0.53	26.05
OC2	OWC Cogen 2	$752	9.04%	$67.98	$5.34	$0.00	$5.34	$73.32	85%	9.85	215.1	254.4	15.77	0.53	26.15
OC1	OWC Cogen 1	$1,174	9.04%	$106.13	$5.34	$0.00	$5.34	$111.47	85%	14.97	215.1	254.4	10.94	0.53	26.44
UC1	Utah Cogen 1	$1,380	9.04%	$124.75	$5.34	$0.00	$5.34	$130.09	85%	17.47	189.3	228.6	9.83	0.53	27.83
Renewable Resources before Adjustment															
UW1	Utah Wind Non-firm	$1,075	5.56%	$59.77	$9.50	$51.34	$60.84	$120.61	36%	38.78	0.0	0.0	0.00	0.00	38.78
WW1	Wyo Wind Non-firm	$1,075	5.56%	$59.77	$9.50	$51.34	$60.84	$120.61	36%	38.78	0.0	0.0	0.00	0.00	38.78
OGT	OWC Geothermal	$2,220	9.60%	$213.12	$15.00	$0.00	$15.00	$228.12	90%	28.93	107.3	107.3	10.73	2.00	41.66
UGT	Utah Geothermal	$2,220	9.60%	$213.12	$15.00	$0.00	$15.00	$228.12	90%	28.93	107.3	107.3	10.73	2.00	41.66
UW2	Utah Wind Firm	$1,360	6.56%	$89.22	$9.50	$51.34	$60.84	$150.06	36%	48.25	0.0	0.0	0.00	0.00	48.25
WW2	Wyo Wind Firm	$1,365	6.57%	$89.68	$9.50	$51.34	$60.84	$150.52	36%	48.40	0.0	0.0	0.00	0.00	48.40
OW1	OWC Wind Non-Firm	$1,075	6.57%	$70.63	$9.50	$40.50	$50.00	$120.62	28%	49.18	0.0	0.0	0.00	0.00	49.18
OW2	OWC Wind Firm	$1,220	7.36%	$89.79	$9.50	$40.50	$50.00	$139.79	28%	56.99	0.0	0.0	0.00	0.00	56.99
Capital Cost Reduced by 65%															
UW1	Utah Wind Non-firm	$376	5.56%	$20.92	$9.50	$51.34	$60.84	$81.76	36%	26.29	0.0	0.0	0.00	0.00	26.29
WW1	Wyo Wind Non-firm	$376	5.56%	$20.92	$9.50	$51.34	$60.84	$81.76	36%	26.29	0.0	0.0	0.00	0.00	26.29
OGT	OWC Geothermal	$777	9.60%	$74.59	$15.00	$0.00	$15.00	$89.59	90%	11.36	107.3	107.3	10.73	2.00	24.09
UGT	Utah Geothermal	$777	9.60%	$74.59	$15.00	$0.00	$15.00	$89.59	90%	11.36	107.3	107.3	10.73	2.00	24.09
UW2	Utah Wind Firm	$476	6.56%	$31.23	$9.50	$51.34	$60.84	$92.07	36%	29.61	0.0	0.0	0.00	0.00	29.61
WW2	Wyo Wind Firm	$478	6.57%	$31.39	$9.50	$51.34	$60.84	$92.23	36%	29.66	0.0	0.0	0.00	0.00	29.66
OW1	OWC Wind Non-Firm	$376	6.57%	$24.72	$9.50	$40.50	$50.00	$74.72	28%	30.46	0.0	0.0	0.00	0.00	30.46
OW2	OWC Wind Firm	$427	7.36%	$31.43	$9.50	$40.50	$50.00	$81.42	28%	33.20	0.0	0.0	0.00	0.00	33.20
Capital Cost Reduced by 55%															
OGT	OWC Geothermal	$999	9.60%	$95.90	$15.00	$0.00	$15.00	$110.90	90%	14.07	107.3	107.3	10.73	2.00	26.80
UGT	Utah Geothermal	$999	9.60%	$95.90	$15.00	$0.00	$15.00	$110.90	90%	14.07	107.3	107.3	10.73	2.00	26.80
Capital Cost and Variable Costs Reduced by 40%															
OGT	OWC Geothermal	$1,332	9.60%	$127.87	$15.00	$0.00	$15.00	$142.87	90%	18.12	64.4	64.4	6.44	2.00	26.56
UGT	Utah Geothermal	$1,332	9.60%	$127.87	$15.00	$0.00	$15.00	$142.87	90%	18.12	64.4	64.4	6.44	2.00	26.56

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Forecasted Cost of Capital
RAMPP-4

	Capital Structure	Cost	Weighted Cost
Long Term Debt	48%	8.60%	4.13%
Preferred Stock	6%	8.11%	0.49%
Common Equity	46%	12.00%	5.52%
TOTAL	100%		10.13%

Forecasted Cost of Capital
RAMPP-3

	Capital Structure	Cost	Weighted Cost
Long Term Debt	49%	8.99%	4.41%
Preferred Stock	6%	8.93%	0.54%
Common Equity	45%	12.20%	5.49%
TOTAL	100%		10.43%

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Chapter 3:

Tables Summarizing Results

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 5-1, Page 1 of 8

	Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant		No DSM Allowed	DSM Costs		
										Reduced by		Increased
							Med Gas	High Gas		20%	15%	15%
	Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load	8,807				8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485				1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM	(352)				(358)	(359)	(400)	0	(450)	(436)	(297)
4	**Total Requirements**	9,940				9,934	9,933	9,892	10,292	9,842	9,856	9,995
5	Existing Generation	10,123				9,974	9,689	9,689	10,123	10,122	10,122	10,123
6	Firm Purchases	424				424	424	424	424	424	424	424
7	New Resources											
8	Renewable	0				0	0	0	0	0	0	0
9	Cogeneration	363				431	715	966	683	371	382	351
10	Combined Cycle CT	222				297	297	0	297	105	110	297
11	Coal	0				0	0	0	0	0	0	0
12	Transmission	0				0	0	0	0	0	0	0
13	Peaking Resources	0				0	0	0	0	0	0	0
14	**Total Resources**	11,132				11,126	11,125	11,079	11,527	11,022	11,038	11,195
15	Reserves	1,192				1,192	1,192	1,187	1,235	1,180	1,182	1,200
16	Reserve Margin (RM) (%)	12.0				12.0	12.0	12.0	12.0	12.0	12.0	12.0
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load	9,104	9,273	9,273	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	1,195	1,195	995	995	995	995	995	995	995	995
19	less DSM	(446)	(608)	(616)	(445)	(453)	(455)	(487)	0	(529)	(515)	(387)
20	**Total Requirements**	9,653	9,860	9,852	9,654	9,646	9,645	9,612	10,099	9,570	9,584	9,712
21	Existing Generation	10,162	10,054	10,054	10,161	10,012	9,669	9,669	10,161	10,161	10,161	10,161
22	Firm Purchases	319	317	317	319	319	319	319	319	319	319	319
23	New Resources											
24	Renewable	0	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	387	0	0	104	458	760	1,028	726	395	406	373
26	Combined Cycle CT	248	0	0	229	331	331	0	331	117	123	331
27	Coal	0	721	698	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	247	262	0	0	0	0	0	0	0	0
30	**Total Resources**	11,115	11,340	11,331	10,813	11,120	11,079	11,016	11,538	10,992	11,009	11,184
31	Reserves	1,462	1,480	1,479	1,159	1,474	1,435	1,404	1,439	1,422	1,426	1,472
32	Reserve Margin (RM) (%)	15.1	15.0	15.0	12.0	15.3	14.9	14.6	14.2	14.9	14.9	15.2

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Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 5-1, Page 2 of 8

	Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant		No DSM Allowed	DSM Costs		
										Reduced by		Increased
							Med Gas	High Gas		20%	15%	15%
	Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Annual Energy in Year 2005 (MWa)											
1	Native Load	6,463	6,634	6,634	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	376	383	305	305	305	299	305	305	305	305
3	Firm Sales	1,266	1,410	1,410	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	512	507	691	957	914	931	1,020	884	889	937
5	less DSM	(244)	(348)	(351)	(200)	(250)	(251)	(272)	0	(299)	(291)	(196)
6	**Total Requirements**	8,710	8,584	8,583	8,524	8,741	8,696	8,686	9,053	8,618	8,631	8,775
7	Existing Generation	7,768	7,473	7,476	7,809	7,672	7,351	7,313	7,760	7,746	7,746	7,787
8	Firm Purchases	400	364	364	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	47	44	46	0	5	22	0	18	15	4
10	New Resources											
11	Renewable	0	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	0	0	97	426	707	951	676	367	378	347
13	Combined Cycle CT	183	0	0	172	242	233	0	217	88	92	237
14	Coal	0	661	639	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	55	59	0	0	0	0	0	0	0	0
17	**Total Resources**	8,710	8,599	8,582	8,524	8,741	8,696	8,686	9,053	8,618	8,631	8,775
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO_2	55,189			55,577	54,430	55,104	55,413	#N/A	55,094	55,118	55,315
19	NO_x	125			125	123	125	126	#N/A	125	125	125
	Financial Results with End Effects to 2045											
20	50-year Utility Cost											
21	NPV at 8.6% (million $)	42,560			42,284	42,610	43,273	43,620	43,471	42,564	42,571	42,578
22	Real Levelized (mills/kWh)	42.55			41.98	42.64	43.31	43.86	41.52	43.00	42.96	42.17
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	42,990			42,610	43,052	43,716	44,158	43,471	43,259	43,225	42,905
25	Real Levelized (mills/kWh)	41.07			40.70	41.12	41.76	42.18	41.52	41.32	41.29	40.98
25	**IPM Obj Function (millions $)**	19,164			18,930	19,390	19,485	19,579	19,620	18,923	18,998	19,307

(A) Case 2 and 3 are RAMPP-3 models. Since these models did not have a 2005 run year, 2003 is presented. Therefore these two cases should only be compared against each other.

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Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 5-1, Page 3 of 8

	Case Name	Base Case Study	Load Growth Rate: Medium Low	Load Growth Rate: Medium High	Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices: High	High Gas Price Non-firm Prices: Med	Lumped Resource Additions	Non-Firm Prices: Lower by 25%	Non-Firm Prices: Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Summer Peak Capacity in Year 2005 (MW)										
1	Native Load	8,807	7,597	10,117	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM	(352)	(112)	(505)	(303)	(392)	(400)	(435)	(367)	(347)	(355)
4	**Total Requirements**	9,940	8,970	11,097	9,989	9,900	9,892	9,857	9,925	9,945	9,937
5	Existing Generation	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123
6	Firm Purchases	424	424	424	424	424	424	424	424	424	424
7	New Resources										
8	Renewable	0	0	0	0	0	0	0	0	0	0
9	Cogeneration	363	0	1,584	344	541	532	493	301	294	340
10	Combined Cycle CT	222	0	297	297	0	0	0	297	297	243
11	Coal	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	0	0	0	0	0	0
14	**Total Resources**	11,132	10,547	12,429	11,188	11,088	11,079	11,040	11,145	11,138	11,130
15	Reserves	1,192	1,577	1,332	1,199	1,188	1,187	1,183	1,220	1,194	1,193
16	Reserve Margin (RM) (%)	12.0	17.6	12.0	12.0	12.0	12.0	12.0	12.3	12.0	12.0
	Winter Peak Capacity in Year 2005 (MW)										
17	Native Load	9,104	7,895	10,473	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	995	995	995	995	995	995	995	995	995
19	less DSM	(446)	(131)	(619)	(394)	(482)	(487)	(514)	(460)	(438)	(450)
20	**Total Requirements**	9,653	8,759	10,849	9,705	9,617	9,612	9,585	9,640	9,661	9,649
21	Existing Generation	10,162	10,161	10,161	10,161	10,161	10,161	10,161	10,161	10,161	10,161
22	Firm Purchases	319	319	319	319	319	319	319	319	319	319
23	New Resources										
24	Renewable	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	387	0	1,685	366	576	566	524	320	313	362
26	Combined Cycle CT	248	0	331	331	0	0	0	331	331	271
27	Coal	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	0	0	0	0	0	0
30	**Total Resources**	11,115	10,480	12,497	11,177	11,056	11,046	11,004	11,131	11,124	11,113
31	Reserves	1,462	1,721	1,647	1,472	1,438	1,434	1,419	1,492	1,463	1,464
32	Reserve Margin (RM) (%)	15.1	19.7	15.2	15.2	15.0	14.9	14.8	15.5	15.1	15.2

Comparative Results of RAMPP-4 Runns
Resource Selections by 10th year, Emissions and Financial Results

Table 5-1, Page 4 of 8

	Case Name	Base Case Study	Load Growth Rate: Medium Low	Load Growth Rate: Medium High	Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices: High	High Gas Price Non-firm Prices: Med	Lumped Resource Additions	Non-Firm Prices: Lower by 25%	Non-Firm Prices: Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Annual Energy in Year 2005 (MWa)										
1	Native Load	6,463	5,596	7,438	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	978	1,092	860	926	927	886	939	645	991
5	less DSM	(244)	(85)	(346)	(196)	(268)	(272)	(290)	(256)	(238)	(247)
6	**Total Requirements**	8,710	8,060	9,755	8,698	8,690	8,688	8,629	8,717	8,440	8,777
7	Existing Generation	7,768	7,652	7,680	7,672	7,748	7,751	7,715	7,783	7,514	7,830
8	Firm Purchases	400	400	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	8	0	20	10	12	27	5	125	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	0	1,513	340	533	525	488	298	289	337
13	Combined Cycle CT	183	0	163	266	0	0	0	232	113	210
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	0	0	0
17	**Total Resources**	8,710	8,060	9,755	8,698	8,690	8,688	8,629	8,717	8,440	8,777
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	55,189	52,938	57,983	54,729	55,408	55,496	55,508	55,109	54,185	55,205
19	NO_x	125	124	125	123	126	127	127	125	121	125
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	42,560	38,921	47,134	42,649	41,924	42,457	43,052	42,312	43,459	41,564
22	Real Levelized (mills/kWh)	42.55	43.92	41.31	42.21	42.11	42.69	43.44	42.38	43.39	41.57
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	42,990	39,062	47,849	42,973	42,445	42,995	43,705	42,773	43,885	41,998
25	Real Levelized (mills/kWh)	41.07	43.03	39.64	41.05	40.54	41.07	41.75	40.86	41.92	40.12
25	**IPM Obj Function (millions $)**	19,164	14,895	24,484	19,113	18,860	19,098	19,791	19,175	19,990	18,337

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 5-1, Page 5 of 8

		Base	Overbuild by 250 MW in 1999			Overbuild by 500 MW in 1999			Underbuilding until 2005		
		Case	with Non-Firm Prices that are			with Non-Firm Prices that are			CCCT+2	CCCT+6	CCCT+10
	Case Name	Study	25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher
	Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Summer Peak Capacity in Year 2005 (MW)										
1	Native Load	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM	(352)	(345)	(351)	(351)	(340)	(348)	(348)	(353)	(363)	(363)
4	**Total Requirements**	**9,940**	**9,947**	**9,941**	**9,941**	**9,952**	**9,944**	**9,945**	**9,939**	**9,929**	**9,929**
5	Existing Generation	10,123	10,123	10,123	10,122	10,123	10,122	10,122	10,123	10,123	10,123
6	Firm Purchases	424	424	424	424	424	424	424	424	424	424
7	New Resources										
8	Renewable	0	0	0	0	0	0	0	0	0	0
9	Cogeneration	363	297	364	371	470	470	470	86	150	344
10	Combined Cycle CT	222	297	223	226	130	121	169	168	102	168
11	Coal	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	0	0	0	331	321	321
14	**Total Resources**	**11,132**	**11,141**	**11,134**	**11,143**	**11,146**	**11,137**	**11,185**	**11,131**	**11,121**	**11,380**
15	Reserves	1,192	1,194	1,193	1,202	1,194	1,193	1,241	1,193	1,192	1,451
16	Reserve Margin (RM) (%)	12.0	12.0	12.0	12.1	12.0	12.0	12.5	12.0	12.0	14.6
	Winter Peak Capacity in Year 2005 (MW)										
17	Native Load	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	995	995	995	995	995	995	995	995	995
19	less DSM	(446)	(435)	(444)	(447)	(430)	(441)	(442)	(444)	(458)	(460)
20	**Total Requirements**	**9,653**	**9,664**	**9,655**	**9,652**	**9,670**	**9,658**	**9,657**	**9,655**	**9,641**	**9,640**
21	Existing Generation	10,162	10,161	10,162	10,161	10,162	10,161	10,161	10,161	10,161	10,161
22	Firm Purchases	319	319	319	319	319	319	319	319	319	319
23	New Resources										
24	Renewable	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	387	316	387	395	500	500	500	91	160	366
26	Combined Cycle CT	248	331	249	251	145	134	188	187	114	187
27	Coal	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	0	0	0	352	342	342
30	**Total Resources**	**11,115**	**11,127**	**11,116**	**11,127**	**11,125**	**11,115**	**11,169**	**11,110**	**11,096**	**11,375**
31	Reserves	1,462	1,463	1,461	1,474	1,456	1,457	1,512	1,455	1,455	1,735
32	Reserve Margin (RM) (%)	15.1	15.1	15.1	15.3	15.1	15.1	15.7	15.1	15.1	18.0

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 5-1, Page 6 of 8

	Case Name	Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
									CCCT+2	CCCT+6	CCCT+10
			25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher
	Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Annual Energy in Year 2005 (MWa)										
1	Native Load	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	638	923	994	674	919	1,011	502	695	1,009
5	less DSM	(244)	(236)	(243)	(244)	(232)	(240)	(240)	(244)	(255)	(255)
6	**Total Requirements**	8,710	8,435	8,713	8,784	8,475	8,712	8,804	8,291	8,473	8,787
7	Existing Generation	7,768	7,514	7,768	7,822	7,519	7,742	7,791	7,520	7,778	7,822
8	Firm Purchases	400	400	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	148	2	0	107	6	0	204	49	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	261	360	368	400	465	465	85	149	341
13	Combined Cycle CT	183	113	184	194	49	100	148	68	86	149
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	13	13	75
17	**Total Resources**	8,710	8,435	8,713	8,784	8,475	8,712	8,804	8,291	8,473	8,787
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	55,189	54,153	55,186	55,226	54,090	55,134	55,157	54,344	55,334	55,310
19	NO_x	125	121	125	125	121	125	125	122	126	126
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	42,560	43,512	42,598	41,676	43,641	42,767	41,779	43,707	42,966	41,719
22	Real Levelized (mills/kWh)	42.55	43.43	42.58	41.64	43.53	42.73	41.74	43.68	43.03	41.79
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	42,990	43,932	43,025	42,098	44,051	43,187	42,196	44,146	43,415	42,167
25	Real Levelized (mills/kWh)	41.07	41.97	41.10	40.21	42.08	41.25	40.31	42.17	41.47	40.28
25	**IPM Obj Function (millions $)**	19,164	20,043	19,189	18,344	20,107	19,227	18,368	20,027	19,321	18,542

Note: (A) An additional 2, 6, or 10 mill/kWh was added to the CCCT cost to represent an additonal profit margin for an energy producer selling power in a sellers market.

10/27/95 8:57 AM

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 5-1, Page 7 of 8

	Case Name	Base Case Study	Added Transm: Test Transm Conversion	Added Transm: Bridger to OWC	Added Transm: Utah to OWC	Cheaper Renew-ables	Extend Inputs to 2045: Firm Contracts	Extend Inputs to 2045: Loads and DSM	Extend Inputs to 2045: All Inputs	Environmental Adders with CO2 Costs at: $10/ton	Environmental Adders with CO2 Costs at: $25/ton	Environmental Adders with CO2 Costs at: $40/ton
	Case #	1	57	58	59	61	65	66	67	71	72	73
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485	1,485	1,485	1,485	1,485	2,130	1,485	2,130	1,485	1,485	1,485
3	less DSM	(352)	(402)	(353)	(352)	(348)	(370)	(332)	(373)	(362)	(426)	(460)
4	**Total Requirements**	9,940	9,890	9,940	9,940	9,944	10,567	9,960	10,564	9,930	9,866	9,832
5	Existing Generation	10,123	10,123	10,122	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123
6	Firm Purchases	424	424	424	424	424	692	424	692	424	424	424
7	New Resources											
8	Renewable	0	0	0	0	54	0	0	0	0	592	876
9	Cogeneration	363	233	364	363	217	723	355	720	985	1,973	1,660
10	Combined Cycle CT	222	297	222	222	120	297	254	297	297	1,889	2,532
11	Coal	0	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	200	0	0	0	0	0	0
14	**Total Resources**	11,132	11,077	11,132	11,132	11,137	11,835	11,155	11,832	11,829	15,002	15,616
15	Reserves	1,192	1,187	1,192	1,192	1,157	1,268	1,195	1,268	1,899	4,740	5,199
16	Reserve Margin (RM) (%)	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	19.1	52.0	58.8
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	995	995	995	995	1,463	995	1,463	995	995	995
19	less DSM	(446)	(487)	(445)	(446)	(439)	(459)	(427)	(462)	(462)	(509)	(537)
20	**Total Requirements**	9,653	9,612	9,654	9,653	9,660	10,108	9,672	10,105	9,637	9,590	9,562
21	Existing Generation	10,162	10,161	10,161	10,162	10,162	10,161	10,162	10,161	10,161	10,161	10,161
22	Firm Purchases	319	319	319	319	319	954	319	954	319	319	319
23	New Resources											
24	Renewable	0	0	0	0	54	0	0	0	0	712	1,166
25	Cogeneration	387	248	387	387	230	769	377	766	1,048	2,099	1,766
26	Combined Cycle CT	248	331	247	248	133	331	283	331	331	2,025	2,709
27	Coal	0	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	200	0	0	0	0	0	0
30	**Total Resources**	11,115	11,059	11,114	11,115	11,098	12,216	11,141	12,212	11,859	15,316	16,121
31	Reserves	1,462	1,447	1,461	1,462	1,438	2,107	1,469	2,107	2,222	5,726	6,559
32	Reserve Margin (RM) (%)	15.1	15.1	15.1	15.1	14.9	20.8	15.2	20.8	23.1	59.7	68.6

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 5-1, Page 8 of 8

	Case Name	Base Case Study	Added Transm: Test Transm Conversion	Added Transm: Bridger to OWC	Added Transm: Utah to OWC	Cheaper Renew-ables	Extend Inputs to 2045: Firm Contracts	Extend Inputs to 2045: Loads and DSM	Extend Inputs to 2045: All Inputs	Environmental Adders with CO2 Costs at: $10/ton	Environmental Adders with CO2 Costs at: $25/ton	Environmental Adders with CO2 Costs at: $40/ton
	Case #	1	57	58	59	61	65	66	67	71	72	73
	Annual Energy in Year 2005 (MWa)											
1	Native Load	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	300	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,683	1,266	1,683	1,266	1,266	1,266
4	Non-Firm Sales	921	890	954	926	912	971	931	970	239	180	283
5	less DSM	(244)	(272)	(244)	(244)	(240)	(256)	(227)	(255)	(256)	(287)	(304)
6	**Total Requirements**	8,710	8,650	8,743	8,715	8,706	9,165	8,736	9,166	8,017	7,921	8,013
7	Existing Generation	7,768	7,785	7,787	7,768	7,739	7,724	7,776	7,726	5,892	2,453	1,998
8	Firm Purchases	400	400	400	400	400	523	400	523	400	403	403
9	Non-Firm Purchases	0	3	0	4	5	0	4	0	449	627	498
10	New Resources		0	0	0	51	0	0	0	0	608	956
11	Renewable	0	0	0	0	214	716	351	713	975	1,953	1,644
12	Cogeneration	360	231	360	360	99	202	205	203	302	1,878	2,514
13	Combined Cycle CT	183	232	196	183	0	0	0	0	0	0	0
14	Coal	0	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	198	0	0	0	0	0	0
17	**Total Resources**	8,710	8,650	8,743	8,715	8,706	9,165	8,736	9,166	8,017	7,921	8,013
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO_2	55,189	55,160	55,320	55,211	54,216	54,851	55,220	54,838	44,911	24,956	20,639
19	NO_x	125	125	126	125	125	125	125	125	91	32	22
	Financial Results with End Effects to 2045											
20	50-year Utility Cost											
21	NPV at 8.6% (million $)	42,560	41,877	43,039	43,060	42,277	42,273	45,026	45,141	43,665	52,388	55,552
22	Real Levelized (mills/kWh)	42.55	42.12	43.03	43.05	42.19	42.35	41.29	41.53	43.74	52.84	56.16
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	42,990	42,426	43,469	43,490	42,698	42,744	45,473	45,656	44,110	53,027	56,276
25	Real Levelized (mills/kWh)	41.07	40.53	41.52	41.54	40.79	40.83	39.97	40.13	42.13	50.65	53.76
25	**IPM Obj Function (millions $)**	19,164	19,541	19,154	19,163	18,657	22,121	22,579	26,347	34,736	46,812	56,486

10/27/95 8:58 AM

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Comparative Results of RAMPP-4 Runs (Case Results less Case 1)

Resource Selections by 10th year, Emissions and Financial Results

		Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant		No DSM Allowed	DSM Costs		
								Med Gas	High Gas		Reduced by 20%	Reduced by 15%	Increased 15%
		Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Summer Peak Capacity in Year 2005 (MW)												
1	Native Load		0				0	0	0	0	0	0	0
2	Firm Sales		0				0	0	0	0	0	0	0
3	less DSM		0				(6)	(7)	(48)	352	(98)	(84)	56
4	**Total Requirements**		0				(6)	(7)	(48)	352	(98)	(84)	56
5	Existing Generation		0				(149)	(434)	(434)	0	(0)	(0)	0
6	Firm Purchases		0				0	0	0	0	0	0	0
7	New Resources												
8	Renewable		0				0	0	0	0	0	0	0
9	Cogeneration		0				67	351	603	319	8	18	(13)
10	Combined Cycle CT		0				75	75	(222)	75	(117)	(112)	75
11	Coal		0				0	0	0	0	0	0	0
12	Transmission		0				0	0	0	0	0	0	0
13	Peaking Resources		0				0	0	0	0	0	0	0
14	**Total Resources**		0				(6)	(7)	(53)	395	(110)	(94)	63
15	Reserves		0				(0)	(0)	(5)	43	(12)	(10)	7
16	Reserve Margin (RM) (%)		0.0				0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Winter Peak Capacity in Year 2005 (MW)												
17	Native Load		0			0	0	0	0	0	0	0	0
18	Firm Sales		0			0	0	0	0	0	0	0	0
19	less DSM		0			1	(7)	(9)	(41)	446	(83)	(69)	59
20	**Total Requirements**		0			1	(7)	(9)	(41)	446	(83)	(69)	59
21	Existing Generation		0			(0)	(150)	(493)	(493)	(1)	(0)	(0)	(1)
22	Firm Purchases		0			0	0	0	0	0	0	0	0
23	New Resources												
24	Renewable		0			0	0	0	0	0	0	0	0
25	Cogeneration		0			(282)	72	374	641	340	8	19	(13)
26	Combined Cycle CT		0			(19)	84	84	(248)	84	(130)	(125)	84
27	Coal		0			0	0	0	0	0	0	0	0
28	Transmission		0			0	0	0	0	0	0	0	0
29	Peaking Resources		0			0	0	0	0	0	0	0	0
30	**Total Resources**		0			(302)	6	(35)	(99)	423	(122)	(106)	70
31	Reserves		0			(303)	13	(27)	(58)	(23)	(39)	(36)	11
32	Reserve Margin (RM) (%)		0.0			(3.1)	0.1	(0.3)	(0.5)	(0.9)	(0.3)	(0.3)	0.0

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)

Resource Selections by 10th year, Emissions and Financial Results

Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant		No DSM Allowed	DSM Costs		
									Reduced by		Increased
						Med Gas	High Gas		20%	15%	15%
Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
Annual Energy in Year 2005 (MWa)											
1 Native Load	0			0	0	0	0	0	0	0	0
2 Pump Storage/Peak Return	0			0	0	0	(6)	0	0	0	0
3 Firm Sales	0			0	0	0	0	0	0	0	0
4 Non-Firm Sales	0			(230)	36	(7)	10	99	(37)	(33)	16
5 less DSM	0			44	(6)	(7)	(28)	244	(55)	(47)	48
6 **Total Requirements**	0			(186)	30	(14)	(25)	343	(92)	(79)	65
7 Existing Generation	0			41	(96)	(417)	(455)	(8)	(22)	(22)	19
8 Firm Purchases	0			0	0	0	0	0	0	0	0
9 Non-Firm Purchases	0			46	0	5	22	0	18	15	4
10 New Resources											
11 Renewable	0			0	0	0	0	0	0	0	0
12 Cogeneration	0			(263)	67	348	591	316	8	18	(12)
13 Combined Cycle CT	0			(11)	60	50	(183)	34	(95)	(90)	54
14 Coal	0			0	0	0	0	0	0	0	0
15 Transmission	0			0	0	0	0	0	0	0	0
16 Peaking Resources	0			0	0	0	0	0	0	0	0
17 **Total Resources**	0			(186)	30	(14)	(25)	343	(92)	(79)	65
Average Annual Emission in 1996-2045 (1000 tons)											
18 CO_2	0			388	-758	-85	224	732	-94	-71	127
19 NO_x	0			0	-2	0	1	0	0	0	0
Financial Results with End Effects to 2045											
20 50-year Utility Cost											
21 NPV at 8.6% (million $)	0			-276	50	712	1,060	910	4	11	18
22 **Real Levelized (mills/kWh)**	0.00			-0.57	0.09	0.76	1.31	-1.03	0.45	0.41	-0.38
23 50-year Total Resources Cost											
24 NPV at 8.6% (million $)	0			-381	62	726	1,168	481	269	235	-85
25 Real Levelized (mills/kWh)	0.00			-0.37	0.05	0.69	1.11	0.45	0.25	0.22	-0.09
25 **IPM Obj Function (millions $)**	0			-234	226	322	415	456	-240	-166	143

(A) Case 2 and 3 are RAMPP-3 models. Since these models did not have a 2005 run year, 2003 is presented.
Therefore these two cases should only be compared against each other.

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)

Resource Selections by 10th year, Emissions and Financial Results

	Case Name	Base Case Study	Load Growth Rate Medium Low	Load Growth Rate Medium High	Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices High	High Gas Price Non-firm Prices Med	Lumped Resource Additions	Non-Firm Prices Lower by 25%	Non-Firm Prices Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Summer Peak Capacity in Year 2005 (MW)										
1	Native Load	0	(1,210)	1,310	0	0	0	0	0	0	0
2	Firm Sales	0	0	0	0	0	0	0	0	0	0
3	less DSM	0	241	(153)	50	(40)	(48)	(83)	(14)	5	(2)
4	**Total Requirements**	0	(969)	1,157	50	(40)	(48)	(83)	(14)	5	(2)
5	Existing Generation	0	1	1	1	1	1	1	1	1	0
6	Firm Purchases	0	0	0	0	0	0	0	0	0	0
7	New Resources										
8	Renewable	0	0	0	0	0	0	0	0	0	0
9	Cogeneration	0	(363)	1,221	(20)	178	169	129	(63)	(69)	(23)
10	Combined Cycle CT	0	(222)	75	75	(222)	(222)	(222)	75	75	21
11	Coal	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	0	0	0	0	0	0
14	**Total Resources**	0	(585)	1,297	56	(44)	(53)	(92)	13	6	(2)
15	Reserves	0	384	139	6	(4)	(5)	(10)	28	1	0
16	Reserve Margin (RM) (%)	0.0	5.6	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0
	Winter Peak Capacity in Year 2005 (MW)										
17	Native Load	0	(1,209)	1,369	0	0	0	0	0	0	0
18	Firm Sales	0	0	0	0	0	0	0	0	0	0
19	less DSM	0	315	(173)	52	(36)	(41)	(68)	(14)	8	(4)
20	**Total Requirements**	0	(894)	1,196	52	(36)	(41)	(68)	(14)	8	(4)
21	Existing Generation	0	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
22	Firm Purchases	0	0	0	0	0	0	0	0	0	0
23	New Resources										
24	Renewable	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	0	(387)	1,299	(21)	189	180	137	(67)	(74)	(25)
26	Combined Cycle CT	0	(248)	84	84	(248)	(248)	(248)	84	84	23
27	Coal	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	0	0	0	0	0	0
30	**Total Resources**	0	(635)	1,382	62	(59)	(68)	(111)	17	9	(2)
31	Reserves	0	260	186	10	(23)	(28)	(43)	30	1	2
32	Reserve Margin (RM) (%)	0.0	4.5	0.0	0.0	(0.2)	(0.2)	(0.3)	0.3	(0.0)	0.0

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)

Resource Selections by 10th year, Emissions and Financial Results

	Case Name	Base Case Study	Load Growth Rate Medium Low	Load Growth Rate Medium High	Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices High	High Gas Price Non-firm Prices Med	Lumped Resource Additions	Non-Firm Prices Lower by 25%	Non-Firm Prices Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Annual Energy in Year 2005 (MWa)										
1	Native Load	0	(867)	976	0	0	0	0	0	0	0
2	Pump Storage/Peak Return	0	0	0	0	0	0	0	0	0	0
3	Firm Sales	0	0	0	0	0	0	0	0	0	0
4	Non-Firm Sales	0	57	171	(61)	4	6	(35)	18	(276)	69
5	less DSM	0	159	(102)	49	(24)	(28)	(46)	(12)	6	(3)
6	Total Requirements	0	(651)	1,045	(12)	(20)	(22)	(81)	6	(270)	66
7	Existing Generation	0	(116)	(88)	(96)	(20)	(17)	(53)	15	(254)	62
8	Firm Purchases	0	0	0	0	0	0	0	0	0	0
9	Non-Firm Purchases	0	8	0	20	10	12	27	5	125	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	0	(360)	1,153	(20)	173	165	128	(62)	(71)	(23)
13	Combined Cycle CT	0	(183)	(20)	84	(183)	(183)	(183)	49	(69)	27
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	0	0	0
17	Total Resources	0	(651)	1,045	(12)	(20)	(22)	(81)	6	(270)	66
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	0	-2,250	2,794	-460	219	308	320	-79	-1,004	16
19	NO_x	0	-1	0	-2	1	1	1	0	-4	0
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	0	-3,639	4,574	88	-637	-103	491	-249	898	-996
22	Real Levelized (mills/kWh)	0.00	1.37	-1.24	-0.34	-0.44	0.14	0.89	-0.17	0.84	-0.98
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	0	-3,928	4,858	-17	-545	5	715	-217	895	-993
25	Real Levelized (mills/kWh)	0.00	1.96	-1.43	-0.02	-0.53	0.00	0.68	-0.21	0.85	-0.95
25	**IPM Obj Function (millions $)**	0	-4,269	5,320	-51	-303	-66	628	11	827	-826

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)

Resource Selections by 10th year, Emissions and Financial Results

	Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
								CCCT+2	CCCT+6	CCCT+10
Case Name		25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher
Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
Summer Peak Capacity in Year 2005 (MW)										
1 Native Load	0	0	0	0	0	0	0	0	0	0
2 Firm Sales	0	0	0	0	0	0	0	0	0	0
3 less DSM	0	8	1	1	13	5	5	(1)	(10)	(10)
4 **Total Requirements**	0	8	1	1	13	5	5	(1)	(10)	(10)
5 Existing Generation	0	1	0	(0)	0	(0)	(0)	0	0	0
6 Firm Purchases	0	0	0	0	0	0	0	0	0	0
7 New Resources										
8 Renewable	0	0	0	0	0	0	0	0	0	0
9 Cogeneration	0	(67)	0	8	107	107	107	(278)	(213)	(19)
10 Combined Cycle CT	0	75	1	3	(92)	(102)	(53)	(54)	(120)	(54)
11 Coal	0	0	0	0	0	0	0	0	0	0
12 Transmission	0	0	0	0	0	0	0	0	0	0
13 Peaking Resources	0	0	0	0	0	0	0	331	321	321
14 **Total Resources**	0	9	2	11	14	5	53	(1)	(11)	248
15 Reserves	0	1	0	10	2	0	48	0	(1)	258
16 Reserve Margin (RM) (%)	0.0	0.0	0.0	0.1	0.0	0.0	0.5	0.0	0.0	2.6
Winter Peak Capacity in Year 2005 (MW)										
17 Native Load	0	0	0	0	0	0	0	0	0	0
18 Firm Sales	0	0	0	0	0	0	0	0	0	0
19 less DSM	0	11	2	(1)	17	5	4	2	(12)	(13)
20 **Total Requirements**	0	11	2	(1)	17	5	4	2	(12)	(14)
21 Existing Generation	0	(1)	0	(0)	0	(0)	(0)	(1)	(1)	(1)
22 Firm Purchases	0	0	0	0	0	0	0	0	0	0
23 New Resources										
24 Renewable	0	0	0	0	0	0	0	0	0	0
25 Cogeneration	0	(71)	0	8	113	113	113	(295)	(227)	(21)
26 Combined Cycle CT	0	84	1	4	(103)	(113)	(59)	(60)	(134)	(60)
27 Coal	0	0	0	0	0	0	0	0	0	0
28 Transmission	0	0	0	0	0	0	0	0	0	0
29 Peaking Resources	0	0	0	0	0	0	0	352	342	342
30 **Total Resources**	0	12	2	12	10	0	54	(5)	(19)	260
31 Reserves	0	1	(0)	13	(6)	(5)	50	(6)	(7)	274
32 Reserve Margin (RM) (%)	0.0	(0.0)	(0.0)	0.1	(0.1)	(0.1)	0.5	(0.1)	(0.1)	2.9

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)

Resource Selections by 10th year, Emissions and Financial Results

		Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
									CCCT+2	CCCT+6	CCCT+10
	Case Name		25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher
	Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Annual Energy in Year 2005 (MWa)										
1	Native Load	0	0	0	0	0	0	0	0	0	0
2	Pump Storage/Peak Return	0	0	0	0	0	0	0	0	0	0
3	Firm Sales	0	0	0	0	0	0	0	0	0	0
4	Non-Firm Sales	0	(283)	2	73	(248)	(3)	90	(420)	(226)	87
5	less DSM	0	8	1	0	13	4	4	0	(11)	(11)
6	**Total Requirements**	0	(275)	3	73	(235)	2	94	(419)	(237)	76
7	Existing Generation	0	(254)	0	54	(249)	(26)	23	(248)	10	54
8	Firm Purchases	0	0	0	0	0	0	0	0	0	0
9	Non-Firm Purchases	0	148	2	0	107	6	0	204	49	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	0	(99)	0	8	40	105	105	(275)	(211)	(19)
13	Combined Cycle CT	0	(69)	1	12	(133)	(83)	(34)	(115)	(97)	(33)
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	13	13	75
17	**Total Resources**	0	(275)	3	73	(235)	2	94	(420)	(237)	76
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	0	-1,036	-3	37	-1,099	-54	-31	-845	145	122
19	NO_x	0	-4	0	0	-4	0	0	-3	0	0
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	0	952	38	-885	1,081	207	-781	1,147	405	-841
22	Real Levelized (mills/kWh)	0.00	0.88	0.03	-0.91	0.98	0.18	-0.81	1.13	0.48	-0.76
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	0	942	35	-892	1,061	197	-794	1,156	425	-823
25	Real Levelized (mills/kWh)	0.00	0.90	0.03	-0.86	1.01	0.18	-0.76	1.10	0.40	-0.79
25	**IPM Obj Function (millions $)**	0	879	26	-819	944	63	-796	863	157	-621

Note: (A) An additional 2, 6, or 10 mill/kWh was added to the CCCT cost to represent
an additonal profit margin for an energy producer selling power in a sellers market.

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)

Resource Selections by 10th year, Emissions and Financial Results

		Case Name	Base Case Study	Added Transm: Test Transm Conversion	Added Transm: Bridger to OWC	Added Transm: Utah to OWC	Cheaper Renew-ables	Extend Inputs to 2045: Firm Contracts	Extend Inputs to 2045: Loads and DSM	Extend Inputs to 2045: All Inputs	Environmental Adders with CO2 Costs at: $10/ton	Environmental Adders with CO2 Costs at: $25/ton	Environmental Adders with CO2 Costs at: $40/ton
		Case #	1	57	58	59	61	65	66	67	71	72	73
	Summer Peak Capacity in Year 2005 (MW)												
1	Native Load		0	0	0	0	0	0	0	0	0	0	0
2	Firm Sales		0	0	0	0	0	645	0	645	0	0	0
3	less DSM		0	(49)	(0)	0	4	(17)	21	(20)	(10)	(73)	(107)
4	**Total Requirements**		0	(49)	(0)	0	4	628	21	625	(10)	(73)	(107)
5	Existing Generation		0	0	(0)	0	0	1	0	1	1	1	1
6	Firm Purchases		0	0	0	0	0	268	0	268	0	0	0
7	New Resources												0
8	Renewable		0	0	0	0	54	0	0	0	0	592	876
9	Cogeneration		0	(131)	0	0	(147)	360	(9)	356	622	1,610	1,297
10	Combined Cycle CT		0	75	(0)	0	(102)	75	32	75	75	1,667	2,310
11	Coal		0	0	0	0	0	0	0	0	0	0	0
12	Transmission		0	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources		0	0	0	0	200	0	0	0	0	0	0
14	**Total Resources**		0	(55)	(0)	0	5	703	23	700	697	3,870	4,484
15	Reserves		0	(6)	(0)	0	(35)	76	3	75	707	3,548	4,007
16	Reserve Margin (RM) (%)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.1	40.0	46.8
	Winter Peak Capacity in Year 2005 (MW)												
17	Native Load		0	0	0	0	0	0	0	0	0	0	0
18	Firm Sales		0	0	0	0	0	468	0	468	0	0	0
19	less DSM		0	(41)	1	0	7	(13)	19	(16)	(16)	(63)	(91)
20	**Total Requirements**		0	(41)	1	0	7	455	19	452	(16)	(63)	(91)
21	Existing Generation		0	(1)	(0)	0	0	(1)	0	(1)	(1)	(1)	(1)
22	Firm Purchases		0	0	0	0	0	635	0	635	0	0	0
23	New Resources												
24	Renewable		0	0	0	0	54	0	0	0	0	712	1,166
25	Cogeneration		0	(139)	0	0	(156)	383	(9)	379	661	1,712	1,380
26	Combined Cycle CT		0	84	(0)	0	(114)	84	35	84	84	1,777	2,461
27	Coal		0	0	0	0	0	0	0	0	0	0	0
28	Transmission		0	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources		0	0	0	0	200	0	0	0	0	0	0
30	**Total Resources**		0	(56)	(0)	0	(17)	1,101	26	1,097	744	4,201	5,006
31	Reserves		0	(15)	(1)	0	(24)	646	7	645	760	4,264	5,097
32	Reserve Margin (RM) (%)		0.0	(0.1)	(0.0)	0.0	(0.3)	5.7	0.0	5.7	7.9	44.6	53.4

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)

Resource Selections by 10th year, Emissions and Financial Results

		Base	Added Transm			Cheaper	Extend Inputs to 2045			Environmental Adders with CO2 Costs at		
		Case	Test Transm	Bridger	Utah	Renew-	Firm	Loads and	All			
	Case Name	Study	Conversion	to OWC	to OWC	ables	Contracts	DSM	Inputs	$10/ton	$25/ton	$40/ton
	Case #	1	57	58	59	61	65	66	67	71	72	73
	Annual Energy in Year 2005 (MWa)											
1	Native Load	0	0	0	0	0	0	0	0	0	0	0
2	Pump Storage/Peak Return	0	0	0	0	0	0	0	0	0	(5)	0
3	Firm Sales	0	0	0	0	0	417	0	417	0	0	0
4	Non-Firm Sales	0	(32)	33	4	(9)	50	9	49	(682)	(741)	(638)
5	less DSM	0	(28)	(0)	0	5	(12)	17	(11)	(12)	(43)	(59)
6	**Total Requirements**	0	(60)	33	4	(5)	455	26	455	(693)	(789)	(697)
7	Existing Generation	0	17	19	0	(29)	(44)	8	(42)	(1,876)	(5,315)	(5,770)
8	Firm Purchases	0	0	0	0	0	124	0	124	0	3	3
9	Non-Firm Purchases	0	3	0	4	5	0	4	0	449	627	498
10	New Resources											
11	Renewable	0	0	0	0	51	0	0	0	0	608	956
12	Cogeneration	0	(129)	0	0	(145)	356	(9)	353	615	1,593	1,284
13	Combined Cycle CT	0	50	13	0	(84)	19	22	21	119	1,695	2,331
14	Coal	0	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	198	0	0	0	0	0	0
17	**Total Resources**	0	(60)	33	4	(5)	455	26	456	(693)	(789)	(698)
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO_2	0	-29	132	23	-972	-337	32	-351	-10,277	-30,233	-34,550
19	NO_x	0	0	0	0	0	0	0	0	-34	-93	-103
	Financial Results with End Effects to 2045											
20	50-year Utility Cost											
21	NPV at 8.6% (million $)	0	-683	478	500	-283	-288	2,465	2,581	1,105	9,827	12,991
22	Real Levelized (mills/kWh)	0.00	-0.43	0.48	0.50	-0.36	-0.20	-1.26	-1.02	1.19	10.29	13.61
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	0	-564	479	500	-293	-246	2,483	2,666	1,120	10,037	13,286
25	Real Levelized (mills/kWh)	0.00	-0.54	0.45	0.47	-0.28	-0.24	-1.10	-0.94	1.06	9.58	12.69
25	**IPM Obj Function (millions $)**	0	377	-9	-1	-506	2,957	3,416	7,183	15,573	27,649	37,322

RAMPP-4 Emission Calculation

Name		Emission	MWa	Full Heat	CO2	
Short	Full	Type	(A)	Rate	lbs/mmbtu	1000 Tons (B)
APS	APS Sec CTs	APS-BH		7,600	118	
APT	APS NEW CTs	APS-BH	37	8,530	118	162
BHC	Black Hills CT 1,2,	APS-BH	1	10,334	155	6
CAR	Carbon 1,2	CARBN	159	10,966	198	1,512
CEN	Centralia 1,2	CENTR	576	10,491	213	5,634
CHL	Cholla 4	CHOL4	325	10,548	215	3,233
CLS	Colstrip 3,4	COLST	124	10,659	215	1,247
CRG	Craig 1,2	CRAIG	137	10,058	215	1,296
CRM	Cal Res Margin Unit	GAS	0	7,517	118	0
DJN	Dave Johnston 1,2,3	DJOHN	692	11,083	218	7,328
GDS	Gadsby 1,2,3	GADSB	24	11,662	118	143
HAY	Hayden 1,2	HAYDN	63	10,357	215	614
HER	Hermiston	HERMS	430	6,800	118	1,510
HTN	Huntington 1,2	HUNTN	770	10,169	211	7,237
HTR	Hunter 1,2,3	HUNTR	959	10,332	219	9,509
JBR	Jim Bridger 1,2,3,4	JBRDG	1,249	10,229	211	11,808
JRV	James River	GAS	51	4,381	118	115
LTL	Little Mountain	GAS	9	7,517	118	36
MID	Mid-Columbia	NONE	255			
NAU	Naughton 1,2,3	NAUGH	579	10,518	210	5,604
QFN	QF NW	GAS	61	7,517	118	237
QFU	QF UPL	GAS	61	7,517	118	238
RFF	Request for Proposal	GAS	6	7,517	118	23
WYD	Wyodak	WYODK	243	11,838	215	2,707
	Hydro, Wind and T&D		1,038			
	Total Existing Resources		6,812			60,200

CPU	Summer Purch $6/Year	GAS		7,517	118	
OC1	OWC Cogen 1	GAS	298	7,517	118	1,157
OC2	OWC Cogen 2	GAS	62	7,517	118	241
OCC	OWC Combined Cycle	GAS		7,517	118	
OCT	OWC Simple Cycle CT	GAS		7,517	118	
OGT	OWC Geothermal	NONE		10,000		
OPS	OWC Pump Storage	NONE				
OW1	OWC Wind Non-Firm	NONE				
OW2	OWC Wind Firm	NONE				
UC1	Utah Cogen 1	GAS		7,517	118	
UC2	Utah Cogen 2	GAS		7,517	118	
UCC	Utah Combined Cycle	GAS		7,517	118	
UCT	Utah Simple Cycle CT	GAS		7,517	118	
UCY	Utah IGCC Hunter 4	COALU IG		8,400	206	
UCZ	Utah IGCC CT	COALU IG		8,400	206	
UD1	Utah Gadsby Repower	GAS	319	7,517	118	1,241
UG1	Utah PC Hunter 4	COALU		10,062	206	
UG2	Utah Coal $23.25/Ton	COALU		10,062	206	
UG3	Utah Coal $27.00/Ton	COALU		10,062	206	
UGT	Utah Geothermal	NONE		10,000		
UPC	Utah Compressed Air	NONE		4,700		
UPS	Utah Pumped Storage	NONE				
UW1	Utah Wind Non-firm	NONE				
UW2	Utah Wind Firm	NONE				
WCC	Wyo Combined Cycle	GAS		7,517	118	
WCT	Wyo Simple Cycle CT	GAS		7,517	118	
WCY	Wyo IGCC Wyodak 2	COALW IG		8,881	206	
WCZ	Wyo IGCC CT	COALW IG		8,881	206	
WG1	Wyo PC Wyodak 2	COALW		11,900	206	
WG2	Wyo Coal $6.70/Ton	COALW		10,758	206	
WW1	Wyo Wind Non-firm	NONE				

RAMPP-4 Emission Calculation

Name		Emission	MWa	Full Heat	CO2	
Short	Full	Type	(A)	Rate	lbs/mmbtu	1000 Tons (B)
WW2	Wyo Wind Firm	NONE				
	Total New Resources		679			2.639
	Total On System Emissions		**7,491**			**62,839**
DPH	DSW Sec., HLH	GAS		7,517	118	
DPL	DSW Sec., LLH	GAS		7,517	118	
NPH	NW Sec., HLH	GAS		7,517	118	
NPL	NW Sec., LLH	GAS	4	7,517	118	17
WPH	Wyo Sec., HLH	GAS		7,517	118	
WPL	Wyo Sec., LLH	GAS		7,517	118	
	Total Non-firm Purchases		4			17
ASE	APS Sea Ex(P)	GAS	13	7,517	118	51
ASU	APS Supplemental	GAS		7,517	118	
P37	BPA Spring Ex(P)	NONE	6			
P38	BPA Summer Ex(P)	NONE	14			
CSH	CSPE	NONE				
DES	Deseret	COAL		10,062	206	
GST	Gem State	COAL	6	10,062	206	51
GRT	Grant County	NONE	10			
HAN	Hanford WNP 1	NONE				
ILC	Idaho Load Control	NONE				
INT	Interruptible Rep	GAS		7,517	118	
PGE	PGE Cove	NONE	1			
SCE	SCE Winter	GAS		7,517	118	
SIE	So Idaho Ex(P)	COAL	94	10,062	206	856
TSB	Tri-State Basic	COAL	16	10,062	206	142
TSE	Tri-State Ex(P)	COAL	18	10,062	206	161
USB	USBR Greenspring	NONE				
WWP	WWP	GAS		7,517	118	
P39	WWP Seasonal Ex(P)	GAS	3	7,517	118	12
P40	WWP Summer Purchase	GAS		7,517	118	
	Total Firm Purchases		181			1,273

Total Emissions (Gas Sales)						
	On System Emissions		7,491			62,839
	Purchases		186			1,290
	Firm Sales	GAS	(1,266)	7,517	118	(4,917)
	Non-Firm Sales	GAS	(926)	7,517	118	(3,596)
	Net Total		5,485			55,617

Total Emissions (Coal Sales)						
	On System & Purchases		7,676			64,129
	Firm & Non-Firm Sales	Coal	(2,191)	10,062	206	(19,892)
	Net Total		5,485			44,237

Total Emissions (Weighted)						
	On System & Purchases		7,676			64,129
	Emission per MWa	8.3541				
	Firm Sales		(2,191)			(18,305)
	Net Total		5,485			45,824

Notes
(A) Source Base Case (Case 1) in the year 2005
(B) Formula for 1,000 tons is MWa x 8.760 x Heat Rate x lbs/mmbtu / 2,000,000

Average Annual CO2, NOx and TSP Emissions
Sorted by the absolute percent change in CO2 from the Base Case

Case Number	Study Title	Average Annual Emissions (1,000 Tons)			% Change from Base Case		
		CO2	NOx	TSP	CO2	NOx	TSP
73	High Environmental Adders	20,639	22.3	2.15	-62.6%	-82.2%	-80.8%
72	Medium Environmental Adders	24,956	32.3	2.95	-54.8%	-74.2%	-73.7%
71	Low Environmental Adders	44,911	90.8	8.57	-18.6%	-27.5%	-23.4%
22	Med High Load - Med Gas	57,983	125.5	11.32	5.1%	0.2%	1.2%
21	Med Low Load - Med Gas	52,938	124.3	11.00	-4.1%	-0.7%	-1.6%
47	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	54,090	121.0	10.79	-2.0%	-3.3%	-3.5%
44	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	54,153	121.3	10.81	-1.9%	-3.1%	-3.4%
42	25% Lower Non-Firm Market Prices	54,185	121.4	10.81	-1.8%	-3.0%	-3.3%
61	Renewables at 35% of Capital Cost	54,216	125.0	11.13	-1.8%	-0.1%	-0.5%
50	Underbuild - 25% Lower Non-Firm Market Prices	54,344	121.7	10.82	-1.5%	-2.8%	-3.2%
5	No Turbine Upgrades	54,430	122.9	10.98	-1.4%	-1.9%	-1.8%
11	No DSM	55,921	125.2	11.21	1.3%	0.0%	0.3%
31	Med Load - Low Gas	54,729	123.4	11.01	-0.8%	-1.4%	-1.5%
4	No Summer Season	55,577	125.5	11.20	0.7%	0.2%	0.2%
67	Extension of All Modeling to 2045	54,838	125.4	11.18	-0.6%	0.2%	0.0%
65	Extension of all Existing Firm Wholesale Contracts	54,851	125.4	11.18	-0.6%	0.2%	0.0%
34	High Gas - with Medium Non-firm Market Prices	55,508	126.5	11.25	0.6%	1.1%	0.6%
33	Med Load - High Gas	55,496	126.5	11.26	0.6%	1.1%	0.7%
7	Med Load High Gas Without Hermiston	55,413	126.4	11.26	0.4%	1.0%	0.7%
32	Limited Gas (500 MW) at Med Esc	55,408	126.2	11.24	0.4%	0.8%	0.5%
51	Underbuild - Medium Non-Firm Market Prices	55,334	125.6	11.19	0.3%	0.3%	0.1%
58	Added Transmission - Bridger to OWC	55,320	125.6	11.23	0.2%	0.4%	0.4%
14	15% Conservation Disadvantage	55,315	125.1	11.19	0.2%	-0.1%	0.1%
52	Underbuild - 25% Higher Non-Firm Market Prices	55,310	125.6	11.21	0.2%	0.3%	0.3%
12	20% Conservation Advantage	55,094	125.4	11.18	-0.2%	0.2%	-0.1%
6	Without Hermiston	55,104	125.1	11.19	-0.2%	-0.1%	0.1%
41	Resource Lumpiness	55,109	125.0	11.18	-0.1%	-0.1%	0.0%
13	15% Conservation Advantage	55,118	125.4	11.18	-0.1%	0.2%	0.0%
48	500 MW Plant in 1999 - Medium Non-Firm Market Prices	55,134	125.0	11.15	-0.1%	-0.2%	-0.3%
46	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	55,226	125.3	11.19	0.1%	0.1%	0.1%
66	Extension of Loads & DSM to 2045	55,220	125.2	11.19	0.1%	0.0%	0.0%
49	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	55,157	125.1	11.17	-0.1%	-0.1%	-0.1%
57	Test of Transmission Plant Conversion	55,160	125.3	11.24	-0.1%	0.1%	0.5%
59	Added Transmission - Utah to OWC	55,211	125.3	11.19	0.0%	0.1%	0.1%
43	25% Higher Non-Firm Market Prices	55,205	125.3	11.20	0.0%	0.1%	0.1%
45	250 MW Plant in 1999 - Medium Non-Firm Market Prices	55,186	125.2	11.18	0.0%	0.0%	0.0%
1	Base Case	55,189	125.2	11.18	0.0%	0.0%	0.0%

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PacifiCorp Electric Operations
RAMPP-4
Financial Model Results - Key Output

Loads:

System Load (MWa): The optimization (IPM or integrated planning model) model energy requirement before DSR (conservation) resources are determined. This is the load the company is required to meet through generating resources or purchase power, measured at the busbar. System load includes the gross (including T&D losses) retail energy requirements, plus the regular sales for resale energy requirements (requirement or on-system sales). This excludes the firm wholesale sales energy requirements.

Conservation (MWa): Level of DSR resources selected by the optimization or IPM model from bundles of DSR measures.

System Load After Conservation (MWa): Represents the system load net of conservation.

Energy Sales After Conservation (MWa): The retail energy sales to residential, commercial, and industrial customers, plus the regular sales for resale, measured at the customer meter. The forecasted energy sales before conservation, load growth scenario's were medium low, medium, and medium high.

Total Customers (000): Is the forecast of company customers from the energy sales forecast used in the optimization model.

Net Electric Plant ($M): Adds the optimization model resource additions (completed and CWIP) to total gross electric plant, less accumulated depreciation reserve, in deriving net electric plant. (Net electric plant includes conservation assets, betterment additions, new resource additions from optimization model, less retirements, less accumulated depreciation.)

Net Conservation Assets ($M): The portion of net electric plant from investments in conservation (DSR) resources after cumulative amortization. This includes esc (energy service charge) loan programs and non-esc (deferred) programs.

Utility Cost:

Operating Revenues ($M): (Nominal) Model assumes perfect regulation, where plant betterments are added to rate base in the year completed starting in 2000. The rate base is lagged one year in computing the return on rate base. Depreciation, O&M expenses, taxes other than income taxes, and income taxes are added to return on rate base, providing gross operating revenues. Gross operating revenues are reduced by the revenue credit (sales for resale excluding regular, DSR energy service charge, and other revenues).

Cost in Mills/Kwh: Operating revenues divided by energy sales after conservation (times 1/8760 hours a year times 1000).

Average Customer Bill ($): Operating revenues per customers.

Total Resource Cost:

DSR Customer Cost ($M): (Nominal) Customer investment and benefits from DSR Resources. Includes customer out-of-pocket expenses, O&M expenses or benefits, and replacement cost for measures.

Levelized DSR Customer Cost ($M): Customer cost levelized over 20 years using the company's after-tax discount rate of 8.6%.

Energy Service Charge ($M): Revenue from customers who receive energy service loans for acquiring DSR resources. This reflects the customers total annual loan payments.

Total Resource Cost ($M): (Nominal) Utility operating revenues plus energy service charges and levelized DSR customer costs.

Cost in Mills/Kwh: Total resource cost divided by energy sales before conservation (times 1/8760 hours year times 1000).

Mathematical Computations:

Nominal Dollars are stated in current year values, which includes the impact of inflation.

Real Dollars are nominal values divided by one plus the inflation rate (3.3%) after 1996 to the Year minus Base Year power. Computation removes annual inflation impacts.

NPV is the fifty year net present value of a stream of values discounted at the company's 8.6% after tax discount rate.

Annual Growth Rate calculates the compound annual growth rate over 50 years.

Real Levelized Utility Cost (mills/kwh) is the levelized utility cost using the real discount rate (one plus discount rate divided by one plus the inflation rate), divided by the levelized energy sales after conservation, times one plus the inflation rate. This computes the utility costs on a $/mwh basis without the impact of inflation and allows the company to rank resources when comparing resource additions in different years.

Real Levelized Total Cost (mills/kwh) is the levelized total resource cost using the real discount rate (one plus discount rate divided by one plus the inflation rate), divided by the levelized energy sales before conservation times one plus the inflation rate. This computes the total resource costs on a per mwh basis without the impact of inflation.

PacifiCorp
Financial Analysis
March 16, 1995

Financial Results

Utility Cost Analysis

Case Number	Study Name	Study Title	50-year NPV	50-year Mills	Mills/kWh in 1998	Mills/kWh in 2000	Difference from Base Case NPV	Difference from Base Case Mills	Difference from Base Case 1998	Difference from Base Case 2000
1	base.case	Base Case	$ 42,560	42.55	45.79	44.86	$ -	-	-	-
4	no.summer	No Summer Season	$ 42,284	41.98	45.66	44.65	$ (276)	(0.57)	(0.13)	(0.21)
5	turbine	No Turbine Upgrades	$ 42,610	42.64	46.01	45.23	$ 50	0.09	0.22	0.37
6	herm.mg	Without Hermiston	$ 43,273	43.31	46.32	46.11	$ 712	0.76	0.53	1.25
7	herm.hg	Med Load High Gas Without Hermiston	$ 43,620	43.86	46.30	46.07	$ 1,060	1.31	0.51	1.21
11	no.DSM	No DSM	$ 43,471	41.52	45.37	44.29	$ 910	(1.03)	(0.42)	(0.57)
12	dsm.20dec	20% Conservation Advantage	$ 42,564	43.00	45.88	45.04	$ 4	0.45	0.09	0.18
13	dsm.15dec	15% Conservation Advantage	$ 42,571	42.96	45.83	44.97	$ 11	0.41	0.04	0.11
14	dsm.15inc	15% Conservation Disadvantage	$ 42,578	42.17	45.69	44.69	$ 18	(0.38)	(0.10)	(0.17)
21	ml.mg.pd	Med Low Load - Med Gas	$ 38,921	43.92	47.50	46.77	$ (3,639)	1.37	1.71	1.91
22	mh.mg.pd	Med High Load - Med Gas	$ 47,134	41.31	44.82	43.37	$ 4,574	(1.24)	(0.97)	(1.49)
31	m.lg.pd	Med Load - Low Gas	$ 42,649	42.21	45.79	44.82	$ 88	(0.34)	-	(0.04)
32	limited.500	Limited Gas (500 MW) at Med Esc	$ 41,924	42.11	45.79	44.80	$ (637)	(0.44)	-	(0.06)
33	m.hg.pd	Med Load - High Gas	$ 42,457	42.69	45.79	44.81	$ (103)	0.14	-	(0.05)
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	$ 43,052	43.44	45.83	44.97	$ 491	0.89	0.04	0.11
41	lumpy	Resource Lumpiness	$ 42,312	42.38	45.83	44.91	$ (249)	(0.17)	0.04	0.05
42	nf.lower	25% Lower Non-Firm Market Prices	$ 43,459	43.39	46.30	45.30	$ 898	0.84	0.51	0.44
43	nf.higher	25% Higher Non-Firm Market Prices	$ 41,564	41.57	45.17	43.49	$ (996)	(0.98)	(0.62)	(1.37)
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	$ 43,512	43.43	46.28	46.07	$ 952	0.88	0.49	1.21
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	$ 42,598	42.58	45.79	45.48	$ 38	0.03	-	0.62
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	$ 41,676	41.64	45.16	44.74	$ (885)	(0.91)	(0.63)	(0.12)
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	$ 43,641	43.53	46.27	46.83	$ 1,081	0.98	0.48	1.97
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	$ 42,767	42.73	45.78	46.14	$ 207	0.18	(0.01)	1.28
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	$ 41,779	41.74	45.15	45.36	$ (781)	(0.81)	(0.64)	0.50
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	$ 43,707	43.68	46.32	45.34	$ 1,147	1.13	0.53	0.48
51	under.med	Underbuild - Medium Non-Firm Market Prices	$ 42,966	43.03	45.84	44.91	$ 405	0.48	0.05	0.05
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	$ 41,719	41.79	45.20	44.35	$ (841)	(0.76)	(0.59)	(0.51)
57	tran.uprate	Test of Transmission Plant Conversion	$ 41,877	42.12	45.85	44.96	$ (683)	(0.43)	0.06	0.10
58	tran.bridger	Added Transmission - Bridger to OWC	$ 43,039	43.03	46.01	45.89	$ 478	0.48	0.22	1.03
59	tran.utah	Added Transmission - Utah to OWC	$ 43,060	43.05	46.01	45.90	$ 500	0.50	0.22	1.04
61	renewable	Renewables at 35% of Capital Cost	$ 42,277	42.19	45.51	44.80	$ (283)	(0.36)	(0.28)	(0.06)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	$ 42,273	42.35	46.58	45.16	$ (288)	(0.20)	0.79	0.30
66	extend.loads	Extension of Loads & DSM to 2045	$ 45,026	41.29	45.74	44.77	$ 2,465	(1.26)	(0.05)	(0.09)
67	extend.all	Extension of All Modeling to 2045	$ 45,141	41.53	46.55	45.13	$ 2,581	(1.02)	0.76	0.27
71	low.adders	Low Environmental Adders	$ 43,665	43.74	47.60	46.42	$ 1,105	1.19	1.81	1.56
72	med.adders	Medium Environmental Adders	$ 52,388	52.84	48.58	54.16	$ 9,827	10.29	2.79	9.30
73	high.adders	High Environmental Adders	$ 55,552	56.16	51.69	59.26	$ 12,991	13.61	5.90	14.40

Financial Results
Utility Cost Analysis

Sorted by Mills

Case Number	Study Name	Study Title	50-year NPV	50-year Mills	Mills/kWh in 1998	Mills/kWh in 2000	Difference from Base Case NPV	Difference from Base Case Mills	Difference from Base Case 1998	Difference from Base Case 2000
66	extend.loads	Extension of Loads & DSM to 2045	$ 45,026	41.29	45.74	44.77	$ 2,465	(1.26)	(0.05)	(0.09)
67	extend.all	Extension of All Modeling to 2045	$ 45,141	41.53	46.55	45.13	$ 2,581	(1.02)	0.76	0.27
22	mh.mg.pd	Med High Load - Med Gas	$ 47,134	41.31	44.82	43.37	$ 4,574	(1.24)	(0.97)	(1.49)
11	no.DSM	No DSM	$ 43,471	41.52	45.37	44.29	$ 910	(1.03)	(0.42)	(0.57)
43	nf.higher	25% Higher Non-Firm Market Prices	$ 41,564	41.57	45.17	43.49	$ (996)	(0.98)	(0.62)	(1.37)
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	$ 41,676	41.64	45.16	44.74	$ (885)	(0.91)	(0.63)	(0.12)
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	$ 41,779	41.74	45.15	45.36	$ (781)	(0.81)	(0.64)	0.50
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	$ 41,719	41.79	45.20	44.35	$ (841)	(0.76)	(0.59)	(0.51)
4	no.summer	No Summer Season	$ 42,284	41.98	45.66	44.65	$ (276)	(0.57)	(0.13)	(0.21)
32	limited.500	Limited Gas (500 MW) at Med Esc	$ 41,924	42.11	45.79	44.80	$ (637)	(0.44)	-	(0.06)
57	tran.uprate	Test of Transmission Plant Conversion	$ 41,877	42.12	45.85	44.96	$ (683)	(0.43)	0.06	0.10
14	dsm.15inc	15% Conservation Disadvantage	$ 42,578	42.17	45.69	44.69	$ 18	(0.38)	(0.10)	(0.17)
61	renewable	Renewables at 35% of Capital Cost	$ 42,277	42.19	45.51	44.80	$ (283)	(0.36)	(0.28)	(0.06)
31	m.lg.pd	Med Load - Low Gas	$ 42,649	42.21	45.79	44.82	$ 88	(0.34)	-	(0.04)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	$ 42,273	42.35	46.58	45.16	$ (288)	(0.20)	0.79	0.30
41	lumpy	Resource Lumpiness	$ 42,312	42.38	45.83	44.91	$ (249)	(0.17)	0.04	0.05
1	base.case	Base Case	$ 42,560	42.55	45.79	44.86	$ -	-	-	-
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	$ 42,598	42.58	45.79	45.48	$ 38	0.03	-	0.62
5	turbine	No Turbine Upgrades	$ 42,610	42.64	46.01	45.23	$ 50	0.09	0.22	0.37
33	m.hg.pd	Med Load - High Gas	$ 42,457	42.69	45.79	44.81	$ (103)	0.14	-	(0.05)
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	$ 42,767	42.73	45.78	46.14	$ 207	0.18	(0.01)	1.28
13	dsm.15dec	15% Conservation Advantage	$ 42,571	42.96	45.83	44.97	$ 11	0.41	0.04	0.11
12	dsm.20dec	20% Conservation Advantage	$ 42,564	43.00	45.88	45.04	$ 4	0.45	0.09	0.18
51	under.med	Underbuild - Medium Non-Firm Market Prices	$ 42,966	43.03	45.84	44.91	$ 405	0.48	0.05	0.05
58	tran.bridger	Added Transmission - Bridger to OWC	$ 43,039	43.03	46.01	45.89	$ 478	0.48	0.22	1.03
59	tran.utah	Added Transmission - Utah to OWC	$ 43,060	43.05	46.01	45.90	$ 500	0.50	0.22	1.04
6	herm.mg	Without Hermiston	$ 43,273	43.31	46.32	46.11	$ 712	0.76	0.53	1.25
42	nf.lower	25% Lower Non-Firm Market Prices	$ 43,459	43.39	46.30	45.30	$ 898	0.84	0.51	0.44
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	$ 43,512	43.43	46.28	46.07	$ 952	0.88	0.49	1.21
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	$ 43,052	43.44	45.83	44.97	$ 491	0.89	0.04	0.11
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	$ 43,641	43.53	46.27	46.83	$ 1,081	0.98	0.48	1.97
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	$ 43,707	43.68	46.32	45.34	$ 1,147	1.13	0.53	0.48
71	low.adders	Low Environmental Adders	$ 43,665	43.74	47.60	46.42	$ 1,105	1.19	1.81	1.56
7	herm.hg	Med Load High Gas Without Hermiston	$ 43,620	43.86	46.30	46.07	$ 1,060	1.31	0.51	1.21
21	ml.mg.pd	Med Low Load - Med Gas	$ 38,921	43.92	47.50	46.77	$ (3,639)	1.37	1.71	1.91
72	med.adders	Medium Environmental Adders	$ 52,388	52.84	48.58	54.16	$ 9,827	10.29	2.79	9.30
73	high.adders	High Environmental Adders	$ 55,552	56.16	51.69	59.26	$ 12,991	13.61	5.90	14.40

Financial Results

Total Resource Cost Analysis

Case Number	Study Name	Study Title	50-year NPV	50-year Mills	Mills/kWh in 1998	Mills/kWh in 2000	Difference from Base Case NPV	Difference from Base Case Mills	Difference from Base Case 1998	Difference from Base Case 2000
1	base.case	Base Case	$ 42,990	41.07	45.54	44.38	$ -	-	-	-
4	no.summer	No Summer Season	$ 42,610	40.70	45.48	44.29	$ (381)	(0.37)	(0.06)	(0.09)
5	turbine	No Turbine Upgrades	$ 43,052	41.12	45.75	44.73	$ 62	0.05	0.21	0.35
6	herm.mg	Without Hermiston	$ 43,716	41.76	46.05	45.58	$ 726	0.69	0.51	1.20
7	herm.hg	Med Load High Gas Without Hermiston	$ 44,158	42.18	46.02	45.52	$ 1,168	1.11	0.48	1.14
11	no.DSM	No DSM	$ 43,471	41.52	45.37	44.29	$ 481	0.45	(0.17)	(0.09)
12	dsm.20dec	20% Conservation Advantage	$ 43,259	41.32	45.62	44.53	$ 269	0.25	0.08	0.15
13	dsm.15dec	15% Conservation Advantage	$ 43,225	41.29	45.57	44.45	$ 235	0.22	0.03	0.07
14	dsm.15inc	15% Conservation Disadvantage	$ 42,905	40.98	45.51	44.33	$ (85)	(0.09)	(0.03)	(0.05)
21	ml.mg.pd	Med Low Load - Med Gas	$ 39,062	43.03	47.39	46.58	$ (3,928)	1.96	1.85	2.20
22	mh.mg.pd	Med High Load - Med Gas	$ 47,849	39.64	44.51	42.80	$ 4,858	(1.43)	(1.03)	(1.58)
31	m.lg.pd	Med Load - Low Gas	$ 42,973	41.05	45.58	44.43	$ (17)	(0.02)	0.04	0.05
32	limited.500	Limited Gas (500 MW) at Med Esc	$ 42,445	40.54	45.52	44.29	$ (545)	(0.53)	(0.02)	(0.09)
33	m.hg.pd	Med Load - High Gas	$ 42,995	41.07	45.52	44.29	$ 5	-	(0.02)	(0.09)
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	$ 43,705	41.75	45.56	44.45	$ 715	0.68	0.02	0.07
41	lumpy	Resource Lumpiness	$ 42,773	40.86	45.56	44.40	$ (217)	(0.21)	0.02	0.02
42	nf.lower	25% Lower Non-Firm Market Prices	$ 43,885	41.92	46.06	44.83	$ 895	0.85	0.52	0.45
43	nf.higher	25% Higher Non-Firm Market Prices	$ 41,998	40.12	44.92	43.02	$ (993)	(0.95)	(0.62)	(1.36)
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	$ 43,932	41.97	46.05	45.59	$ 942	0.90	0.51	1.21
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	$ 43,025	41.10	45.54	44.99	$ 35	0.03	-	0.61
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	$ 42,098	40.21	44.92	44.26	$ (892)	(0.86)	(0.62)	(0.12)
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	$ 44,051	42.08	46.04	46.35	$ 1,061	1.01	0.50	1.97
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	$ 43,187	41.25	45.54	45.65	$ 197	0.18	-	1.27
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	$ 42,196	40.31	44.91	44.87	$ (794)	(0.76)	(0.63)	0.49
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	$ 44,146	42.17	46.07	44.85	$ 1,156	1.10	0.53	0.47
51	under.med	Underbuild - Medium Non-Firm Market Prices	$ 43,415	41.47	45.56	44.40	$ 425	0.40	0.02	0.02
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	$ 42,167	40.28	44.93	43.85	$ (823)	(0.79)	(0.61)	(0.53)
57	tran.uprate	Test of Transmission Plant Conversion	$ 42,426	40.53	45.57	44.43	$ (564)	(0.54)	0.03	0.05
58	tran.bridger	Added Transmission - Bridger to OWC	$ 43,469	41.52	45.75	45.39	$ 479	0.45	0.21	1.01
59	tran.utah	Added Transmission - Utah to OWC	$ 43,490	41.54	45.76	45.40	$ 500	0.47	0.22	1.02
61	renewable	Renewables at 35% of Capital Cost	$ 42,698	40.79	45.27	44.34	$ (293)	(0.28)	(0.27)	(0.04)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	$ 42,744	40.83	46.31	44.65	$ (246)	(0.24)	0.77	0.27
66	extend.loads	Extension of Loads & DSM to 2045	$ 45,473	39.97	45.52	44.35	$ 2,483	(1.10)	(0.02)	(0.03)
67	extend.all	Extension of All Modeling to 2045	$ 45,656	40.13	46.29	44.64	$ 2,666	(0.94)	0.75	0.26
71	low.adders	Low Environmental Adders	$ 44,110	42.13	47.30	45.87	$ 1,120	1.06	1.76	1.49
72	med.adders	Medium Environmental Adders	$ 53,027	50.65	48.29	53.45	$ 10,037	9.58	2.75	9.07
73	high.adders	High Environmental Adders	$ 56,276	53.76	51.36	58.41	$ 13,286	12.69	5.82	14.03

Financial Results
Total Resource Cost Analysis

Sorted by Mills

Case Number	Study Name	Study Title	50-year NPV	50-year Mills	Mills/kWh in 1998	Mills/kWh in 2000	Difference from Base Case NPV	Difference from Base Case Mills	Difference from Base Case 1998	Difference from Base Case 2000
66	extend.loads	Extension of Loads & DSM to 2045	$ 45,473	39.97	45.52	44.35	$ 2,483	(1.10)	(0.02)	(0.03)
67	extend.all	Extension of All Modeling to 2045	$ 45,656	40.13	46.29	44.64	$ 2,666	(0.94)	0.75	0.26
22	mh.mg.pd	Med High Load - Med Gas	$ 47,849	39.64	44.51	42.80	$ 4,858	(1.43)	(1.03)	(1.58)
43	nf.higher	25% Higher Non-Firm Market Prices	$ 41,998	40.12	44.92	43.02	$ (993)	(0.95)	(0.62)	(1.36)
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	$ 42,098	40.21	44.92	44.26	$ (892)	(0.86)	(0.62)	(0.12)
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	$ 42,167	40.28	44.93	43.85	$ (823)	(0.79)	(0.61)	(0.53)
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	$ 42,196	40.31	44.91	44.87	$ (794)	(0.76)	(0.63)	0.49
57	tran.uprate	Test of Transmission Plant Conversion	$ 42,426	40.53	45.57	44.43	$ (564)	(0.54)	0.03	0.05
32	limited.500	Limited Gas (500 MW) at Med Esc	$ 42,445	40.54	45.52	44.29	$ (545)	(0.53)	(0.02)	(0.09)
4	no.summer	No Summer Season	$ 42,610	40.70	45.48	44.29	$ (381)	(0.37)	(0.06)	(0.09)
61	renewable	Renewables at 35% of Capital Cost	$ 42,698	40.79	45.27	44.34	$ (293)	(0.28)	(0.27)	(0.04)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	$ 42,744	40.83	46.31	44.65	$ (246)	(0.24)	0.77	0.27
41	lumpy	Resource Lumpiness	$ 42,773	40.86	45.56	44.40	$ (217)	(0.21)	0.02	0.02
14	dsm.15inc	15% Conservation Disadvantage	$ 42,905	40.98	45.51	44.33	$ (85)	(0.09)	(0.03)	(0.05)
31	m.lg.pd	Med Load - Low Gas	$ 42,973	41.05	45.58	44.43	$ (17)	(0.02)	0.04	0.05
1	**base.case**	**Base Case**	**$ 42,990**	**41.07**	**45.54**	**44.38**	**$ -**	**-**	**-**	**-**
33	m.hg.pd	Med Load - High Gas	$ 42,995	41.07	45.52	44.29	$ 5	-	(0.02)	(0.09)
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	$ 43,025	41.10	45.54	44.99	$ 35	0.03	-	0.61
5	turbine	No Turbine Upgrades	$ 43,052	41.12	45.75	44.73	$ 62	0.05	0.21	0.35
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	$ 43,187	41.25	45.54	45.65	$ 197	0.18	-	1.27
13	dsm.15dec	15% Conservation Advantage	$ 43,225	41.29	45.57	44.45	$ 235	0.22	0.03	0.07
12	dsm.20dec	20% Conservation Advantage	$ 43,259	41.32	45.62	44.53	$ 269	0.25	0.08	0.15
51	under.med	Underbuild - Medium Non-Firm Market Prices	$ 43,415	41.47	45.56	44.40	$ 425	0.40	0.02	0.02
11	no.DSM	No DSM	$ 43,471	41.52	45.37	44.29	$ 481	0.45	(0.17)	(0.09)
58	tran.bridger	Added Transmission - Bridger to OWC	$ 43,469	41.52	45.75	45.39	$ 479	0.45	0.21	1.01
59	tran.utah	Added Transmission - Utah to OWC	$ 43,490	41.54	45.76	45.40	$ 500	0.47	0.22	1.02
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	$ 43,705	41.75	45.56	44.45	$ 715	0.68	0.02	0.07
6	herm.mg	Without Hermiston	$ 43,716	41.76	46.05	45.58	$ 726	0.69	0.51	1.20
42	nf.lower	25% Lower Non-Firm Market Prices	$ 43,885	41.92	46.06	44.83	$ 895	0.85	0.52	0.45
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	$ 43,932	41.97	46.05	45.59	$ 942	0.90	0.51	1.21
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	$ 44,051	42.08	46.04	46.35	$ 1,061	1.01	0.50	1.97
71	low.adders	Low Environmental Adders	$ 44,110	42.13	47.30	45.87	$ 1,120	1.06	1.76	1.49
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	$ 44,146	42.17	46.07	44.85	$ 1,156	1.10	0.53	0.47
7	herm.hg	Med Load High Gas Without Hermiston	$ 44,158	42.18	46.02	45.52	$ 1,168	1.11	0.48	1.14
21	ml.mg.pd	Med Low Load - Med Gas	$ 39,062	43.03	47.39	46.58	$ (3,928)	1.96	1.85	2.20
72	med.adders	Medium Environmental Adders	$ 53,027	50.65	48.29	53.45	$ 10,037	9.58	2.75	9.07
73	high.adders	High Environmental Adders	$ 56,276	53.76	51.36	58.41	$ 13,286	12.69	5.82	14.03

50-Year Utility and Total Resource Cost
Change from the Base Case

Case Number	Study Title	Utility Cost				Total Resource Cost			
		50-Year NPV	Real Levelized Mills/kWh	Δ from Base Case (1) NPV	Δ from Base Case (1) Mills/kWh	50-Year NPV	Real Levelized Mills/kWh	Δ from Base Case (1) NPV	Δ from Base Case (1) Mills/kWh
1	Base Case	42,560	42.55	0.0%	0.0%	42,990	41.07	0.0%	0.0%
4	No Summer Season	42,284	41.98	-0.6%	-1.3%	42,610	40.70	-0.9%	-0.9%
5	No Turbine Upgrades	42,610	42.64	0.1%	0.2%	43,052	41.12	0.1%	0.1%
6	Without Hermiston	43,273	43.31	1.7%	1.8%	43,716	41.76	1.7%	1.7%
7	Med Load High Gas Without Hermiston	43,620	43.86	2.5%	3.1%	44,158	42.18	2.7%	2.7%
11	No DSM	43,471	41.52	2.1%	-2.4%	43,471	41.52	1.1%	1.1%
12	20% Conservation Advantage	42,564	43.00	0.0%	1.1%	43,259	41.32	0.6%	0.6%
13	15% Conservation Advantage	42,571	42.96	0.0%	1.0%	43,225	41.29	0.5%	0.5%
14	15% Conservation Disadvantage	42,578	42.17	0.0%	-0.9%	42,905	40.98	-0.2%	-0.2%
21	Med Low Load - Med Gas	38,921	43.92	-8.6%	3.2%	39,062	43.03	-9.1%	4.8%
22	Med High Load - Med Gas	47,134	41.31	10.7%	-2.9%	47,849	39.64	11.3%	-3.5%
31	Med Load - Low Gas	42,649	42.21	0.2%	-0.8%	42,973	41.05	0.0%	0.0%
32	Limited Gas (500 MW) at Med Esc	41,924	42.11	-1.5%	-1.0%	42,445	40.54	-1.3%	-1.3%
33	Med Load - High Gas	42,457	42.69	-0.2%	0.3%	42,995	41.07	0.0%	0.0%
34	High Gas - with Medium Non-firm Market Prices	43,052	43.44	1.2%	2.1%	43,705	41.75	1.7%	1.7%
41	Resource Lumpiness	42,312	42.38	-0.6%	-0.4%	42,773	40.86	-0.5%	-0.5%
42	25% Lower Non-Firm Market Prices	43,459	43.39	2.1%	2.0%	43,885	41.92	2.1%	2.1%
43	25% Higher Non-Firm Market Prices	41,564	41.57	-2.3%	-2.3%	41,998	40.12	-2.3%	-2.3%
44	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	43,512	43.43	2.2%	2.1%	43,932	41.97	2.2%	2.2%
45	250 MW Plant in 1999 - Medium Non-Firm Market Prices	42,598	42.58	0.1%	0.1%	43,025	41.10	0.1%	0.1%
46	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	41,676	41.64	-2.1%	-2.1%	42,098	40.21	-2.1%	-2.1%
47	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	43,641	43.53	2.5%	2.3%	44,051	42.08	2.5%	2.5%
48	500 MW Plant in 1999 - Medium Non-Firm Market Prices	42,767	42.73	0.5%	0.4%	43,187	41.25	0.5%	0.4%
49	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	41,779	41.74	-1.8%	-1.9%	42,196	40.31	-1.8%	-1.9%
50	Underbuild - 25% Lower Non-Firm Market Prices	43,707	43.68	2.7%	2.7%	44,146	42.17	2.7%	2.7%
51	Underbuild - Medium Non-Firm Market Prices	42,966	43.03	1.0%	1.1%	43,415	41.47	1.0%	1.0%
52	Underbuild - 25% Higher Non-Firm Market Prices	41,719	41.79	-2.0%	-1.8%	42,167	40.28	-1.9%	-1.9%
57	Test of Transmission Plant Conversion	41,877	42.12	-1.6%	-1.0%	42,426	40.53	-1.3%	-1.3%
58	Added Transmission - Bridger to OWC	43,039	43.03	1.1%	1.1%	43,469	41.52	1.1%	1.1%
59	Added Transmission - Utah to OWC	43,060	43.05	1.2%	1.2%	43,490	41.54	1.2%	1.1%
61	Renewables at 35% of Capital Cost	42,277	42.19	-0.7%	-0.8%	42,698	40.79	-0.7%	-0.7%
65	Extension of all Existing Firm Wholesale Contracts	42,273	42.35	-0.7%	-0.5%	42,744	40.83	-0.6%	-0.6%
66	Extension of Loads & DSM to 2045	45,093	40.69	6.0%	-4.4%	45,540	39.41	5.9%	-4.0%
67	Extension of All Modeling to 2045	45,208	40.92	6.2%	-3.8%	45,723	39.57	6.4%	-3.7%
71	Low Environmental Adders	43,665	43.74	2.6%	2.8%	44,110	42.13	2.6%	2.6%
72	Medium Environmental Adders	52,388	52.84	23.1%	24.2%	53,027	50.65	23.3%	23.3%
73	High Environmental Adders	55,552	56.16	30.5%	32.0%	56,276	53.76	30.9%	30.9%

(1) Δ from Average = [(Value / Average) -1]

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Gas Fired Base Load Resources Selected by Year

Summer Incremental MW

Case Number	Study Name	Study Title	Study Year						Total
			1999	2000	2001	2002	2003	2005	MW
1	base.case	Base Case	-	-	-	13	318	254	586
4	no.summer	No Summer Season	-	-	-	-	162	171	333
5	turbine	No Turbine Upgrades	-	-	-	100	375	253	728
6	herm.mg	Without Hermiston	-	-	-	207	552	253	1,012
7	herm.hg	Med Load High Gas Without Hermiston	-	-	-	150	575	241	966
11	no.DSM	No DSM	-	-	-	121	525	334	980
12	dsm.20dec	20% Conservation Advantage	-	-	-	-	245	231	476
13	dsm.15dec	15% Conservation Advantage	-	-	-	-	261	231	492
14	dsm.15inc	15% Conservation Disadvantage	-	-	-	39	345	264	648
21	ml.mg.pd	Med Low Load - Med Gas	-	-	-	-	-	-	-
22	mh.mg.pd	Med High Load - Med Gas	-	221	97	303	798	463	1,882
31	m.lg.pd	Med Load - Low Gas	-	1	-	128	246	266	641
32	limited.500	Limited Gas (500 MW) at Med Esc	-	-	-	100	198	243	541
33	m.hg.pd	Med Load - High Gas	-	-	-	88	203	241	532
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	-	-	-	-	261	231	493
41	lumpy	Resource Lumpiness	-	-	-	76	242	280	598
42	nf.lower	25% Lower Non-Firm Market Prices	-	-	-	-	337	254	591
43	nf.higher	25% Higher Non-Firm Market Prices	-	146	120	94	184	39	583
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	235	-	-	-	105	254	594
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	235	-	-	-	99	254	587
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	235	5	47	71	236	3	597
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	470	-	-	-	-	130	600
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	470	-	-	-	-	121	591
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	470	-	-	-	135	34	639
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	-	-	-	-	-	254	254
51	under.med	Underbuild - Medium Non-Firm Market Prices	-	-	-	-	-	253	253
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	-	-	-	-	-	512	512
57	tran.uprate	Test of Transmission Plant Conversion	-	-	-	-	291	240	530
58	tran.bridger	Added Transmission - Bridger to OWC	-	-	-	14	318	254	586
59	tran.utah	Added Transmission - Utah to OWC	-	-	-	13	318	254	586
61	renewable	Renewables at 35% of Capital Cost	-	-	-	-	136	200	336
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	-	-	-	57	516	447	1,020
66	extend.loads	Extension of Loads & DSM to 2045	-	-	-	30	326	253	609
67	extend.all	Extension of All Modeling to 2045	-	-	-	65	524	428	1,017
71	low.adders	Low Environmental Adders	-	603	477	-	203	-	1,282
72	med.adders	Medium Environmental Adders	-	1,840	1,342	669	11	-	3,863
73	high.adders	High Environmental Adders	-	1,840	1,553	468	298	35	4,193

Gas Fired Base Load Resources Selected by Year (Case XX less Case 1)

Summer Incremental MW

Case Number	Study Name	Study Title	Study Year 1999	2000	2001	2002	2003	2005	Total MW
1	base.case	Base Case	-	-	-	-	-	-	-
4	no.summer	No Summer Season	-	-	-	(13)	(156)	(83)	(253)
5	turbine	No Turbine Upgrades	-	-	-	86	57	(1)	142
6	herm.mg	Without Hermiston	-	-	-	194	234	(1)	426
7	herm.hg	Med Load High Gas Without Hermiston	-	-	-	137	257	(13)	381
11	no.DSM	No DSM	-	-	-	107	207	81	395
12	dsm.20dec	20% Conservation Advantage	-	-	-	(13)	(73)	(23)	(109)
13	dsm.15dec	15% Conservation Advantage	-	-	-	(13)	(58)	(23)	(94)
14	dsm.15inc	15% Conservation Disadvantage	-	-	-	26	27	10	63
21	ml.mg.pd	Med Low Load - Med Gas	-	-	-	(13)	(318)	(254)	(586)
22	mh.mg.pd	Med High Load - Med Gas	-	221	97	290	480	209	1,296
31	m.lg.pd	Med Load - Low Gas	-	1	-	115	(72)	12	56
32	limited.500	Limited Gas (500 MW) at Med Esc	-	-	-	87	(121)	(11)	(44)
33	m.hg.pd	Med Load - High Gas	-	-	-	75	(115)	(13)	(53)
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	-	-	-	(13)	(57)	(23)	(93)
41	lumpy	Resource Lumpiness	-	-	-	63	(77)	26	13
42	nf.lower	25% Lower Non-Firm Market Prices	-	-	-	(13)	19	1	6
43	nf.higher	25% Higher Non-Firm Market Prices	-	146	120	81	(135)	(214)	(3)
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	235	-	-	(13)	(214)	0	8
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	235	-	-	(13)	(220)	(0)	2
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	235	5	47	58	(83)	(251)	11
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	470	-	-	(13)	(318)	(124)	14
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	470	-	-	(13)	(318)	(133)	5
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	470	-	-	(13)	(183)	(220)	53
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	-	-	-	(13)	(318)	0	(332)
51	under.med	Underbuild - Medium Non-Firm Market Prices	-	-	-	(13)	(318)	(1)	(333)
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	-	-	-	(13)	(318)	258	(73)
57	tran.uprate	Test of Transmission Plant Conversion	-	-	-	(13)	(28)	(14)	(55)
58	tran.bridger	Added Transmission - Bridger to OWC	-	-	-	0	-	(0)	-
59	tran.utah	Added Transmission - Utah to OWC	-	-	-	-	-	-	-
61	renewable	Renewables at 35% of Capital Cost	-	-	-	(13)	(182)	(53)	(249)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	-	-	-	44	198	193	435
66	extend.loads	Extension of Loads & DSM to 2045	-	-	-	17	8	(1)	23
67	extend.all	Extension of All Modeling to 2045	-	-	-	51	206	175	432
71	low.adders	Low Environmental Adders	-	603	477	(13)	(116)	(254)	697
72	med.adders	Medium Environmental Adders	-	1,840	1,342	656	(307)	(254)	3,277
73	high.adders	High Environmental Adders	-	1,840	1,553	454	(21)	(219)	3,607

Gas Fired Base Load Resources Selected by Year

Winter Incremental MW

Case Number	Study Name	Study Title	Study Year 1999	2000	2001	2002	2003	2005	Total MW
1	base.case	Base Case	-	-	-	15	347	272	634
4	no.summer	No Summer Season	-	-	-	-	162	171	333
5	turbine	No Turbine Upgrades	-	-	-	111	408	271	789
6	herm.mg	Without Hermiston	-	-	-	223	596	272	1,091
7	herm.hg	Med Load High Gas Without Hermiston	-	-	-	160	612	256	1,028
11	no.DSM	No DSM	-	-	-	135	567	356	1,058
12	dsm.20dec	20% Conservation Advantage	-	-	-	-	266	246	512
13	dsm.15dec	15% Conservation Advantage	-	-	-	-	283	246	529
14	dsm.15inc	15% Conservation Disadvantage	-	-	-	44	375	285	704
21	ml.mg.pd	Med Low Load - Med Gas	-	-	-	-	-	-	-
22	mh.mg.pd	Med High Load - Med Gas	-	244	108	324	849	493	2,017
31	m.lg.pd	Med Load - Low Gas	-	1	-	143	270	283	697
32	limited.500	Limited Gas (500 MW) at Med Esc	-	-	-	107	210	259	576
33	m.hg.pd	Med Load - High Gas	-	-	-	94	216	256	566
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	-	-	-	-	278	246	524
41	lumpy	Resource Lumpiness	-	-	-	85	262	304	651
42	nf.lower	25% Lower Non-Firm Market Prices	-	-	-	-	367	277	644
43	nf.higher	25% Higher Non-Firm Market Prices	-	161	127	101	201	42	633
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	250	-	-	-	117	280	647
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	250	-	-	-	110	276	636
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	250	6	52	80	256	3	646
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	500	-	-	-	-	145	645
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	500	-	-	-	-	134	634
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	500	-	-	-	151	37	688
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	-	-	-	-	-	279	279
51	under.med	Underbuild - Medium Non-Firm Market Prices	-	-	-	-	-	274	274
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	-	-	-	-	-	553	553
57	tran.uprate	Test of Transmission Plant Conversion	-	-	-	-	316	263	579
58	tran.bridger	Added Transmission - Bridger to OWC	-	-	-	15	347	272	634
59	tran.utah	Added Transmission - Utah to OWC	-	-	-	15	347	272	634
61	renewable	Renewables at 35% of Capital Cost	-	-	-	-	151	213	364
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	-	-	-	64	557	479	1,101
66	extend.loads	Extension of Loads & DSM to 2045	-	-	-	33	355	272	660
67	extend.all	Extension of All Modeling to 2045	-	-	-	72	566	459	1,097
71	low.adders	Low Environmental Adders	-	650	514	-	215	-	1,379
72	med.adders	Medium Environmental Adders	-	1,966	1,434	712	12	-	4,124
73	high.adders	High Environmental Adders	-	1,966	1,658	497	317	37	4,475

Gas Fired Base Load Resources Selected by Year (Case XX less Case 1)

Winter Incremental MW

Case Number	Study Name	Study Title	Study Year 1999	2000	2001	2002	2003	2005	Total MW
1	base.case	Base Case	-	-	-	-	-	-	-
4	no.summer	No Summer Season	-	-	-	(15)	(185)	(101)	(301)
5	turbine	No Turbine Upgrades	-	-	-	96	60	(1)	155
6	herm.mg	Without Hermiston	-	-	-	208	249	1	457
7	herm.hg	Med Load High Gas Without Hermiston	-	-	-	145	265	(16)	394
11	no.DSM	No DSM	-	-	-	120	220	84	424
12	dsm.20dec	20% Conservation Advantage	-	-	-	(15)	(81)	(26)	(122)
13	dsm.15dec	15% Conservation Advantage	-	-	-	(15)	(64)	(26)	(105)
14	dsm.15inc	15% Conservation Disadvantage	-	-	-	29	28	13	70
21	ml.mg.pd	Med Low Load - Med Gas	-	-	-	(15)	(347)	(272)	(634)
22	mh.mg.pd	Med High Load - Med Gas	-	244	108	309	502	221	1,383
31	m.lg.pd	Med Load - Low Gas	-	1	-	128	(77)	11	63
32	limited.500	Limited Gas (500 MW) at Med Esc	-	-	-	92	(137)	(13)	(59)
33	m.hg.pd	Med Load - High Gas	-	-	-	79	(131)	(16)	(68)
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	-	-	-	(15)	(69)	(26)	(110)
41	lumpy	Resource Lumpiness	-	-	-	70	(85)	32	17
42	nf.lower	25% Lower Non-Firm Market Prices	-	-	-	(15)	20	5	10
43	nf.higher	25% Higher Non-Firm Market Prices	-	161	127	86	(147)	(230)	(2)
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	250	-	-	(15)	(231)	8	13
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	250	-	-	(15)	(237)	4	2
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	250	6	52	65	(91)	(269)	12
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	500	-	-	(15)	(347)	(127)	10
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	500	-	-	(15)	(347)	(138)	0
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	500	-	-	(15)	(196)	(234)	54
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	-	-	-	(15)	(347)	7	(356)
51	under.med	Underbuild - Medium Non-Firm Market Prices	-	-	-	(15)	(347)	2	(360)
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	-	-	-	(15)	(347)	281	(81)
57	tran.uprate	Test of Transmission Plant Conversion	-	-	-	(15)	(31)	(9)	(55)
58	tran.bridger	Added Transmission - Bridger to OWC	-	-	-	-	-	-	-
59	tran.utah	Added Transmission - Utah to OWC	-	-	-	-	-	-	-
61	renewable	Renewables at 35% of Capital Cost	-	-	-	(15)	(197)	(59)	(270)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	-	-	-	49	210	207	466
66	extend.loads	Extension of Loads & DSM to 2045	-	-	-	18	8	(0)	26
67	extend.all	Extension of All Modeling to 2045	-	-	-	57	219	187	463
71	low.adders	Low Environmental Adders	-	650	514	(15)	(132)	(272)	745
72	med.adders	Medium Environmental Adders	-	1,966	1,434	697	(335)	(272)	3,490
73	high.adders	High Environmental Adders	-	1,966	1,658	482	(31)	(235)	3,841

Gas Fired Base Load Resources Selected by Year

Energy MWa

Case Number	Study Name	Study Title	Study Year					
			1999	2000	2001	2002	2003	2005
1	base.case	Base Case	-	-	-	11	291	543
4	no.summer	No Summer Season	-	-	-	-	122	269
5	turbine	No Turbine Upgrades	-	-	-	83	420	669
6	herm.mg	Without Hermiston	-	-	-	196	701	940
7	herm.hg	Med Load High Gas Without Hermiston	-	-	-	149	716	951
11	no.DSM	No DSM	-	-	-	101	578	893
12	dsm.20dec	20% Conservation Advantage	-	-	-	-	226	455
13	dsm.15dec	15% Conservation Advantage	-	-	-	-	240	470
14	dsm.15inc	15% Conservation Disadvantage	-	-	-	33	338	584
21	ml.mg.pd	Med Low Load - Med Gas	-	-	-	-	-	-
22	mh.mg.pd	Med High Load - Med Gas	-	205	290	572	1,310	1,676
31	m.lg.pd	Med Load - Low Gas	-	1	1	112	332	606
32	limited.500	Limited Gas (500 MW) at Med Esc	-	-	-	99	295	533
33	m.hg.pd	Med Load - High Gas	-	-	-	87	289	525
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	-	-	-	-	259	488
41	lumpy	Resource Lumpiness	-	-	-	61	281	530
42	nf.lower	25% Lower Non-Firm Market Prices	-	-	-	-	229	402
43	nf.higher	25% Higher Non-Firm Market Prices	-	132	250	334	488	547
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	200	200	200	200	240	374
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	229	233	233	233	315	544
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	228	237	279	336	537	562
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	400	400	400	400	400	449
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	444	444	444	465	465	565
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	444	444	444	465	570	614
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	-	-	-	-	-	153
51	under.med	Underbuild - Medium Non-Firm Market Prices	-	-	-	-	-	234
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	-	-	-	-	-	490
57	tran.uprate	Test of Transmission Plant Conversion	-	-	-	-	263	463
58	tran.bridger	Added Transmission - Bridger to OWC	-	-	-	13	312	556
59	tran.utah	Added Transmission - Utah to OWC	-	-	-	11	294	543
61	renewable	Renewables at 35% of Capital Cost	-	-	-	-	115	313
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	-	-	-	48	521	918
66	extend.loads	Extension of Loads & DSM to 2045	-	-	-	25	311	556
67	extend.all	Extension of All Modeling to 2045	-	-	-	54	535	916
71	low.adders	Low Environmental Adders	-	601	1,076	1,076	1,277	1,277
72	med.adders	Medium Environmental Adders	-	1,826	3,157	3,820	3,831	3,831
73	high.adders	High Environmental Adders	-	1,826	3,366	3,829	4,123	4,157

Gas Fired Base Load Resources Selected by Year (Case XX less Case 1)

Energy MWa

Case Number	Study Name	Study Title	Study Year 1999	2000	2001	2002	2003	2005
1	base.case	Base Case	-	-	-	-	-	-
4	no.summer	No Summer Season	-	-	-	(11)	(169)	(274)
5	turbine	No Turbine Upgrades	-	-	-	72	129	126
6	herm.mg	Without Hermiston	-	-	-	185	410	398
7	herm.hg	Med Load High Gas Without Hermiston	-	-	-	138	425	409
11	no.DSM	No DSM	-	-	-	90	287	350
12	dsm.20dec	20% Conservation Advantage	-	-	-	(11)	(65)	(87)
13	dsm.15dec	15% Conservation Advantage	-	-	-	(11)	(51)	(72)
14	dsm.15inc	15% Conservation Disadvantage	-	-	-	22	47	41
21	ml.mg.pd	Med Low Load - Med Gas	-	-	-	(11)	(291)	(543)
22	mh.mg.pd	Med High Load - Med Gas	-	205	290	561	1,019	1,133
31	m.lg.pd	Med Load - Low Gas	-	1	1	101	41	64
32	limited.500	Limited Gas (500 MW) at Med Esc	-	-	-	88	4	(10)
33	m.hg.pd	Med Load - High Gas	-	-	-	76	(2)	(18)
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	-	-	-	(11)	(32)	(55)
41	lumpy	Resource Lumpiness	-	-	-	50	(10)	(13)
42	nf.lower	25% Lower Non-Firm Market Prices	-	-	-	(11)	(62)	(141)
43	nf.higher	25% Higher Non-Firm Market Prices	-	132	250	323	197	4
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	200	200	200	189	(51)	(168)
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	229	233	233	221	24	1
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	228	237	279	325	246	19
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	400	400	400	389	109	(93)
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	444	444	444	454	174	22
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	444	444	444	454	279	71
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	-	-	-	(11)	(291)	(389)
51	under.med	Underbuild - Medium Non-Firm Market Prices	-	-	-	(11)	(291)	(308)
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	-	-	-	(11)	(291)	(53)
57	tran.uprate	Test of Transmission Plant Conversion	-	-	-	(11)	(28)	(80)
58	tran.bridger	Added Transmission - Bridger to OWC	-	-	-	2	21	14
59	tran.utah	Added Transmission - Utah to OWC	-	-	-	-	3	0
61	renewable	Renewables at 35% of Capital Cost	-	-	-	(11)	(176)	(229)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	-	-	-	37	230	375
66	extend.loads	Extension of Loads & DSM to 2045	-	-	-	14	20	13
67	extend.all	Extension of All Modeling to 2045	-	-	-	43	244	373
71	low.adders	Low Environmental Adders	-	601	1,076	1,065	986	734
72	med.adders	Medium Environmental Adders	-	1,826	3,157	3,808	3,540	3,288
73	high.adders	High Environmental Adders	-	1,826	3,366	3,817	3,832	3,615

DSM Selected by Year

Summer Cumulative MW

Case Number	Study Name	Study Title	Study Year 1996	1997	1998	1999	2000	2001	2002	2003	2005
1	base.case	Base Case	30.0	62.4	97.4	133.4	170.0	206.9	243.4	280.2	352.4
4	no.summer	No Summer Season	27.6	60.3	99.2	140.2	186.1	233.4	283.0	334.9	444.6
5	turbine	No Turbine Upgrades	30.7	65.3	100.9	137.3	174.2	211.4	248.3	285.5	358.3
6	herm.mg	Without Hermiston	30.8	65.4	101.0	137.4	174.6	211.9	248.9	286.3	359.4
7	herm.hg	Med Load High Gas Without Hermiston	32.8	67.9	104.0	145.8	188.5	231.0	273.6	316.2	400.0
11	no.DSM	No DSM									
12	dsm.20dec	20% Conservation Advantage	33.3	78.1	123.8	170.0	217.0	263.9	310.8	357.7	449.9
13	dsm.15dec	15% Conservation Advantage	33.3	68.4	109.8	156.1	202.8	249.9	296.7	343.7	435.9
14	dsm.15inc	15% Conservation Disadvantage	20.3	47.0	75.7	105.1	137.1	169.2	201.2	233.4	296.6
21	ml.mg.pd	Med Low Load - Med Gas	6.2	12.6	18.8	25.5	32.4	39.5	46.6	60.5	111.8
22	mh.mg.pd	Med High Load - Med Gas	41.3	91.0	141.6	192.7	244.9	297.2	349.3	401.8	505.1
31	m.lg.pd	Med Load - Low Gas	26.1	55.2	85.4	116.1	147.4	178.8	210.0	241.4	302.8
32	limited.500	Limited Gas (500 MW) at Med Esc	32.8	67.8	103.8	144.6	186.1	227.5	269.0	310.5	392.0
33	m.hg.pd	Med Load - High Gas	32.8	67.9	104.0	145.8	188.5	231.0	273.6	316.2	400.0
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	32.8	67.8	109.2	155.4	202.3	249.3	296.2	343.1	435.3
41	lumpy	Resource Lumpiness	32.8	67.5	104.0	141.1	178.9	216.8	254.6	292.4	366.8
42	nf.lower	25% Lower Non-Firm Market Prices	28.7	61.3	94.7	129.8	166.2	202.8	239.1	275.6	347.3
43	nf.higher	25% Higher Non-Firm Market Prices	29.9	63.8	99.4	135.4	172.1	209.0	245.6	282.4	354.8
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	27.2	58.8	92.2	127.4	163.8	200.4	236.7	273.3	344.9
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	28.8	61.2	95.9	131.9	168.5	205.4	242.0	278.7	351.0
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	29.9	62.5	97.3	133.2	169.7	206.2	242.8	279.4	351.3
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	26.1	56.6	89.1	122.8	158.5	195.1	231.4	268.0	339.8
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	27.8	60.2	93.6	128.8	165.4	202.2	238.9	275.6	347.9
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	28.3	60.6	94.0	129.3	165.8	202.3	238.9	275.5	347.5
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	30.7	63.2	98.8	134.6	171.3	208.0	244.6	281.3	353.3
51	under.med	Underbuild - Medium Non-Firm Market Prices	33.3	68.4	104.4	140.8	178.1	215.3	252.4	289.7	362.8
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	33.3	68.4	104.4	140.8	178.1	215.3	252.4	289.7	362.8
57	tran.uprate	Test of Transmission Plant Conversion	32.2	66.9	102.9	144.8	187.8	231.0	273.9	317.1	401.8
58	tran.bridger	Added Transmission - Bridger to OWC	29.7	62.0	97.4	133.4	170.0	206.8	243.4	280.2	352.5
59	tran.utah	Added Transmission - Utah to OWC	30.0	62.4	97.4	133.4	170.0	206.9	243.4	280.2	352.4
61	renewable	Renewables at 35% of Capital Cost	28.8	61.2	95.0	130.8	167.2	203.8	240.1	276.6	348.3
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	32.0	66.6	103.6	141.2	179.3	217.7	255.9	294.3	369.6
66	extend.loads	Extension of Loads & DSM to 2045	23.6	53.0	84.2	116.5	150.9	185.6	222.0	258.7	331.9
67	extend.all	Extension of All Modeling to 2045	30.0	62.4	97.2	132.6	169.2	206.4	243.2	280.5	372.7
71	low.adders	Low Environmental Adders	32.3	67.5	103.5	140.0	177.1	214.4	251.6	288.8	361.9
72	med.adders	Medium Environmental Adders	38.7	79.3	120.8	162.6	205.3	248.0	290.5	333.2	425.6
73	high.adders	High Environmental Adders	43.0	87.8	133.6	179.7	226.7	273.6	320.4	367.4	459.8

DSM Selected by Year (Case XX less Case 1)

Summer Cumulative MW

Case Number	Study Name	Study Title	1996	1997	1998	1999	2000	2001	2002	2003	2005
1	base.case	Base Case									
4	no.summer	No Summer Season	(2.4)	(2.1)	1.8	6.8	16.1	26.5	39.6	54.7	92.2
5	turbine	No Turbine Upgrades	0.7	2.9	3.5	3.9	4.2	4.5	4.9	5.3	5.9
6	herm.mg	Without Hermiston	0.8	3.0	3.6	4.0	4.6	5.0	5.5	6.1	7.0
7	herm.hg	Med Load High Gas Without Hermiston	2.8	5.5	6.6	12.4	18.5	24.1	30.2	36.0	47.6
11	no.DSM	No DSM	(30.0)	(62.4)	(97.4)	(133.4)	(170.0)	(206.9)	(243.4)	(280.2)	(352.4)
12	dsm.20dec	20% Conservation Advantage	3.3	15.7	26.4	36.6	47.0	57.0	67.4	77.5	97.5
13	dsm.15dec	15% Conservation Advantage	3.3	6.0	12.4	22.7	32.8	43.0	53.3	63.5	83.5
14	dsm.15inc	15% Conservation Disadvantage	(9.7)	(15.4)	(21.7)	(28.3)	(32.9)	(37.7)	(42.2)	(46.8)	(55.8)
21	ml.mg.pd	Med Low Load - Med Gas	(23.8)	(49.8)	(78.6)	(107.9)	(137.6)	(167.4)	(196.8)	(219.7)	(240.6)
22	mh.mg.pd	Med High Load - Med Gas	11.3	28.6	44.2	59.3	74.9	90.3	105.9	121.6	152.7
31	m.lg.pd	Med Load - Low Gas	(3.9)	(7.2)	(12.0)	(17.3)	(22.6)	(28.1)	(33.4)	(38.8)	(49.6)
32	limited.500	Limited Gas (500 MW) at Med Esc	2.8	5.4	6.4	11.2	16.1	20.6	25.6	30.3	39.6
33	m.hg.pd	Med Load - High Gas	2.8	5.5	6.6	12.4	18.5	24.1	30.2	36.0	47.6
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	2.8	5.4	11.8	22.0	32.3	42.4	52.8	62.9	82.9
41	lumpy	Resource Lumpiness	2.8	5.1	6.6	7.7	8.9	9.9	11.2	12.2	14.4
42	nf.lower	25% Lower Non-Firm Market Prices	(1.3)	(1.1)	(2.7)	(3.6)	(3.8)	(4.1)	(4.3)	(4.6)	(5.1)
43	nf.higher	25% Higher Non-Firm Market Prices	(0.1)	1.4	2.0	2.0	2.1	2.1	2.2	2.2	2.4
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	(2.8)	(3.6)	(5.2)	(6.0)	(6.2)	(6.5)	(6.7)	(6.9)	(7.5)
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	(1.2)	(1.2)	(1.5)	(1.5)	(1.5)	(1.5)	(1.4)	(1.5)	(1.4)
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	(0.1)	0.1	(0.1)	(0.2)	(0.3)	(0.7)	(0.6)	(0.8)	(1.1)
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	(3.9)	(5.8)	(8.3)	(10.6)	(11.5)	(11.8)	(12.0)	(12.2)	(12.6)
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	(2.2)	(2.2)	(3.8)	(4.6)	(4.6)	(4.7)	(4.5)	(4.6)	(4.5)
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	(1.7)	(1.8)	(3.4)	(4.1)	(4.2)	(4.6)	(4.5)	(4.7)	(4.9)
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	0.7	0.8	1.4	1.2	1.3	1.1	1.2	1.1	0.9
51	under.med	Underbuild - Medium Non-Firm Market Prices	3.3	6.0	7.0	7.4	8.1	8.4	9.0	9.5	10.4
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	3.3	6.0	7.0	7.4	8.1	8.4	9.0	9.5	10.4
57	tran.uprate	Test of Transmission Plant Conversion	2.2	4.5	5.5	11.4	17.8	24.1	30.5	36.9	49.4
58	tran.bridger	Added Transmission - Bridger to OWC	(0.3)	(0.4)				(0.1)	0.0	0.0	0.1
59	tran.utah	Added Transmission - Utah to OWC									
61	renewable	Renewables at 35% of Capital Cost	(1.2)	(1.2)	(2.4)	(2.6)	(2.8)	(3.1)	(3.3)	(3.6)	(4.1)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	2.0	4.2	6.2	7.8	9.3	10.8	12.5	14.1	17.2
66	extend.loads	Extension of Loads & DSM to 2045	(6.4)	(9.4)	(13.2)	(16.9)	(19.1)	(21.3)	(21.4)	(21.5)	(20.5)
67	extend.all	Extension of All Modeling to 2045			(0.2)	(0.8)	(0.8)	(0.5)	(0.2)	0.3	20.3
71	low.adders	Low Environmental Adders	2.3	5.1	6.1	6.6	7.1	7.5	8.2	8.6	9.5
72	med.adders	Medium Environmental Adders	8.7	16.9	23.4	29.2	35.3	41.1	47.1	53.0	73.2
73	high.adders	High Environmental Adders	13.0	25.4	36.2	46.3	56.7	66.7	77.0	87.2	107.4

DSM Selected by Year
Energy MWa

Case Number	Study Name	Study Title	Study Year 1996	1997	1998	1999	2000	2001	2002	2003	2005
1	base.case	Base Case	20.5	42.4	66.5	91.5	117.0	142.5	168.1	193.7	244.2
4	no.summer	No Summer Season	12.9	27.1	44.3	62.1	83.2	104.5	126.9	150.0	199.8
5	turbine	No Turbine Upgrades	20.8	45.0	69.7	95.1	121.0	146.9	172.8	198.8	250.0
6	herm.mg	Without Hermiston	20.9	45.1	69.9	95.4	121.4	147.6	173.6	199.8	251.2
7	herm.hg	Med Load High Gas Without Hermiston	23.0	47.6	72.8	101.0	129.5	158.2	186.9	215.7	272.4
11	no.DSM	No DSM									
12	dsm.20dec	20% Conservation Advantage	23.5	52.9	83.1	113.5	144.4	175.5	206.5	237.6	298.9
13	dsm.15dec	15% Conservation Advantage	23.4	48.0	75.9	106.2	137.0	167.9	198.8	229.8	290.9
14	dsm.15inc	15% Conservation Disadvantage	13.7	30.9	49.4	68.3	89.6	110.9	132.2	153.6	195.7
21	ml.mg.pd	Med Low Load - Med Gas	5.4	10.9	16.4	22.1	28.0	34.0	40.1	49.7	84.9
22	mh.mg.pd	Med High Load - Med Gas	29.4	63.1	97.6	132.5	168.0	203.7	239.3	275.1	345.7
31	m.lg.pd	Med Load - Low Gas	16.9	35.7	55.1	74.9	95.1	115.3	135.5	155.7	195.5
32	limited.500	Limited Gas (500 MW) at Med Esc	23.0	47.5	72.7	100.3	128.4	156.6	184.7	212.9	268.4
33	m.hg.pd	Med Load - High Gas	23.0	47.6	72.8	101.0	129.5	158.2	186.9	215.7	272.4
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	23.0	47.5	75.3	105.6	136.4	167.2	198.0	229.0	289.9
41	lumpy	Resource Lumpiness	23.0	47.1	72.5	98.4	124.7	151.1	177.4	203.9	255.8
42	nf.lower	25% Lower Non-Firm Market Prices	19.1	41.0	63.6	87.7	112.9	138.2	163.4	188.6	238.3
43	nf.higher	25% Higher Non-Firm Market Prices	20.5	44.0	68.8	93.9	119.5	145.2	170.8	196.5	247.0
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	17.6	38.7	61.3	85.4	110.6	135.9	161.1	186.3	236.0
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	19.4	41.3	65.2	90.2	115.7	141.3	166.8	192.4	242.9
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	20.5	42.7	66.7	91.7	117.1	142.6	168.0	193.6	243.8
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	16.9	37.1	58.8	81.6	106.2	131.4	156.6	181.9	231.5
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	18.6	40.5	63.0	87.3	112.7	138.3	163.8	189.5	240.0
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	19.2	41.2	63.8	88.1	113.5	139.0	164.5	190.0	240.2
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	20.8	42.8	67.5	92.4	117.8	143.2	168.5	194.0	243.9
51	under.med	Underbuild - Medium Non-Firm Market Prices	23.4	48.0	73.3	98.8	124.8	151.0	177.0	203.2	254.7
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	23.4	48.0	73.3	98.8	124.8	151.0	177.2	203.4	255.1
57	tran.uprate	Test of Transmission Plant Conversion	22.4	46.5	71.8	99.9	128.7	157.7	186.5	215.5	272.5
58	tran.bridger	Added Transmission - Bridger to OWC	20.2	42.1	66.6	91.6	117.1	142.6	168.2	193.8	244.3
59	tran.utah	Added Transmission - Utah to OWC	20.5	42.4	66.5	91.5	117.0	142.5	168.1	193.7	244.2
61	renewable	Renewables at 35% of Capital Cost	19.4	41.3	64.3	89.1	114.3	139.6	164.7	190.0	239.7
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	22.1	46.2	71.7	97.6	124.1	150.6	177.1	203.7	256.0
66	extend.loads	Extension of Loads & DSM to 2045	15.9	35.6	56.7	78.4	101.8	125.2	150.5	176.1	227.4
67	extend.all	Extension of All Modeling to 2045	20.4	42.4	66.3	90.7	116.2	142.1	167.9	194.0	254.7
71	low.adders	Low Environmental Adders	23.1	47.7	73.1	98.8	124.9	151.3	177.5	203.9	255.8
72	med.adders	Medium Environmental Adders	26.2	53.6	81.6	110.0	138.9	167.9	196.8	225.9	287.2
73	high.adders	High Environmental Adders	28.3	57.7	87.8	118.3	149.2	180.3	211.2	242.4	303.6

DSM Selected by Year (Case XX less Case 1)

Energy MWa

Case Number	Study Name	Study Title	Study Year								
			1996	1997	1998	1999	2000	2001	2002	2003	2005
1	base.case	Base Case									
4	no.summer	No Summer Season	(7.6)	(15.3)	(22.2)	(29.4)	(33.8)	(38.0)	(41.2)	(43.7)	(44.4)
5	turbine	No Turbine Upgrades	0.3	2.6	3.2	3.6	4.0	4.4	4.7	5.1	5.8
6	herm.mg	Without Hermiston	0.4	2.7	3.4	3.9	4.4	5.1	5.5	6.1	7.0
7	herm.hg	Med Load High Gas Without Hermiston	2.5	5.2	6.3	9.5	12.5	15.7	18.8	22.0	28.2
11	no.DSM	No DSM	(20.5)	(42.4)	(66.5)	(91.5)	(117.0)	(142.5)	(168.1)	(193.7)	(244.2)
12	dsm.20dec	20% Conservation Advantage	3.0	10.5	16.6	22.0	27.4	33.0	38.4	43.9	54.7
13	dsm.15dec	15% Conservation Advantage	2.9	5.6	9.4	14.7	20.0	25.4	30.7	36.1	46.7
14	dsm.15inc	15% Conservation Disadvantage	(6.8)	(11.5)	(17.1)	(23.2)	(27.4)	(31.6)	(35.9)	(40.1)	(48.5)
21	ml.mg.pd	Med Low Load - Med Gas	(15.1)	(31.5)	(50.1)	(69.4)	(89.0)	(108.5)	(128.0)	(144.0)	(159.3)
22	mh.mg.pd	Med High Load - Med Gas	8.9	20.7	31.1	41.0	51.0	61.2	71.2	81.4	101.5
31	m.lg.pd	Med Load - Low Gas	(3.6)	(6.7)	(11.4)	(16.6)	(21.9)	(27.2)	(32.6)	(38.0)	(48.7)
32	limited.500	Limited Gas (500 MW) at Med Esc	2.5	5.1	6.2	8.8	11.4	14.1	16.6	19.2	24.2
33	m.hg.pd	Med Load - High Gas	2.5	5.2	6.3	9.5	12.5	15.7	18.8	22.0	28.2
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	2.5	5.1	8.8	14.1	19.4	24.7	29.9	35.3	45.7
41	lumpy	Resource Lumpiness	2.5	4.7	6.0	6.9	7.7	8.6	9.3	10.2	11.6
42	nf.lower	25% Lower Non-Firm Market Prices	(1.4)	(1.4)	(2.9)	(3.8)	(4.1)	(4.3)	(4.7)	(5.1)	(5.9)
43	nf.higher	25% Higher Non-Firm Market Prices		1.6	2.3	2.4	2.5	2.7	2.7	2.8	2.8
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	(2.9)	(3.7)	(5.2)	(6.1)	(6.4)	(6.6)	(7.0)	(7.4)	(8.2)
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	(1.1)	(1.1)	(1.3)	(1.3)	(1.3)	(1.2)	(1.3)	(1.3)	(1.3)
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices		0.3	0.2	0.2	0.1	0.1	(0.1)	(0.1)	(0.4)
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	(3.6)	(5.3)	(7.7)	(9.9)	(10.8)	(11.1)	(11.5)	(11.8)	(12.7)
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	(1.9)	(1.9)	(3.5)	(4.2)	(4.3)	(4.2)	(4.3)	(4.2)	(4.2)
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	(1.3)	(1.2)	(2.7)	(3.4)	(3.5)	(3.5)	(3.6)	(3.7)	(4.0)
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	0.3	0.4	1.0	0.9	0.8	0.7	0.4	0.3	(0.3)
51	under.med	Underbuild - Medium Non-Firm Market Prices	2.9	5.6	6.8	7.3	7.8	8.5	8.9	9.5	10.5
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	2.9	5.6	6.8	7.3	7.8	8.5	9.1	9.7	10.9
57	tran.uprate	Test of Transmission Plant Conversion	1.9	4.1	5.3	8.4	11.7	15.2	18.4	21.8	28.3
58	tran.bridger	Added Transmission - Bridger to OWC	(0.3)	(0.3)	0.1	0.1	0.1	0.1	0.1	0.1	0.1
59	tran.utah	Added Transmission - Utah to OWC									
61	renewable	Renewables at 35% of Capital Cost	(1.1)	(1.1)	(2.2)	(2.4)	(2.7)	(2.9)	(3.4)	(3.7)	(4.5)
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	1.6	3.8	5.2	6.1	7.1	8.1	9.0	10.0	11.8
66	extend.loads	Extension of Loads & DSM to 2045	(4.6)	(6.8)	(9.8)	(13.1)	(15.2)	(17.3)	(17.6)	(17.6)	(16.8)
67	extend.all	Extension of All Modeling to 2045	(0.1)		(0.2)	(0.8)	(0.8)	(0.4)	(0.2)	0.3	10.5
71	low.adders	Low Environmental Adders	2.6	5.3	6.6	7.3	7.9	8.8	9.4	10.2	11.6
72	med.adders	Medium Environmental Adders	5.7	11.2	15.1	18.5	21.9	25.4	28.7	32.2	43.0
73	high.adders	High Environmental Adders	7.8	15.3	21.3	26.8	32.2	37.8	43.1	48.7	59.4

Net Non-Firm Energy used by the System

(Sales less Purchases) MWa

Case Number	Study Name	Study Title	Study Year									
			1996	1997	1998	1999	2000	2001	2002	2003	2005	Average
1	base.case	Base Case	408	713	752	724	660	617	532	742	921	674
4	no.summer	No Summer Season	401	699	738	703	635	586	476	552	644	604
5	turbine	No Turbine Upgrades	408	652	709	658	586	508	518	781	957	642
6	herm.mg	Without Hermiston	301	292	387	341	270	211	313	726	909	417
7	herm.hg	Med Load High Gas Without Hermiston	302	303	394	354	293	233	280	755	909	425
11	no.DSM	No DSM	389	677	714	664	581	486	491	850	1,020	652
12	dsm.20dec	20% Conservation Advantage	411	722	761	743	681	641	554	713	867	677
13	dsm.15dec	15% Conservation Advantage	411	718	757	736	676	637	547	720	874	675
14	dsm.15inc	15% Conservation Disadvantage	402	703	741	708	640	592	528	756	933	667
21	ml.mg.pd	Med Low Load - Med Gas	640	952	983	979	957	961	929	910	970	920
22	mh.mg.pd	Med High Load - Med Gas	153	396	410	303	408	389	531	1,004	1,092	521
31	m.lg.pd	Med Load - Low Gas	405	703	706	659	582	503	509	646	840	617
32	limited.500	Limited Gas (500 MW) at Med Esc	410	723	788	769	682	654	658	766	916	707
33	m.hg.pd	Med Load - High Gas	410	723	788	770	683	655	648	763	915	706
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	410	717	757	736	675	636	546	712	859	672
41	lumpy	Resource Lumpiness	410	717	755	729	665	623	604	739	935	686
42	nf.lower	25% Lower Non-Firm Market Prices	407	260	254	230	248	204	279	389	520	310
43	nf.higher	25% Higher Non-Firm Market Prices	408	763	855	813	856	914	914	989	991	834
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	405	259	253	350	434	404	422	394	490	379
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	407	712	751	914	868	816	729	754	922	764
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	408	762	853	964	940	929	912	1,010	994	864
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	405	258	250	440	578	556	547	506	566	456
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	406	711	750	1,020	969	964	909	836	913	831
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	407	761	851	1,044	1,003	1,012	961	1,009	1,011	895
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	408	261	257	234	253	208	283	214	297	268
51	under.med	Underbuild - Medium Non-Firm Market Prices	411	718	755	729	665	623	525	453	646	614
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	411	766	858	817	744	681	585	683	1,009	728
57	tran.uprate	Test of Transmission Plant Conversion	410	716	755	731	669	629	534	733	887	674
58	tran.bridger	Added Transmission - Bridger to OWC	449	762	806	777	707	659	569	804	954	721
59	tran.utah	Added Transmission - Utah to OWC	413	724	768	741	673	623	531	744	921	682
61	renewable	Renewables at 35% of Capital Cost	407	712	831	900	833	782	696	752	907	758
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	404	744	766	674	589	528	488	839	971	667
66	extend.loads	Extension of Loads & DSM to 2045	404	707	746	715	648	604	535	747	926	670
67	extend.all	Extension of All Modeling to 2045	402	741	762	668	584	521	488	846	970	665
71	low.adders	Low Environmental Adders	(721)	(721)	(721)	(721)	(721)	(721)	(624)	(235)	(209)	(599)
72	med.adders	Medium Environmental Adders	(721)	(721)	(721)	(721)	(721)	(664)	(446)	(471)	(448)	(626)
73	high.adders	High Environmental Adders	(721)	(721)	(721)	(721)	(721)	(489)	(347)	(196)	(215)	(539)

Net Non-Firm Energy used by the System (Case XX less Case 1)

(Sales less Purchases) MWa

Case Number	Study Name	Study Title	Study Year 1996	1997	1998	1999	2000	2001	2002	2003	2005	Average
1	base.case	Base Case	-	-	-	-	-	-	-	-	-	-
4	no.summer	No Summer Season	(7)	(14)	(13)	(21)	(25)	(31)	(56)	(190)	(277)	(70)
5	turbine	No Turbine Upgrades	0	(61)	(43)	(66)	(74)	(109)	(14)	40	36	(32)
6	herm.mg	Without Hermiston	(107)	(420)	(365)	(383)	(390)	(406)	(219)	(16)	(12)	(258)
7	herm.hg	Med Load High Gas Without Hermiston	(106)	(409)	(358)	(370)	(366)	(384)	(253)	14	(12)	(249)
11	no.DSM	No DSM	(19)	(36)	(38)	(61)	(79)	(131)	(41)	109	98	(22)
12	dsm.20dec	20% Conservation Advantage	3	9	9	19	21	24	22	(28)	(55)	3
13	dsm.15dec	15% Conservation Advantage	3	5	5	12	16	20	14	(22)	(48)	1
14	dsm.15inc	15% Conservation Disadvantage	(6)	(10)	(11)	(16)	(20)	(25)	(4)	14	12	(7)
21	ml.mg.pd	Med Low Load - Med Gas	232	239	232	255	297	344	397	168	49	246
22	mh.mg.pd	Med High Load - Med Gas	(255)	(317)	(342)	(421)	(252)	(228)	(1)	262	171	(154)
31	m.lg.pd	Med Load - Low Gas	(3)	(10)	(46)	(65)	(78)	(114)	(23)	(96)	(81)	(57)
32	limited.500	Limited Gas (500 MW) at Med Esc	2	11	36	45	23	37	125	25	(6)	33
33	m.hg.pd	Med Load - High Gas	2	11	36	46	23	38	116	21	(7)	32
34	hg.nonf	High Gas - with Medium Non-firm Market Prices	2	4	5	12	15	20	14	(29)	(62)	(2)
41	lumpy	Resource Lumpiness	2	4	3	5	6	6	72	(2)	13	12
42	nf.lower	25% Lower Non-Firm Market Prices	(1)	(453)	(498)	(494)	(411)	(413)	(254)	(353)	(401)	(364)
43	nf.higher	25% Higher Non-Firm Market Prices	0	50	103	89	196	297	382	247	69	159
44	over.250.low	250 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	(3)	(454)	(499)	(374)	(226)	(213)	(111)	(347)	(431)	(295)
45	over.250.med	250 MW Plant in 1999 - Medium Non-Firm Market Prices	(1)	(1)	(1)	190	208	200	196	13	0	89
46	over.250.high	250 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	0	49	101	240	281	312	380	268	73	189
47	over.500.low	500 MW Plant in 1999 - 25% Lower Non-Firm Market Prices	(3)	(455)	(501)	(285)	(82)	(61)	14	(235)	(355)	(218)
48	over.500.med	500 MW Plant in 1999 - Medium Non-Firm Market Prices	(2)	(2)	(2)	296	310	347	377	94	(8)	157
49	over.500.high	500 MW Plant in 1999 - 25% Higher Non-Firm Market Prices	(1)	48	99	320	343	395	429	267	90	221
50	under.low	Underbuild - 25% Lower Non-Firm Market Prices	0	(452)	(495)	(490)	(407)	(409)	(249)	(528)	(624)	(406)
51	under.med	Underbuild - Medium Non-Firm Market Prices	3	5	3	5	6	6	(7)	(288)	(275)	(60)
52	under.high	Underbuild - 25% Higher Non-Firm Market Prices	3	53	106	93	84	64	53	(59)	87	54
57	tran.uprate	Test of Transmission Plant Conversion	2	4	3	7	10	12	2	(8)	(34)	(0)
58	tran.bridger	Added Transmission - Bridger to OWC	41	49	54	53	47	42	37	62	33	46
59	tran.utah	Added Transmission - Utah to OWC	5	12	16	17	14	6	(1)	3	-	8
61	renewable	Renewables at 35% of Capital Cost	(1)	(1)	80	176	173	165	164	10	(14)	83
65	extend.firm	Extension of all Existing Firm Wholesale Contracts	(4)	31	14	(51)	(71)	(89)	(45)	98	50	(7)
66	extend.loads	Extension of Loads & DSM to 2045	(4)	(6)	(6)	(9)	(12)	(13)	2	5	5	(4)
67	extend.all	Extension of All Modeling to 2045	(6)	28	10	(56)	(76)	(96)	(45)	105	49	(10)
71	low.adders	Low Environmental Adders	(1,129)	(1,434)	(1,473)	(1,445)	(1,381)	(1,338)	(1,156)	(977)	(1,130)	(1,274)
72	med.adders	Medium Environmental Adders	(1,129)	(1,434)	(1,473)	(1,445)	(1,381)	(1,281)	(978)	(1,212)	(1,369)	(1,300)
73	high.adders	High Environmental Adders	(1,129)	(1,434)	(1,473)	(1,445)	(1,381)	(1,106)	(879)	(938)	(1,136)	(1,213)

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Chapter 4:

Comments on Draft Report

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October 16, 1995

Nancy Esteb, Manager
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Dear ~~Ms.~~ Nancy Esteb:

Thank you for the opportunity to comment on PacifiCorp's draft RAMPP-4 report. These comments are late, but I hope they can still help you in revising the report.

We appreciate the hard work that is reflected in the draft document. Overall, the draft action plan, including the level of demand-side resource acquisitions, seems reasonable. We offer the following specific comments.

Wholesale Power Markets: In view of the importance of wholesale non-firm power market in influencing decisions of the company, the document should be more specific regarding market assumptions. A price estimate (16-19 mills, p.26) is provided, but little additional information. What is the estimated size of the market and its expected duration? What price behavior over time is assumed? Page 26 speaks of prices leveling across seasons and geographic areas as sales and transmission access open, yet complete leveling seems unlikely in view of the continuing regional seasonality of load and the possibility of distance-based transmission rates.

Supply-side Portfolio Depreciation Lives (Table 3-18): Fifty years is used as the depreciation life for all supply side resources. While this may be reasonable for hydropower and possibly geothermal, fifty years appears to be unreasonably long for most other technologies. While there are examples of fifty-year old powerplants, plants this age would require major capital infusions to continue operating in the mode originally intended. Twenty to thirty years seems a more realistic depreciation life for thermal resources, cogeneration and wind.

Thermal Plant Efficiency Improvements: The draft document, presentations to the RAG and recent actions by the company all indicate a continuing interest in maintaining and increasing the efficiency of most of the company's thermal resources. This is important for both economic and environmental reasons. But the company's plans for Centralia remain mysterious. How will Phase II sulfur dioxide control requirements be met? What is the situation regarding nitrogen oxide emissions and alleged impact on Mt. Rainier National Park? To what extent will rail haul coal be substituted for local coal? What is the potential for efficiency improvements or repowering of the plant? Insights regarding these issues are important because of the size, age, ownership and environmental impact potential of the project.

Hydro Relicensing and Efficiency Improvements: While the draft RAAMP includes a detailed assessment of thermal resource efficiency improvement potential, virtually no information or analysis of hydropower efficiency improvement potential is provided. While hydropower comprises a relatively small proportion of company resources, it would be useful to provide additional information and analysis of possible hydro efficiency improvements and relicensing issues.

Regional Solar Monitoring Network: PacifiCorp is to be congratulated for its charter participation in the Northwest Regional Solar Monitoring Network. The final RAAMP-4 should reaffirm the company's intent to continue support for this project.

OSU Wind Research Cooperative: PacifiCorp is also to be commended for its continuing support of the Oregon State University Wind Research Cooperative. The final RAAMP-4 should reaffirm the company's continuing support for this project. The company may wish to engage the Wind Research Cooperative in designing a research agenda for its wind demonstration projects (see below).

Wind Demonstration Projects: The Council is pleased to note the level of regional utility support given to wind demonstration projects. PacifiCorp is a leader in this effort. Because these projects will be among the first of their type to be developed in the Northwest, we urge the company to ensure that research programs are implemented to maximize the value of the Foote Creek Rim and Columbia Hills projects. Topics of value to future development of wind power in the Northwest include documentation of licensing experience; environmental and physical development issues and their resolution; seasonality, shear, turbulence , interannual variation and other wind resource characteristics; electrical integration experience; and project performance and operation and maintenance experience. The company may also wish to consider the installation of a long-term wind resource monitoring station at Foote Creek Rim, in conjunction with the Bonneville long-term wind resource monitoring network. Though certain resource, cost and performance information is of proprietary value to the project developer or the company, a primary justification for the premium needed by these projects is their demonstration value, a value that can be fully secured only through well-conceived research program.

Global Climate Change: The company's demonstration carbon offset projects are prudent and commendable and it is important that these efforts continue. However, in view of increasing evidence of an anthropogenic contribution to global warming, the conclusion that control of greenhouse gas production is unlikely for the next ten years (Chap. 1, p.14) appears optimistic. Because the need to control carbon dioxide production could significantly affect the cost of the company's fossil fuel resources and the cost of purchases derived from fossil fuel plants it would be desirable to include an action to monitor global climate change research findings. It would also be prudent to revise the proposed global warming benchmark to turn not upon passage of a federal tax or controls, but upon scientific or international governmental agreements that are likely to precede congressional action resulting in taxes or controls.

Photovoltaic Applications: Though large-scale photovoltaics are unlikely to be cost-effective for many years, numerous small-scale "niche" applications are cost-effective at present. The company, perhaps in alliance with other Oregon utilities, should consider expanding its photovoltaic program to identify and assist in the development of cost-effective niche applications. Ensuring that all cost-effective photovoltaic applications are developed will promote better understanding of the technology, expand the market for photovoltaic devices and perhaps lead to new and innovative applications.

Special Biomass Projects: There are a diversity of biomass residue materials that could be used for power generation. These include clean municipal solid waste fractions, animal manure, forest thinning residues, agricultural and food processing wastes, landfill gas recovery and wastewater treatment plant gas recovery. Another promising source of biomass power is the upgrading of chemical recovery boilers at pulp mills. While often not competitive solely on the basis of electricity production costs, these projects often bring important non-power benefits. While we would not expect the company to pay a significant premium for the power output of these facilities, the company could ensure that a market, at competitive prices, is available for these projects (the timing of which is usually driven by non-power concerns), and offer wheeling services at competitive rates, credit for distributed generation benefits and other measures to facilitate the development of these projects.

Lost Opportunity Conservation Markets: (Chapter 3, p 14) The definition of lost-opportunity markets should include new and expanding industrial facilities. This is approximately identified as new growth in the forecast. In addition, any process or facility changes going on in an existing industrial plant represent a window of opportunity to pursue efficiency that is on the customer's terms. We would also encourage you to count these as lost-opportunity resources. This is an important perspective in relation to both the avoided cost of these resources and in relation to how industrial customers are approached.

DSM description in Chapter 6 Action Plan: (Chapter 6, p 17) The casual reader will not know that there is an entire chapter following this one on DSM actions. In addition, the paragraphs on this page do not capture the items in Chapter 7 or vice versa. If page 17 is taken as the over-riding goal for DSM actions, the first sentence should be revised to incorporate a balance between least cost planning and the competitive utility environment. After all, the level you did select was least cost, considering cost, financial and price impacts.

Technology Transformation: (Chapter 7, p 23) The company should make a stronger commitment across all sectors and end-uses to work with multiple parties (including, but not limited to those you mention i.e. City of Portland, CEE, and home manufacturers) to bring energy efficient products to markets. PacifiCorp will be an important player in multiple projects that are likely to be initiated during the action plan period, and a clear indication should be given in the action plan that you will be a willing partner in the investigation of market transformation efforts and follow through if the investigations prove fruitful.

General, Chapters 4 and 5: For simplicity and brevity, please incorporate the Chapter 4 descriptions of the model runs with the results in Chapter 5. This should avoid duplication and make it easier for the reader. Also, please include table 5-16 at the front of the chapter, with descriptions of the effect on net present value. This is of interest to many readers, and it will simplify their thought process if financial results (including mills/kWh), emissions and net present value are presented at the same time.

Relationship of RAMPP-3 and RAMPP-4 Action Plans: It is not clear in the document if the RAMPP-4 actions completely supercede or simply add to the RAMPP-3 action plan. It appears that PacifiCorp is continuting a number of items in the RAMPP-3 plan, but has not mentioned them in RAMPP-4. Please make sure to include at least the following on-going items in the RAMPP-4 action items.

- Continue small-scale carbon offset projects (RAAMP-3, #9)
- Continue evaluation of cost-effectiveness and performance of wind projects (RAAMP-3, #2b)
- Continue to participate in Solar II demonstration project (RAAMP-3, 2e)
- Continue to monitor performance of solar PV projects, publish results (RAAMP-3, 2g) (also part of RAAMP-3, 2i)
- Continue participation in Northwest Regional Solar Radiation Data Monitoring Project (does not appear in RAAMP-3)
- Continue to support OSU Wind Research Cooperative (does not appear in RAAMP-3)

Social and Environmental Objectives: We agree that it will be increasingly difficult to continue to achieve power-related social and environmental objectives using the approaches that have been employed in the past. We also agree that approaches that unequally burden players in the energy market are undesirable and bound to eventual failure. An important aspect of rethinking the role of the IRP in the changing industry environment is assessing which societal and environmental objectives warrant continued special effort and how these objectives might be achieved by the industry of the future. PacifiCorp has provided valuable contributions to this discussion in the recent past. We look to the company to continue its contributions to the regional dialog regarding this issue.

Sincerely,

Margie

Margaret Gardner
Senior Conservation Analyst

Jeff King
Senior Resource Analyst

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Oregon
PUBLIC
UTILITY
COMMISSION

October 6, 1995

NANCY ESTEB
MANAGER, INTEGRATED RESOURCE PLANNING
PACIFICORP
825 NE MULTNOMAH
PORTLAND OR 97232

RE: Comments on PacifiCorp's RAMPP4 Draft Integrated Resource Plan

Commission staff appreciates the opportunity to review and provide comments on PacifiCorp's RAMPP4 Draft Integrated Resource Plan. Our comments and questions on the draft plan are attached for your consideration in finalized the RAMPP4 report. If you have questions or need clarification on our comments, please call me.

I appreciate your hard work in preparing this draft and look forward to working with you and your staff in the future.

Sincerely,

John C. Britton
Public Utility Analyst
Energy Division
(503) 373-7905
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c. Mike Kane
Bill Warren
Lee Sparling
Bill McNamee
Judy Johnson
Lynn Plamondon

INTEGRATED RESOURCE PLANNING
OCT 10 1995

John A. Kitzhaber
Governor

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Comments on PacifiCorp's RAMPP4 Least Cost Plan Draft
Public Utility Commission of Oregon

October 6, 1995

General Comments

1. Staff agrees with Ken Powell's comment at the 9/22/95 meeting that the rationale for the RAMPP4 action plan follows the model results and is an improvement over RAMPP3.

2. Staff recognizes the company's significant effort in producing RAMPP4 and feels that the company did a good job accommodated the concerns of the technical advisory group. Staff appreciates your hard work.

Chapter 1

1. This chapter provides a good summary and introduction to the rest of the document. Please add a section after "PacifiCorp's Perception of the Future" (pp. 2 - 14) that briefly discusses the implications for resource planning based upon this perception. This new section could incorporate several important themes developed later in the report:

   a. In an uncertain environment, flexibility is important. Actions that add to the possible resource choices the company can make in the future should be pursued.

   b. The company's analysis attempted to identify which specific factors influenced resource selection and prices most significantly. These factors were load growth, gas prices, non-firm wholesale prices, renewable resource costs, and federal governmental environmental regulation.

   c. If these factors vary materially from the forecast level in RAMPP4, the company will need to re-examine the action plan.

Move the section entitled "Public Advisory Process" to the end of Chapter 1.

2. Page 6: Portland General Electric will be providing power to Canby. However, PGE is buying all of the power to serve Canby from BPA, through a contract that is tied specifically to the PGE-Canby deal. This is not an example of robust competition, but rather an example of competition bumping up against BPA's market power.

3. Page 11, second paragraph, first sentence under "Wholesale Market as a Resource": Add "can fluctuate significantly" after "spot prices." Delete "even though" and everything after "spot prices."

Chapter 2

1. Page 3, Response to OPUC RAMPP3 comment #3: The company's response to this issue is not adequate. However, you may have the data to expand upon the response. Staff's RAMPP3 comment is asking about the prudency of overbuilding or acquiring resources before they are needed for retail load. The current WSCC market has surplus supplies, prices have dropped, margins are thin, and FERC is attempting to make the market more competitive by opening up transmission. In this environment, it may be impossible to "sell any surplus on the wholesale market." The company's response needs to be expanded and supported--perhaps by referencing the overbuild/underbuild scenario.

2. Page 15, end of the first paragraph: Staff understands the company's concern about proprietary information. Do you mean that you do not want to disclose certain information, or are you suggesting the information be disclosed, but remain confidential under a protective order. Please clarify.

3. Page 15, second paragraph: regarding the need for more flexibility in IRP action plans. Along these lines, the company should develop an ability to do more option analysis (i.e. to assess the value of certain actions that may provide a greater range of resource choices in the future). For example, renewable development, DSM pilots, or site acquisition and certification for supply-side resources all provide the company with future choices or options that may have inherent value under certain market conditions. Staff is not sure how to do this kind of analysis, but under uncertain futures, strategies that provide more choices (but may cost more initially), may be better than those that limit future choices (but cost less now). The issue is how much more cost is prudent?

Chapter 4

Page 10, Underbuilding: The main issue this plan does not address adequately is the issue of relying upon the short-term non-firm market for resources, instead of building or buying other resources. These underbuild scenarios are not what staff had assumed they were. Staff assumed that the model was being forced to purchase short-term non-firm power (at the market's marginal cost) instead of building new resources (at fully embedded cost). The decision facing many western utilities is not, build vs. buy; it's whether to buy short term, intermediate term, or build or buy long term resources. Admittedly, the model may simply produce a lower cost when the short-term non-firm market is used to meet resource needs--without also showing the accompanying risks. The underbuild scenarios in RAMPP4 apparently modeled the tradeoff between building a long term resource and buying a resource that was priced higher than the embedded cost of the long term resource. (Chapter 5, pp. 17 - 18) If this is true, the results of these model runs are not surprising. At a minimum, the company needs to clarify what these underbuild studies represent, and what they do not represent.

Clearly, regulators are concerned about building or buying any asset, when the market is already highly overbuilt, market prices are falling, margins are thin, and the market becoming more fluid. Regulators are further concerned because PacifiCorp has seemed to employ a build and buy asset strategy while the WSCC market has a 25% - 30% surplus. The company writes in the draft plan: "For example, if the company has an opportunity to acquire a cost-effective resource sooner than needed to meet retail loads, it can do so and sell any surplus on the wholesale market." (Chapter 2, page 3) The problem is that PacifiCorp may not be able to sell all of its own surplus on the wholesale market at a price equal to or higher than its variable cost. The prudent action for most utilities now seems to be wait and watch the market carefully for market surplus reductions that might trigger an adjustment to resource plans. All this goes along with the comment above about chapter 2, page 3. This is also an issue that needs to be addressed in RAMPP5.

Chapter 5

1. Page 28: The section entitled "Findings" is very important and needs to be highlighted. Perhaps pieces of this could be used to fill out the additional section staff recommended you add to chapter 1.

2. Page 29, Gas Prices: This section was difficult to understand and could use some clarification. Are you saying that non-firm sales revenues (that PacifiCorp credits to rates) offset higher gas fuel costs when gas prices rise?

Chapter 6

1. Page 9, discussion about the APS SCCT: In chapter 3, page 27, the company says that the WSCC has "a very high capacity surplus." Given this, is there a way to avoid the APS SCCT for a longer term? If so, how long? Please expand your discussion.

2. Page 12, discussion about data for residential customer power use: When will these data be available? How will it be used?

3. Page 14, discussion on carbon offsets: Becky Wilson's comments at the 9/22/95 meeting were useful--please add some comparison between total system emissions and levels of CO_2 these programs mitigate.

4. Page 17, RAMPP4 Action Plan: Ken Powell's comment at the 9/22/95 meeting was good--adding a specific goal and deadline to appropriate (perhaps not all) action items would tighten up the plan considerably.

5. Page 19, section a): Replace second sentence with, "Once these projects are operating, evaluate performance and actual cost-effectiveness."

6. Pages 20 - 33: This is an extremely useful section. Is there a way to highlight it more?

7. Page 20, last paragraph: "Postponing resource decisions is likely to lead to lower-cost opportunities." Again, the underbuild scenarios were intended to show the effects of delaying resource decisions. As these scenarios were modeled, they showed higher overall costs by delaying resource acquisition compared to the base case. Could you support the statement with an example from the model runs?

8. Page 29, top paragraph: "With gas-fired resources priced below 30 mills/kWh, the company does not feel renewable resources are a cost-effective choice." The Commission has stated, however, that it believes renewables offer the potential benefits of risk management through resource diversity and low environmental impacts (See Order 94-727). Does PacifiCorp consider a gas-fired resource cost of 30 mills/kWh a threshold price for whether or not renewables are viable alternatives? The Commission strongly supports continued renewable development and has indicated a willingness to allow cost recovery of renewable resource acquisition costs which exceed the utility's avoided cost.

9. Page 30, Improving the RAMPP Process: Comments on Chapter 3, mentioned option analysis. Would you add an item to the action plan which would have the company assess the value of doing resource option analysis?

10. Pages 32 - 33: This section is important and , but should be expanded. How were the thresholds at the bottom of the page established? Do the thresholds drive prices unacceptably high or create dangerous resource deficits? If so, what prices are "unacceptably high" or what resource deficits are "dangerous"? In addition, briefly describe what actions might be taken if one of the factors exceeds these benchmark levels. If load growth exceeds 2.5% or the federal government passes an emissions tax, for example, what steps would PacifiCorp take?

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October 6, 1995

INTEGRATED RESOURCE PLANNING

OCT 11 1995

Oregon

DEPARTMENT O[F]

ENERGY

Nancy Esteb, Manager
Integrated Resource Planning
PacifiCorp
920 SW 6th Ave.
Porland, OR 97204

Dear Nancy:

The Oregon Department of Energy (ODOE) appreciates the hard work the staff of PacifiCorp devoted to the draft RAMPP 4 report. The draft plan seems analytically sound and is well written. Overall, the action plan seems reasonable. The negotiations over the level of demand-side resources in the action plan reached a reasonable settlement. ODOE supports acquiring the 19 average MW from the wind projects at Columbia Hills, Washington and Foot Creek, Wyoming.

Oregon PUC acknowledgement confers a conclusive presumption of need in Oregon siting process before the Oregon Energy Facility Siting Council (EFSC). It is important to be clear on the meaning of the RAMPP 4 action plan. RAMP 4 concludes:

> *... the action plan does not include a specific amount of summer peaking purchase or acquisition.* (Page 6-25 3rd paragraph); and
>
> *... the action plan includes no specific amounts of gas-fired baseload resources.* (Page 6-27 2nd paragraph).

ODOE understands this to mean that the plan does not call for siting or acquisition of new generation to meet summer peaking or baseload needs. ODOE supports these conclusions.

However, while RAMP 4 is in effect, conditions may change. PacifiCorp may conclude it needs to site a plant in Oregon to serve retail loads. If so, it could submit an amended plan as part of an EFSC site certificate application. Alternatively, it might want to submit an amendment to its RAMP 4 plan to the Oregon PUC for acknowledgement. This could occur concurrently with the EFSC application. ODOE supports this as a optional path for PacifiCorp to demonstrate need. If PacifiCorp wishes to retain this option, the RAMP 4 final report should discuss how the PUC process might work.

Given the context in 1994, when RAMPP 4 was begun, the overall analysis is appropriate. However, as the plan notes in Chapters 1 and 2, conditions are changing rapidly. ODOE does not believe this type of analysis will be adequate for RAMPP 5. Wholesale decisions seem to dominate decisions at PacifiCorp, but the RAMPP analysis focuses on needs of the retail business. For example, the timing of the contract with the Hermiston Generating Plant was apparently driven by estimates of its profitability in the wholesale market rather than retail needs.

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RAMPP 5 should explicitly examine the distribution of risk between the wholesale and retail parts of the business. As the plan notes, one possible future is a financial separation of the distribution, transmission and generation functions of PacifiCorp. Yet, the major function of least-cost planning is to provide a record for future retail rate case decisions. PacifiCorp and its ratepayers need a clear understanding of how the risks and rewards of the wholesale business will be shared. This context is essential for planning.

RAMP 4 recognizes that short term and long term purchases and building resources are competing alternatives, yet provides no analysis of their relative risks and benefits. West-wide transmission questions loom larger as PacifiCorp begins to rely more on purchases. RAMP 4 does not examine whether transmission capacity will be adequate for purchases. The long lead time for adding transmission capacity indicates that purchase decisions cannot wait until the last minute, as implied by RAMPP 4. Analyses of future wholesale market prices, including transmission and ancillary service prices, also seems essential for planning the retail and wholesale businesses.

ODOE believes the discussions on the context for RAMPP 5 should begin soon, even before RAMP 4 is acknowledged. RAMPP 5 may require new models of the west-wide power and transmission markets. Developing or acquiring these tools may take considerable time.

Sincerely,

Phil

Phil Carver
Senior Policy Analyst
Policy & Planning Division
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p&p pc puc pp&l rampp4.w51

INTEGRATED RESOURCE PLANNING

OCT 6 1995

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October 2, 1995

Ms. Nancy Esteb
Manager, IRP
PacifiCorp
825 NE Multnomah
Portland, OR 97232

Subject: Comments on Draft RAMPP-4

Dear Nancy:

Thank you for the opportunity to comment on PacifiCorp's draft integrated resource plan, RAMPP-4. As an overall comment, I think PacifiCorp has once again done an outstanding job of analysis, presentation, and public process. I also think this RAMPP is a major improvement over RAMPP-3, even though it was not as comprehensive an update as RAMPP-3.

As you know, I was only able to attend a few RAMPP Advisory Group (RAG) meetings during the development of this RAMPP. However, I avidly read the minutes and material that were developed for the RAG meetings and have found them immensely useful. If nothing else, PacifiCorp's analysis and information sharing activities provide a benefit to all of us at the Washington State Energy Office (WSEO).

The following are a few comments on the draft report. I articulated many of these at the last RAG meeting, but wanted to memorialize and clarify them in writing here.

Chapter 2, page 1

In the list of requirements for integrated resource plans, the company omitted Washington's requirement that the plan be "lowest cost to the utility and its ratepayers." Regardless how the term "lowest cost" is interpreted, I think most would agree lowest cost is the most important element of IRP (see, for example, the definition in EPACT) and its omission from this list is curious. Likewise, the characterization that the plan must only be "credible," rather than least cost, appears to understate the requirement. The Washington Utilities and Transportation Commission (WUTC) addressed this issue in detail in its acknowledgment letter for RAMPP-3 (see, for example, discussion on page 7 of the acknowledgment letter). "Lowest cost" need not mean only "lowest revenue requirements." If there are other cost factors such as risk, environmental costs, price elasticity concerns, etc., that need to be considered, they should be articulated in the plan and shown to be elements of a least cost plan.

Chapter 2, pages 3 and 7

On page 3, the company states wholesale transactions are limited to marketing excess capacity that becomes available due to the early acquisition of "lumpy" resources. The strategy is to market these surplus resources in order to reduce total system costs. However, on page 7 (response to item 5), the company appears to state it does not have the capability of analyzing the extent to which lumpiness affects system costs. If the latter is true, how can the company be assured that it is preferable to go long and market excess capacity, rather than going short and purchasing capacity and energy on the wholesale market? I note again that this was a major concern of the Washington Commission in its acknowledgment letter for RAMPP-3 (pages 5-6).

Chapter 2, pages 10 and 14

As noted by others at the RAG meeting, the company appears to focus heavily on price rather than revenue impacts. The response to item 5 on this page is an example. In response to a query regarding the impact of growth, the company states that load growth does not lead to "higher customer *prices*." Yet growth does lead to higher costs, which would appear on the face of it to be inconsistent with least *cost* planning. On the other hand, I agree with the statement on page 14 that the definition of "least cost" should "*incorporate* customers' price concerns" as one element of a comprehensive analysis of cost.

Chapter 3, page 13

Regarding the integration services contract with Clark County PUD, please explain why a peaking capacity and spinning reserve agreement has little effect on PacifiCorp's need for new resources and was not modeled. I would have thought this should be modeled as a peak load demand. As a more general matter, could you discuss somewhere how unbundled wholesale transactions will be modeled in future RAMPPs? I understand from the company's comments to Federal Energy Regulatory Commission (FERC) and other public statements that the company would like to be a major player in the unbundled services market and would like to have some comfort that the company has analyzed each such transaction to ensure it will not adversely affect retail service obligations.

Chapter 3, page 14

A confusing statement is on the top of this page. The company notes demand side management (DSM) can reduce lower operating costs and maintenance costs, and notes that these non-energy benefits "do not in fact reduce the cost of DSM for the utility." However, increased amenities *could* persuade the customer to pick up a greater share of the total cost of the program.

Therefore, although the energy savings remain the same, the relative value of the program to participants versus utilities shifts as non-energy amenities increase, and presumably the measure becomes more valuable to the participant. What assumptions does the company make concerning utility versus participant funding of DSM in its revenue requirements and price models?

Chapter 5, pages 29 and 30

The sections captioned "gas prices" and "overbuilding" conclude that the current connection between gas prices and nonfirm prices essentially holds the company's retail customers harmless from the risks of wholesale business. The final sentence of the "gas prices" section notes, for example: "*As long as* the company is successful in the wholesale market . . . customers should not suffer higher electricity prices from higher gas prices", (emphasis added). What does this imply about risks the company is potentially exposing to its customers? Is the company essentially allocating the risk of this business to its retail customers by its strategy of going long and marketing excess, rather than staying short and purchasing on the short-term nonfirm market?

Chapter 6, page 1

The discussion of IRP cycles, in my opinion, confuses two distinct but interrelated elements of IRP. The first, and most important, element is the company's *continuing* obligation to plan for and acquire resources consistently with least cost and sound analytical methodology. The second, less important element is the requirement that the company describe its past and current methodologies in a written document, also confusingly called an integrated resource plan. It is -- or should be -- incorrect to state that "IRP currently occurs in a two-year cycle." What *may* occur in a two-year cycle is a revisiting of methodological approaches, and perhaps some assumptions. Even the latter should occur more frequently than on a two-year cycle. This discussion should, therefore, be recast to focus on the fact -- true in 1985 as well as in 1995 -- that IRPs are not and should not be used to justify the acquisition of specific resources that are more than a few months away.

Chapter 6, page 6; Chapter 7, page 17

Has the company analyzed the potential for either water heater load control or irrigation load control in the Yakima area?

Chapter 6, page 20

I would like to suggest that the last item under 9, IRP, be modified to read, "Work with regulatory agencies . . . to make the process more value to utilities *and customers* operating in a competitive marketplace." If the IRP can show the company is the best retail competitive option on a price basis, it should. The IRP should also permit the customer to analyze and compare non cost features such as reliability and service.

Again, thank you for this opportunity to comment on your draft. I look forward to seeing the final product, as well as participating in future RAGs.

Sincerely,

Deb Ross

Deborah J. Ross
Senior Energy Policy Specialist

DJR/seb
D-L4-78

PS: I would appreciate getting copies of others' comments as well. Thanks.

LAND AND WATER FUND

Legal Aid For The Environment

INTEGRATED RESOURCE PLANNING

OCT 10 1995

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Serving the Rocky Mountain West

October 5, 1995

Ms. Nancy Esteb
Manager, IRP
PacifiCorp
825 NE Multnomah
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Portland, OR 97232

Dear Nancy:

Thank you for giving the Land and Water Fund of the Rockies an opportunity to comment on PacifiCorp's draft RAMPP-4 report. We appreciate your continuing efforts to facilitate our participation in the RAMPP process, as well as the careful attention that you have given our comments in the past.

Overall, we are impressed with the draft report. The quality of the technical analysis is high, and the results and conclusions drawn from the model runs are more clearly presented and better explained than in previous reports. We believe that the RAMPP-4 strategy of limiting the number of model runs so that critical areas of concern could be more thoroughly analyzed worked well. For the most part the scenarios were well thought out and carefully designed, although, as discussed below, we believe that better scenarios could be developed to analyze the risk of proposed resource acquisitions. We have no objection to using a similar approach in RAMPP-5, as long as the scenarios are carefully designed and fully address the critical issues.

In general, we support the proposed Action Plan. We are pleased that demand-side management remains an integral part of the plan, and we strongly support your commitment to bring existing wind projects on-line by 1996 as well as your plans to pursue new agreements to acquire additional wind and geothermal power. We believe that these activities will produce significant economic, risk diversification and environmental benefits for PacifiCorp and its customers.

In addition, we are generally supportive of the move away from the coal-fired resource plan of RAMPP-3 to the natural gas-based plan of RAMPP-4. We believe that natural gas has distinct environmental advantages over currently available coal technologies. These include virtually no sulfur dioxide emissions, and

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lower emissions of carbon dioxide, toxics, and particulate matter. Lower emissions reduce air pollution and its harmful effects on human health and lessen the risk of global climate change. Moreover, we agree with your position that the lower emissions of natural gas-fired resources reduce the risk to PacifiCorp and its customers of the possible adoption of more stringent environmental regulations.

We also agree, however, with PacifiCorp's view that the major disadvantage of gas-fired resources is the uncertainty surrounding future natural gas prices. Our principal concern with the report is that, while the risk of an unexpected increase in the price of natural gas has been acknowledged, possible resource acquisitions to mitigate this risk have not been explicitly analyzed.

We suggest that PacifiCorp develop a scenario to explicitly model the impact of a natural gas price shock on the company's resource acquisitions. We realize that PacifiCorp does not have to make a decision for new baseload gas-fired resources during the action plan period for RAMPP-4, and that the company believes the most prudent course of action is to carefully monitor gas prices and other key variables and re-examine the action plan if these variables change significantly. We believe, however, that the risk to PacifiCorp and its customers arises primarily from a situation in which the price of natural gas remains low until the lead time for gas-fired resources requires a decision, and then rises after the company has committed to new gas-fired capacity. The impact on rates and total resource costs of this scenario needs to be analyzed to adequately address the fuel-price risk associated with acquiring new natural gas-fired capacity. This type of risk analysis is especially important for natural gas prices given the difficulty of predicting future gas price movements and the sensitivity of the preferred resource plan to changes in their level, as shown by the dramatic shift from coal-fired resources to gas-fired resources between RAMPP-3 and RAMPP-4.

We believe the natural gas-price risk analysis will provide added support to the action plan commitments to acquire renewable resources, will help quantify the risk diversification benefits of renewables and may show that when fuel-price risk is properly treated more renewable resources are justified. We also believe that the analysis will help PacifiCorp address the Utah Commission's recommendation in their acknowledgment of the RAMPP-3 report that RAMPP-4 should more explicitly analyze risk.

Given that we are making this suggestion late in the process, we understand that it may not be possible to include the gas-price risk analysis in the RAMPP-4 report. We hope, however, that it will be included in RAMPP-5.

Once again, thank you for giving us the opportunity to comment on the RAMPP-4 draft report. We look forward to continuing our dialogue with PacifiCorp.

Sincerely,

Eric Blank, Director
John Nielsen, Policy Advisor
LAW Fund Energy Project

DEPARTMENT OF ENVIRONMENTAL QUALITY
ENERGY DIVISION

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October 6, 1995

Nancy Esteb
Manager, IRP
PacifiCorp
825 NE Multnomah
Suite 625
Portland, OR 97232

Re: Comments on PacifiCorp's RAMPP-4 Draft Report

Dear Nancy,

The following comments address editorial corrections and areas in the report that need further clarification. These comments are in no way a "draft" of RAMPP-4 comments that will be sent to Montana Public Service Commission (Commission). However, any area that is not clarified will likely appear again in comments to the Commission.

The comments go primarily chapter by chapter, however, the following are a few general thoughts that came up as I was reviewing the report.

1) Since RAMPP-4 is not a stand alone document, the RAMPP-4 report should reference specific pages in the RAMPP-3 document when discussing it.

2) All tables and graphs in the RAMPP-4 report and appendices should be labeled with units (e.g. megawatt hours). Further, if only part of an appendix table is included in the report, these tables should reference the relevant appendix tables.

3) A section on the potential benefits, costs, and risks of company transactions that were not included in the model runs (e.g. the Columbia Falls Aluminum Company and Clark County PUD contracts) should be included in the RAMPP-4 report. This section should address how much sooner additional base-load resources are needed and the potential price impacts with these transactions in place given varying levels of load growth. Further, the specifics of these agreements should be included in the discussion (e.g. amount, price, interruptible, etc.).

4) The discussion of total resource cost should be expanded throughout Chapter Five instead of just three sentences at the end of the chapter.

5) The action plan should include a section that is explicit in how it meets different objectives (share-holder, customer, societal, etc.).

Chapter 3: Input Update

Page 5:
The report should reference the load forecasts in the appendix tables. Further, the appendix should show how the load forecast change by state between the two RAMPP processes.

Page 16:
The report should review the difference between the least cost plan's starting gas price and the current gas price and discuss any significant impact that this difference may have on the results of the analysis.

Chapter 5: Modeling Results

Page 1:
The report should explain in more detail that PacifiCorp is a winter peaking utility in so far as its native load customers are concerned, but when wholesale sales are included, PacifiCorp is a summer peaking utility.

Table 5-1 and the whole discussion in Chapter 5 of the report is inconsistent with the tables in Chapter 3 of the Inputs Appendix and with the whole Results Appendix. In particular, the values for existing generation and combined cycle CT are inconsistent.

Table 5-2's title should be more specific and include Utility Cost. As mentioned above, Table 5-2 should also reference the tables in Results Appendix that contain the rate information.

Page 3:
In case 1, the 109 MW summer peak purchase of gas-fired resources should be referenced to the Results Appendix.

Page 5:
In case 4, the second paragraph should be clarified. As written, the report has two lines that seem to contradict each other when discussing PacifiCorp's peaking resources (...the company has more winter peaking resources available to it...the company currently has more summer peaking resources available to it...). Further, the last sentence of the third paragraph should also be corrected (...the model additional resources...).

In case 5, the report should discuss why the 150 MW turbine upgrade causes a 209 MW reduction in existing generation under winter peak capacity.

Page 6:
In case 6, again the report should discuss why the 474 MW Hermiston plant causes a 552 MW reduction in existing generation under winter peak capacity.

Page 24:
The level of DSM in the base case (446 MW) is inconsistently referred to when making comparisons to cases 71, 72, and 73. Further, the level of DSM that is selected under case 71 is referred to as being 539 MW. This is inconsistent with the value in Table 5-1.

Page 25:
5071 MW of gas-fired resources mentioned in case 72 is inconsistent with Table 5-1 (4359 MW). Further, the discussion states that the model adds 500 MW of geothermal and 400 MW of wind, Table

5-1 shows only 712 MW of renewables being added. The Results Appendix for case 72 also shows 712 MW of renewables of which 500 MW is geothermal and 212 MW is wind.

Page 26:
The same comment applies to the discussion for case 73 as for case 72. 5876 MW of gas-fired resources is inconsistent with Table 5-1 (4710 MW). As far as renewables, the Results Appendix states there is 566 MW of wind instead of 1200 MW as stated in the discussion.

Chapter 6: Action Plan

Page 25:
The report should address what load level causes the need for summer peaking purchases, and further, it should explicitly state that summer peaking purchases are the least cost peaking resources until the year 2003 in all cases given the summer peaking price assumption.

Page 26:
The second paragraph under gas-fired base-load resources states that the model selects 2221 MW of gas-fired resources instead of 2251 MW which is in Table 5-1.

The report should explicitly state that under the medium-high load growth case that base-load resources are required by the year 2000, and because of the four-year lead time on base-load gas-fired resources, an action plan decision may be required as early as the year 1996.

Page 27:
Graphs 6-5 & 6-7 should be titled graphs and not tables. The sub-title in Graph 6-7 should either be Winter MW or the graph should be corrected using the correct summer peak capacity values.

Sincerely,

John Goroski

John Goroski, Economist
Energy Division

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Memo:
To: Nancy Esteb, Manager IRP
From: Rich Collins
Re: Comment on RAMPP-4 Draft
Date: October 5, 1995

General Comments

Generally, I would say the RAMPP-4 process went a lot smoother than RAMPP-3. You avoided last minute surprises that proved so disruptive last time. The meetings for the most part were well run and productive. It should be noted that RAMPP-3 was a more ambitious project and was also hampered by breaking in a new model.

One important difference I detect in RAMPP-4 is the change in its objective. It appears that most of the analysis is centered on price impacts rather than on the objective function required by your Standards and Guidelines promulgated your various Commissions. This is particularly true for Chapter 5, the discussion of model results; all the discussion is centered on price impacts. The discussion must be expanded to include an analysis of cost impacts, in particular total resource costs. You should include a section on why you decided to change the emphasis and justify your reasons for doing so. Any discrepancies between the two objectives, least cost and price should be made explicit. You should identify if your action plan deviates from least-cost and then discuss why it deviates and explain the risks associated with such a deviation..

You should consider, if possible, running some additional scenarios. I would suggest a high and low load growth, to reflect the possibility of dramatic changes in market share due to competitive entry. This should be done if you have time. However, you should redo Case # 50, the underbidding scenario and change your assumptions about non-firm prices. These prices are unrealistically high.

Your report should not end with a discussion of Demand-Side, in fact this chapter should be before your action plan chapter. In addition, you should include a summary or conclusion chapter to recap your major findings.

Specific Comments

Chapter 1

P. 1 I would include a sentence after end of second paragraph that indicts what percentage of total sales, wholesale sales constitutes. In addition, I thought retail sales were 1/3, 1/3, 1/3, industrial, commercial and residential? Or is that just in Utah?

INTEGRATED RESOURCE PLANNING

OCT 16 1995

P. 3 Change last sentence to - "According to economic theory, competition is an efficient way to organize industry when there are a large number of buyers and sellers, no barriers to entering or exiting the industry and information is readily available." You should expound on competition as an efficient form of structure and identify those conditions which pertain to the electric industry at this point in time .

P. 4 If PacifiCorp expects a situation of excess power for 5-7 years and maybe 10 years or longer, why not just purchase all new capacity from the market? This should be discussed somewhere in the report.

P. 7 In your discussion of alternative forms of regulation, you mention the need for the Company to accept the benefits and costs of risks in the wholesale market. You should knowledge that some regulators feel that ratepayers have already accepted the majority of the risks for wholesales sales by allowing the Company to acquire assets before native loads requires them.

P. 9 When discussing some possible consequence of FERC NOPR, what time frame are you contemplating when you state "Generally lower but possibly higher power prices"?

P. 10. Wholesale sales - The Company notes that margins on wholesale power sales are in decline causing an upward pressure on retail rates if the company cannot maintain the currently level of wholesale contribution. This seems to be a reaffirmation by the Company that the risks of wholesale sales are on the ratepayer. In the next sentence, you state that the company must take on greater risk to achieve the same level of wholesale contribution. How does this jibe with this belief that ratepayers assume the risk of wholesale sales?

Chapter 2.

Compliance with Utah RAMPP-3 acknowledgment order

4. RAMPP-4 should provide a suitable risk analysis to better explain why the action plan differs from least cost principles and to quantify the benefits and cost of such deviation. The Company's response does not meet this request, what steps will you take to comply with the Commission's order?

8. RAMPP-4 should analyze potential impacts on the IRP process brought about by a competitive restructuring of the electric industry. What about using the high and low forecasts and see what the impacts will be?

The Company recommend the following changes for IRP

1. IRP for only regulated portion of business (Disco IRP)
2. Broaden least cost definition to include price impacts.
3. Need to keep competitive information confidential
4. More flexibility in action plan
5. Shorter time horizon

Do these suggested changes need to be codified in a revised Standards and Guideline for IRP?

Chapter 3

General: I am concerned about use of these forecasts for things other than IRP. For instance, the FERC NOPR suggests that wholesale transmission availability known as ATC (Available Transmission Capacity) will be determined as the difference between total line capacity and the capacity necessary to meet native load. FERC more than likely will rely on load forecasts from the Company's IRP. These forecasts are not the latest of the Company and do not reflect current information about how loads have changed in different geographical areas. The Company should put a disclaimer in the IRP to recognize this fact so FERC will know not to rely on these extended forecasts for use in calculating ATC. Please acknowledge in the report that the load forecast should not be used for calculating ATC.

Load Forecasts for RAMPP-5 should include the possibility of loss of load and also greater wholesale loads.

Existing System -
Correct the analysis of Gadsby so it is not so confusing. Just include the incremental power rather than the present method.

P. 9 Fourth paragraph discusses system efficiencies, you need to be able to say that these are least-cost. Again, it would have been preferable to include them as resources for the model to choose.

P. 10 I'm confused about the difference between the refurbishment and the turbine upgrades, can you clarify? You should attempt to model all of these efficiencies, upgrades and refurbishments, so the model could choose when to implement them.

P. 19 Wind resources - are you backing away from your past commitments for wind, in that the economics of alternative resources, i.e., gas power turbines, has changed?

P. 26 I question the correlation between wholesale prices and that of gas escalation rates. If there is indeed excess capacity in the regional market, then the wholesale prices will be determined by the variable cost of the excess capacity not the cost of new resources. This needs to be clarified in your discussion.

P. 29 Revisions to inputs
Does the model choose the APS Cts or are they hardwired in? If chosen, when? If hardwired in, you should explain your rational for not modeling them.

What are the assumed escalation rates for wholesale sales ? Specify.

Chapter 4.

P. 11 Typo, you use 300 Mws in title and 600 MWS in discussion.

Chapter 5

P. 5. 8th line down, Should you replace "more" with "less" in front of the word summer?

P. 7 Shouldn't this scenario have been run with low gas prices? This is a more realistic scenarios and tell us more about Hermiston's acquisition. What about the possibility of canceling this project, what are the replacement costs of other cogeneration, they need to be in line with current estimates, for instance the ACME project.

P. 8 Case #11, First sentence, last paragraph. Change sentence to "It is difficult to interpret the financial impact of 20% lower DSM costs." Why did the Company choose not to include the assumed lower DSM costs in its financial analysis? Both methods should be done and reported.

P. 17 Case #50, In this under building case, we need more a realistic estimate of non-firm market prices, 2 mills above the cost of cost of a combined cycle CT appears to be too low. In the RAG meeting when I brought this up, there was some discussion about differentiating firm and non-firm power. I am still confused, if anything non-firm power will be even less than firm power so how is this at all realistic? I strongly suggest that this scenario be rerun with realistically low non-firm prices. Maybe 13-16 mills. This is particularly true when there is excess capacity on the market.

P. 21 Case 61, How do the results of the renewable case affect your investments in the Wyoming and Washington wind projects?

P. 24 and 25 Cases 71 and 72, The analysis of the costs to reduce CO_2 emissions gives a false impression of the impact of such adders. In most cases, rather than reconfiguring the system, the Company would purchase CO_2 offsets or purchase emission permits. If ever there was a pollution problem that could be handled with tradable permits, it is CO_2.

P. 27 4th paragraph last sentence. Add supply-side in front of choice i.e., least expensive supply-side choice.

P. 28 Does the assumption that there is a much lower wind availability affect the resource selection? Maybe you should explain why you changed this assumption.

P.28 Findings This discussion should center more on the effects that load growth, gas prices etc. have on costs and how that will influence your actions plans.

P. 31 You need to expand your discussion of environmental adders, I'm not sure this will meet the requirements of the Utah Guidelines. There should be some discussion of risk and strategies to mitigate the risk of future internalization of environmental externalities. Is this discussed in more detail in another section?

Chapter 6.

I would suggest that you remove the entire section on Consistency of Past Acquisitions with RAMPP Actions Plans and put it in a separate chapter. Inclusion in this chapter appears that acknowledgment of the action plan also acknowledges your discussion of consistency.

P. 4 e) Please give an update of the Solar II project and discuss whether it will continue to run after its two year trial. If not, why not?

P. 19 Other Opportunities. I'm not sure how you can draw this conclusion, you do not provide any analysis that supports this. Either delete this section or explain how you drew this conclusion and specifically what model runs are used to substantiate this action plan item.
In particular how is this consistent with finding on page 20 "**The single most significant principle in the RAMPP-4 action plan is this: the wisdom of postponing decisions.**"

P. 28 First full paragraph, Your discussion of cases #6 and # 7 seems to focus on the why the acquisition of Hermiston is beneficial to ratepayers. However, in order to draw that conclusion you need to run a scenario with low gas prices. So I recommend that you either do so and report the results or that you qualify your conclusion and acknowledge that analysis of a low cost scenario is necessary before one can draw any conclusion about benefits to ratepayer.

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INTEGRATED RESOURCE PLANNING
OCT 6 1995

October 5, 1995

TO: Nancy Esteb
Manager Integrated Resource Planning

FROM: Mary Cleveland

SUBJECT: Comments on PacifiCorp RAMPP-4 Draft Report.

GENERAL COMMENTS & OBSERVATIONS:

Although there has been an emphasis placed on the "price impacts" of various resource alternatives throughout the RAMPP process, it would appear that "price impacts" as such were not driving the planning process, but rather used to judge the outcomes of various scenarios, which were designed to determine if and under what circumstances the Company would be able to postpone and/or mitigate the need to commit to significant capital expenditures in the near future. In other words, going into the RAMPP process, PacifiCorp's management, not unlike other electric utilities as evidenced by the current literature, had determined that given the changing environment of electric utilities operations, commitments to capital expenditures for the purposes of serving firm loads should be postponed or mitigated to the extent possible.

Next, it would appear that Company management determined viable options to accomplish this objective. These are evidenced by changes made to RAMPP-4, which include:

1. Lowering of the planning reserve margin from 15% to 12%.
2. The inclusion of a summer peak purchase option through 2002, since the summer peak was currently driving resource needs.
3. Reducing the lead time required for a coal plant (i.e. including SCR technology would reduce permitting time).
4. Turbine Upgrades (i.e. looking for cost-effective ways to maximize use of Company assets).

Items 1, 2 and 4 were included in the IPM model. The model was allowed to compare the summer peak purchase to and select it over other resource options.

Having decided upon these options, the IPM model was run. Based on the inputs to the IPM model as well as the options previously decided on by management, it was determined that no major resource additions were needed until 2003. Therefore, the draft report concluded that no decisions needed to be made. But, in reality a decision has been made---to find all cost-effective alternatives to postpone and/or mitigate the need for capital expenditures to meet firm load requirements. The conclusion that no decisions need to be made is really a misnomer. What the report actually concludes is that currently, based upon load forecasts and other planning assumptions, the Company does not have to commit capital expenditures to meet firm load requirements.

CHAPTER 1:

Competition:

The report is silent on competition from other fuels. For example, new gas technologies are currently being developed for the paper industry. At the most recent NARUC Subcommittee on Accounts meeting, a representative from Northwest Natural Gas Company stated that natural gas fireplaces are capable of heating a good sized area, can be used in electrically heated homes in the Northwest where there is not adequate ducting for gas heat and are remote controlled making them attractive. The natural gas industry is currently committed to developing new technologies to expand its market.

CHAPTER 2:

No Comments.

CHAPTER 3:

Geographic Areas and Transmission Limits:

see #1

Map 3-1, shows the transfer capability between UTA and DSW to be 530 MW in 1997. However, the language beginning at the bottom of page 4 and continuing on page 5 states, "The UTA to DSW path increased from 450 MW in RAMPP-3 to **485** MW by 1997 for RAMPP-4."

Map 3-1, shows the transfer capability between DSW and UTA to be 450 MW in 1997. However, the language contained in the first paragraph on page 5 states, "In RAMPP-3, the DSW to UTA pate was 425 MW; in RAMPP-4 it is **485** in **1996**."

The whole paragraph at the top of page 5 does not make any sense. I have attached a handout from the December 9th meeting which discusses the changes to "geographic and transfer capabilities". . .

For the DSW to UTA line. The path decreased 35 MW due to firm wheeling provided to UAMPS for their San Juan 35 MW purchase. Following the completion of the Glen Canyon-Navajo interconnection in 1997, it will increase 250 MW, but this increase will be offset by 190 MW due to firm transmission service to WAPA.

For the UTA to DSW line. Following the completion of the Glen Canyon-Navajo interconnection in 1997, this path will increase 230 MW, but this increase will be offset by 150 MW for additional wheeling to UPS. The draft text states the increase in this line's capacity is due to "the new 150 MW wheeling contract with APS"!!!

Load Forecast:

On page 8, the third paragraph, which discusses whether the changes in the load forecast effect DSM availability....the last sentence of the paragraph should probably be changed to read, "RAMPP-3 assumed on DSM activity in that sector, **therefore DSM availability was not effected.**

Table 3-8:

"sumd" should read "wind".

Firm Wholesale Contracts:

On page 12, the text states, "RAMPP-4 incorporates these new contracts, which include... On page 13, The Clark County PUD Storage and Integration Service Agreement is listed, although RAMPP-4 does not incorporate this contract.

Also on the Clark County PUD Interim Sale (page 13), does PacifiCorp deliver 100 MW in each of the three years, or 100 MW during the three years?

Gas Prices:

Although not explicitly stated, a basic planning assumption has been made that the Company will be able to continue buying gas using short-term contracts. It would be helpful if these types of assumptions could be laid out.

Coal Prices:

Page 17, Wyoming $6.50 per ton coal not included in the writeup, although included on Graph 3-17?

Supply-Side Portfolio:

Solar is not included in the discussion of changes to the supply-side portfolio since RAMPP-3, although it was included as an option in RAMPP-3 and not included as an option in RAMPP-4 because it would never be picked...too costly to even consider.

Also Hunter 4 is not discussed. In RAMPP-3 it was lumped with Utah coal, but in

RAMPP-4 is treated as a separate resource.

Gadsby Repowering (page 18). Would add 320 MW (Minutes 12/9, pg 16).

Pulverized Coal (page 18). Although the inclusion of SCR equipment would increase operation costs 25% (Minutes 12/9, pg.14), it is believed that it would reduce the permitting time.

Wind (page 18). The text states that the development of wind in Utah would take longer, however on Table 3-18, Utah Wind Farm also shows the first year available to be 1998?

Summer Peak Purchases (page19). The $2/kw month price is based on the Oregon avoided cost filing.

Page 20, middle paragraph, last sentence, states "The next **three** columns provide emission rates. . .however, Table 3-18 only has two columns that provide emission rates. The table of potential resources handed out at the December 9th meeting did in fact have three columns that provided emission rates, NOX, TSP and CO2. I also noted that the heat rates on Table 3-18 differed from those on the December 9th handout...the incremental and average are reversed? I've attached the December 9th handout.

Tables 3-19, 3-20, 3-12 and 3-22 also contain data which in some cases differs from that provided on December 9th?

et
H #2

Transmission Costs:

Since IPM treats everything as $ per KW, than how wind capacity is handled makes a difference. If power line not built at full capacity costs would decrease. (Minutes, 12/9, pg. 22). Since IPM assumes the power line is built at full capacity is the cost of wind in reality overstated? Please discuss.

Non-Firm Markets:

On page 26, third paragraph. It should be made clear that the non-firm market price of 19 mills on-peak and 16 mills off-peak was used for both non-firm purchases and sales.

On page 26, forth paragraph. Allowing only 80% of the non-firm price to vary with the gas escalation rate was based on the assumption that not all costs could be passed through to customers and competition with coal and nuclear producers would slow price growth. Once again this assumption should be stated.

See AH #3

Reserve Requirements:

Most of the comments I have received from others in my office have centered around the reserve requirement. Refer to attached memo.

I believe it would be helpful to have a discussion about the current operating reserve requirements imposed by the Pacific Northwest Coordination Agreement, the WSCC and the InterCompany Pool (ICP). For example, on May 5th, Greg Duvall stated that the Company currently carried operating reserves of 7%thermal and 5% hydro. This assumes a lost of load probability of one loss in 20 years. (Minutes, 5/5, pg. 27).

I believe the "No Summer" run would reflect the lowering of the planning reserve requirement to approximately 8%. Reducing the planning reserve any further would result in violating the operating reserve requirements.

In reviewing the minutes of past meetings, I noted the following, which are not specifically addressed in your discussion:

1. In RAMPP-3 the reserve margin contribution for wind was a function of the average generation out of the plant for the entire year. In RAMPP-4 the average generation for the specific season was used.
2. Hydro contribution to the reserve is based on 50 year average.
3. DSM contribution is deducted prior to applying the reserve requirement percentage. (Note: Does this mean that you can't do DSM to fulfill the reserve requirement?)

It may also be useful to discuss what the various resources contribute to the reserve margin.

Revisions to Inputs:

I believe based on discussions at the most recent PITA meeting, that the Wyoming load loss is greater than expected, now 160 MW.

CHAPTER 4:

Model Changes Since RAMPP-3:

Other model changes since RAMPP-3 not mentioned:

Resource Mix Capability---enables specification of annual and cumulative limits on new resource additions by type.

Wind no longer modeled as hydro.

DSM:

Didn't RAMPP-4 force IPM to take lost opportunities?

Original goal was to use the IPM model to optimize penetration rates for DSM resources. However model as currently coded picked timing, but not penetration. Therefore, ramp rates were assigned.

I believe there should also be a discussion about how the various bundles of measures were derived.

CHAPTER 5:

Introduction:

Page 1, first paragraph under Introduction, 5th line down, very end of line, there is a typo; "may" should be "make"..."the company does not have to **make** any decisions..."

Case 4, With No Summer Data:

On page 5, beginning forth line down from top of the page the discussion reads:

> "PacifiCorp's system is more stressed in the summer than the winter because the **company has more winter peaking resources available** to it than summer peaking resources......However, because the **company currently has more summer peaking resources** available to it.

Towards the end of the second paragraph on page 5, the discussion reads:

> **The winter reserve margin reached 12 percent before the summer reserve margin.**

This discussion is obviously in error and needs to be corrected.

Case 12, With 20% Advantage for Conservation:

It is my understanding that this run was made because some members of the DSM technical advisory group felt that the DSM prices being used were too high . . . that these prices had come down. But, since the original DSM costs were used for financial reporting, the financial impact effectively ignored the possible overstatement of costs. Members of the technical advisory group did not view this run as artificially lowering the cost of DSM.

Were the original DSM costs also used for financial reporting purposes in Cases 13 and 14?

Note the last paragraph on page 8. The financial model does contain a 15% cost advantage for DSM (Refer to Chapter 6, page 24). Therefore, for financial purposes DSM costs were [redacted] lowered by the additional 5%, not 20%. The original DSM costs for financial reporting do in fact include the 15% advantage.

Case 59, With 300 MW Added Transmission from Utah to OWC:

Description under case header (page 20) states, "This case increases the transmission path from Utah to OWC by **600** MW... Is it 300 or 600?

Environmental Adders Cases: (Page 23)

There were a couple of changes since RAMPP-3 that had a significant impact on the outcome of the environmental adders cases, which should be discussed. In RAMPP-3 each unit was required to run, so existing resources were not replaced as they are here. (Ref.

Minutes, 3/17, pg.21). Also RAMPP-3 assumed unlimited wind power, RAMPP-4 did not. Actually, these items are discussed on page 28, but should they also be noted when discussing the environmental adder cases?

David Cohen, RMI made a comment to the effect that if you're going to use environmental cost adders then you should escalate the non-firm sale price as well, under the assumption that everybody would be faced with the same environmental adder. I presume the non-firm purchase price would have to increase as well. Had this been done, would the results have changed? Should his point be addressed?

CHAPTER 6:

DSM Activity:

On page 23, second paragraph where the reasons for using the DSM amounts in Case 13 is being discussed. It should also be noted that the 15% adder is also consistent with the financial analysis.

On page, 24, third paragraph, which discusses inputs to the cash flow analysis. It needs to be clear how **power cost savings** are defined. These savings represent an "opportunity value". See Minutes, May 5, Page 3.

CHAPTER 7:

See Att #4

Pages from draft report with comments are attached.

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INTEGRATED RESOURCE PLANNING
OCT 13 1995

MEMORANDUM

TO: Dr. Nancy Esteb, Manager
Integrated Resource Planning, PacifiCorp

FROM: Ms. Rebecca Wilson, Utility Economist RLW
Division of Public Utilities

DATE: October 10, 1995

RE: Comments to PacifiCorp on the Draft RAMPP-4 Report

The following memo provides comments and recommendations on the RAMPP-4 draft report and technical appendices. Because of serious injuries Ken Powell sustained from a recent auto accident, Ken's comments are not explicitly reflected in this memo. Ken made several suggestions in the last RAMPP-4 RAG meeting; perhaps you could review the meeting minutes in order to address the suggestions he raised. Ken is making a swift recovery and if he should return in time for you to incorporate his additional concerns and suggestions on the draft, we would appreciate reserving that opportunity. We are now expecting Ken back in three weeks.

Overall, we are very pleased with this draft report and technical appendices. We recognize the significant analytical and organizational effort embodied in the draft. We also appreciate this opportunity to comment in writing.

We have two major requests for the final report to ensure greater consistency with Utah Public Service Commission Standards and Guidelines on IRP: least-cost and trade-off analysis; and risk analysis. We appreciate that this requires additional work. However, the Utah Public Service Commission requested that PacifiCorp spend more time analyzing the study results in

RAMPP-4 prior to filing a final report,[1] therefore, we suggest that it is important enough to justify the additional work. The analysis you provide in response to this request in RAMPP-4 can be built upon and modified as necessary in RAMPP-5.

We also provide detailed questions, suggested clarifications, additions and deletions, and note suspected typographical errors by chapter and page number.

Additionally, we suggest that RAMPP-5 meetings begin sooner than mid-summer 1996. It appears that substantial discussion about the role and goal of least-cost planning for RAMPP-5 is needed. We think it would be most beneficial for that discussion to occur prior to the development of model runs, etc. Perhaps early spring would be appropriate.

Least-cost and trade-off analysis

In both Docket No. 90-2035-01, *Report and Order on Standards and Guidelines,* and Docket No. 94-2035-05, *Report and Order on Acknowledgment of PacifiCorp's Integrated Resource Plan, RAMPP-3,* the Utah Commission indicated that the process should result in the selection of the optimal set of resources given the expected combination of costs, risks and uncertainty.[2] Trade-offs between costs, emissions, price-impacts, etc., should all be considered and evaluated. We suggest that the analysis in Chapter 5 which is focused on "price" impacts is not within the spirit of these Utah Commission orders.

Risk analysis and identification of who will bear risk

In both Docket No. 90-2035-01, *Report and Order on Standards and Guidelines,* and Docket No. 94-2035-05, *Report and Order on Acknowledgment of PacifiCorp's Integrated Resource Plan, RAMPP-3,* the Utah Commission requested risk analysis associated with various resource options.[3]

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[1] Utah Public Service Commission Report and Order on Acknowledgment of PacifiCorp's Integrated Resource Plan, RAMPP-3, pages 21-22, 27. See Attachment A.

[2] See highlighted sections of Attachment B.

[3] See highlighted sections in Attachment C.

RAMPP-4 DRAFT REPORT

Chapter 1 page 10: Last sentence in first paragraph which states that "For comparability to be successful, all transmission owners will have to provide open, competitively priced transmission services." What is meant by "competitively priced transmission services"? It is my understanding that transmission will remain a monopoly function and price regulated by FERC. In fact the second sentence in the last paragraph appropriately states, "FERC will probably continue to require transmission-owning utilities to use embedded pricing... rather than market-based pricing."

Chapter 1 page 9-11: On page 9, it is stated that one possible consequence of the proposed FERC rule may be, "generally lower, but possibly higher, power prices." On page 11, it is stated that "PacifiCorp expects to be able to increasingly rely on the wholesale market to meet its power needs, both from the non-firm market and from longer-term contracts." It appears that this strategy carries the risk of higher prices; who will bear the risk of the new strategy?

Chapter 2 page 1: Utah has a regulatory requirement to provide risk analysis and to identify who would bear the risk, ratepayers versus shareholders, given a particular strategy and likely outcome. Please see attached documents. We also attach the six page definition of Utah Standards and Guidelines for IRP for PacifiCorp.[4] We attach this list should you elect to add a section in RAMPP-4 with the regulatory requirements of each jurisdiction as suggested by Ken Powell at the last RAMPP-4 meeting.

Chapter 2 page 9: Again, Utah has a requirement that risk analysis be conducted and provided.

Chapter 2 pages 13-15: On page 13, last paragraph, PacifiCorp notes that IRP makes sense for the non-competitive, regulated part of the business but not for the competitive part, i.e., wholesale customers. Isn't this currently how IRP is done? It is my understanding that IRP is not done to meet non-existing wholesale requirements. On page 15, second to last paragraph, PacifiCorp notes the desire to shorten the time horizon for IRP. Why would the needs of the non-competitive customers change? Why would the longer horizon no longer be appropriate for the regulated sector of services?

If higher prices may be the result in the wholesale market and captive customers will lose

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[4] See Attachment D of this memorandum. (Originally entitled Attachment A to Docket No. 90-2035-01.)

long-term benefits by shortening the planning horizon, what are the benefits to society of competition?

Chapter 3 page 3: First sentence in first full paragraph (not bullets) states that PacifiCorp has enough transmission capacity in each geographic area it serves to meet local load requirements.... please state the time period assumed in this sentence.

Chapter 3 page 4: Fourth paragraph, last sentence, "usually a path with a large load at the sending end has a larger capability than one with a large load at the receiving end", is this right? The pattern looked generally the opposite to me.

Chapter 3 Map 3-1 and page 5: The numbers in the text on page 5, first paragraph, do not all correspond to the numbers shown in Map 3-1.

Chapter 3 page 6: First paragraph, please provide more state specific detail, i.e., what occurred for each state. Also, please provide full discussion of why Alternative #1 was selected. It looks like Alternative #3 was the most correct approach; what was the difficulty in using that approach? Also, some explanation of why new load forecasts were not used and how this could impact RAMPP-4 conclusions. This will help address the Utah Commission guideline noted on page 37, item 4.a.ii, in Attachment D to this memorandum. This guideline refers to the analysis of how various economic and demographic factors, energy prices, end-use efficiency, will affect future loads.

Chapter 3 Table 3-2: Should the numbers in the tables be negative? Intuitively, it looks like the numbers under alternative 1 and 2 are reversed. It makes sense that load would be lower if you adjust the service territories with lower load expectations than when you adjust for that lowered load expectation plus adjust for service territories with higher load expectations. Yet, adding the higher load territories in alternative 2 *further decrease* load expectations. What were the differences on a winter and summer peak basis?

Chapter 3 page 8: Last sentence, please make clear here or elsewhere the impact of this statement given that the planning period peak that triggers resource additions includes existing firm wholesale sales which means that total requirements are summer peaking.

Chapter 3 page 9: Last paragraph, this discussion appears to be misleading. It is misleading to say that operation and maintenance expenditures can produce the total amount of power. If this is the cost you have to incur to keep this amount of megawatts in the system, it is an operation and maintenance item and should simply be counted in the cost of the existing system. If you make these expenditures and *increase* the number of megawatts available, which is what I think of when I think of an increase in the efficiency of the plant, that you get more for less, then you would divide the cost by the incremental increase in megawatts to get a cost per MW.

<u>**Chapter 3 Table 3-8:**</u> Wind is mistyped as "sumd".

<u>**Chapter 3 page 10 Table 3-10:**</u> The numbers in the mid-section of this table appear to be mistyped. They don't add up.

<u>**Chapter 3 page 15 and Table 3-12:**</u> Last sentence in paragraph on penetration rates, 4 percent of what, i.e., technical kWh potential, number of buildings, square feet? Table 3-12 footnote (1) percent of annaul (sic) new construction, *in square feet, number of buildings...?*

<u>**Chapter 3 page 17:**</u> Last sentence in first paragraph of "Supply-side Portfolio" discussion; were indirect costs also included in RAMPP-3 or is this new in RAMPP-4?

<u>**Chapter 3 page 21:**</u> Last sentence in second paragraph does not make sense. Maybe should read "The formula to calculate mills/kWh *in* the "Ttl Capital & Fixed Cost" column *is the sum of annual pmt and O&M* times 1000...." Third paragraph: could you state how Levelized mills/kWh converts real levelized cost into mills/kWh?

<u>**Chapter 3 Table 3-20:**</u> Although it was pointed out in the Sept. 21 meeting that all "Gadsby" numbers would be changed, just thought I'd note that the cost on this table does not match the cost on Table 3-19.

<u>**Chapter 3 page 29:**</u> Typo in fifth paragraph, second sentence, differen*t*. Last full sentence on page; in light of "Update to Updates", will you be changing this sentence to read that the estimates are *not* reasonable estimates of the longer-run price structure of that market? Please note here the conclusions you drew from this change which were noted on the handout entitled "Changes Since IPM Inputs Locked".

<u>**Chapter 5 page 1:**</u> Typo in second paragraph, fourth sentence; *may* should be *make*. Third paragraph; again, could you clarify that *total requirements* peak in the summer and that this is the basis upon which resources are added. Ditto on page 5, first paragraph, second full sentence. **Also, in this section, please add TRC analysis and impact on emissions in addition to price impact analysis.**

Chapter 5, Table 5-1: In the heading of this table, could you include all assumptions that are common to all runs unless otherwise noted? For example, do all runs assume medium load and medium gas unless otherwise noted?

Chapter 5, Table 5-1, page 3 of 8 and page 14: The text for Case #41, the lumped resource additions run, indicates that high gas prices were coupled with this run. Why was this done and did you also run a case with medium or low gas prices? If so, what were the results? If you plan to run additional scenarios, this is one I'd like to see.

Chapter 5 page 7: Did you run a "without Hermiston, and low gas price" case? This would be interesting since this appears to be a likely scenario. Again, if you run additional cases, this is one I would recommend.

Chapter 5 page 13: I found the discussion on this page to be confusing. Could you take a stab at rewriting it? For example, the first sentence of the third full paragraph that begins with "Customer" does not appear to describe this case. It states that prices would be lower but is unclear what the point of reference is, i.e., lower than what? The paragraph may address the linked case rather than the subject heading unlinked case; is this a typo? Shouldn't the discussion focus on the impact of the unlinked case rather than what would have happened in another case? Is the meaning of this whole paragraph that breaking the link means higher prices than not breaking the link? Or is it in comparison to the base case?

The next paragraph appears to be a summation of the impact of gas price assumptions on different model runs rather than further analysis of the impact of this one case. It doesn't seem to fit here because it breaks up the flow of discussion on this one case. The next paragraph resumes discussion but I don't follow the point. The first sentence discusses utility cost and I think implies that levelized "price" doesn't change from the base case when gas prices and non-firm prices are linked; this outcome appears to be true in the early years but not overall; price is increased over all according to Table 5-2. Same with the next sentence... higher customer prices *than base case or linked case or both?*

Chapter 5, pages 16 and 17: Is it correct to assume that the non-firm prices in these sensitivities are linked to natural gas price expectations? So that when you use lower non-firm market prices, these cases also assume lower gas price escalation? This would help to explain average customer price changes given the different scenarios. Please add this clarification.

Chapter 5, page 23: Since the financial model does not include the environmental adder as a tax but only includes the added system costs of reconfiguring and operating the system to minimize the environmental tax, does this mean that PacifiCorp assumes that shareholders will absorb the cost of the tax rather than ratepayers?

Chapter 5, page 27: Second paragraph; please provide more analysis and discussion. Please include impact on total costs and emissions. I believe the impact on emissions is the opposite of the impact on price; please comment on risk. Second sentence; is this just a company *belief* or is this supported by the data? Or is the result because if load does not grow as expected, the impact of overbuilding is of consequence? Last sentence; is new resource cost close to average embedded cost of existing resources by being just above it or just below it? Is this conclusion based on assumption about gas price? Please expand this discussion. It is related to the "growth is good" concern that the Utah Commission noted in the RAMPP-3 order and requested analysis on in RAMPP-4.[5]

Chapter 5, pages 28-32: This is the section, "Findings", where we suggest you include the results of your risk analysis, least-cost analysis, and emissions analysis. If price risk is included, please discuss how average price per kWh relates to risk, i.e., who experiences the price risk, i.e., which customers, which jurisdictions. It appears that cost and emissions are elements that can be controlled to a certain degree, whereas load growth, gas prices, non-firm prices and environmental or social cost taxes are uncertainties to plan around.

Chapter 5, page 29: Gas price section; last sentence; does this imply that PacifiCorp expects the case where the link on wholesale market prices and gas prices is broken receives a zero probability? Given the extensive surplus of embedded cost, existing, and depreciating coal plants in the region and open transmission access, this may be a questionable assumption. Should probably discuss the long term consequences of the link breakage given PacifiCorp concern with average price because it looks like "price" rises.

Chapter 5, page 30: First and second paragraphs on non-firm prices; please discuss risk associated with low non-firm prices (which is a likely scenario) which causes higher "prices" and impact of this occurrence on PacifiCorp's desire to rely more heavily on the market. As the "under building" case shows, with greater reliance on the market, "price" is very sensitive to non-firm price expectations. In fact, non-firm prices have one of the bigger impacts given all scenarios, with respect to "price". Greater reliance on the market over the planning horizon certainly carries some risk. Who will bear this risk? Ratepayers? Shareholders?

Chapter 6, page 1: We suggest you delete the section on the consistency of past acquisitions

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[5] See Attachment A, page 21 and 27.

with RAMPP action plans. We are concerned that this looks like a prudency justification and may be interpreted to mean we agree with it, which may confound our ability to recommend "acknowledgment" of the RAMPP-4 Action Plan.

Chapter 6, page 15: Item c); what were the results of the program with respect to its DSR benefits? Such analysis can be conducted quite readily. Given the summer constraints, this may be a very valuable resource valued at summer peak prices.

Chapter 6, page 23: Last paragraph, first sentence; I count 20 cases. And that is just referring to average megawatts. If you look at summer peak, I believe the number of cases may increase. Factors other than load growth appear to be important, like high gas price.

Chapter 7, page 24: Last paragraph; the measure funding limits are very out of date and probably contribute to the fact that Prescriptive FinAnswer is not cost effective given new avoided costs. There are more megawatts at stake in DSR than for Qualifying Facilities yet the avoided costs are updated regularly for that tariff. Measure funding limits should be updated at least as often for the DSR tariffs. We recommend that you include updating measure funding limits on DSR tariffs to current avoided costs as an action item. Regular update should be an action item also.

RAMPP-4 Appendix: Inputs

Please add 1994 actual sales and 1995 estimated sales to sales forecasts. Also, please add table for medium low load inputs.

pc: Doug Borba, Department of Commerce
Ric Campbell, DPU
Ken Powell, DPU
Ron Burrup, DPU
Mark Flandro, DPU
Rich Collins, PSC
Mary Cleveland, CCS

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Recommended Changes to R-4 Report
Comments of Public Parties

This document lists the individual questions from each of the parties who made comments on the RAMPP-4 draft report. After each question, we have indicated how we responded, such as where in the report we added the requested information.

From RAG Meeting September 22

Explain how PacifiCorp uses IRP.
Response:
Additional text was added to the Introduction section of Chapter 1

Recheck the list of IRP requirements for page 1 of Chapter 2, and add some if needed.
Response:
Additional text adding the criteria of "least cost" was added to the Introduction section of Chapter 1

Add more on our wholesale strategy and how it impacts retail.
Response:
Additional text was added to the Perceptions - Wholesale Market section of Chapter 1

How much is PacifiCorp willing to pay to increase its knowledge of renewables?
Response:
Additional text was added to the Perceptions - Social/Environmental section of Chapter 1

Say PacifiCorp is continuing its PV and Solar II projects.
Response:
Additional text was added to the Perceptions - Social/Environmental section of Chapter 1 and to the RAMPP-4 Action Plan chapter.

Explain how the company can make IRP less static.
Response:
Additional language was added in Chapter 2, Evolution of the IRP Process

Why does PacifiCorp believe peaks are growing faster than energy?

Response:

The major change to the forecasts from RAMPP-3 to RAMPP-4 was the loss of load in Wyoming. That load had a very high load factor, around 90 percent. As a result, losing that load tended to lower energy growth more than peak growth. In addition, the company reviews the relationship of peak to energy in developing any forecast to assure that the anticipated patterns across time are consistent with known factors. If the relationships do not match with what the company expects, it makes adjustments to the peaks to keep these relationships in line with expectations. These adjustments will sometimes result in slightly differing growth rates between energy and peak.

Show the recent history of load growth, especially 1994 actuals.

Response:

The load forecast graphs in Chapter 3 -- Input Update -- have been revised to include recent actuals, and the information is also in the Appendix.

Say that PacifiCorp is a "winter peaking utility" only if considering only retail load.

Response:

Additional language explaining this in the Load Forecasts section of Chapter 3.

Add the newer wholesale transactions.

Response:

Information about the newer wholesale transactions has been added to the last section of the Inputs chapter.

Add how PacifiCorp sees competition from new technologies from other fuels.

Response:

Information on fuel cells has been added to Chapter 3.

Discussion of the Clark agreement is unclear: clarify what our kW and kWh sale amounts are and whether they are in the model.

Response:

The Clark County PUD 100 MW interim sale was modeled as 100 MW per year at 100 percent capacity factor for 1996 through 1998. The discussion of this agreement in the Input chapter has been clarified to include this information.

Provide more explanation of the economics and modeling of Gadsby repowering, both in the report and the appendix, and indicate that the cost estimates are preliminary.

Response:

Additional information on Gadsby has been added to the Report and to the Appendix.

Identify that the Gadsby repowering would add 320 MW, according to the minutes of the Dec. 9 RAG meeting.

Response:

Additional text has been added to the section of the Input chapter which discusses Gadsby.

Why is PacifiCorp assuming it will be able to continue buying gas on the short term market?

Response:

PacifiCorp based the gas price escalation in the RAMPP studies on short-term market rates because the company does not now anticipate taking any long-term position for gas supply. Therefore the escalation rate incorporated in the studies does not assume any long-term risk-related cost addition. If the financing requirements for a prospective project requires a long-term gas supply, then PacifiCorp will revisit the risk-related costs at that time.

Add a negative load growth case to the analysis.

Response:

The probable outcome of a negative load growth case is now discussed in the section Comparing RAMPP-3 and RAMPP-4 in the Results Chapter

Add an extra high load growth case to the analysis.

Response:

The probable outcome of an extra high load growth case is now discussed in the section Comparing RAMPP-3 and RAMPP-4 in the Results Chapter

Add an underbuilding case with very low non-firm prices.

Response:

The probable outcome of an underbuilding case with very low non-firm prices is now discussed in the section on the Underbuilding Cases in the Results Chapter

Summarize the conclusions/lessons learned from RAMPP-3.
Response:
Additional language has been added to the section Comparison of RAMPP-3 and RAMPP-4 in the Results chapter

Add how many dollars of TRC are equal to what percentage change in price.
Response:
The information has been added to the Presentation of Results section of the Results chapter

Add TRC analysis, especially comparing the TRC benefits of a case compared to the price benefits.
Response:
The TRC discussion has been expanded at the end of the discussion of the DSM cases and in the Risk Analysis section of the Results chapter.

What was the penalty for underbuilding, and how did the company cost that.
Response:
Additional language has been added to the section on the underbuilding cases in the Results chapter

Indicate how our cost assumptions for the underbuilding cases underestimates the attractiveness of that strategy
Response:
Additional language has been added to the section on the underbuilding cases in the Results chapter

Add more risk analysis of following vs not following TRC.
Response:
Additional discussion of TRC has been added to the DSM Cases section and to the Risk Analysis section of the Results chapter.

Talk about who will bear risks in the future (customers or shareholders)
Response:

A "risk" issue has been added to the Perceptions section of Chapter 1. The company is less concerned about who will bear the risks than that risks are balanced with rewards.

Add more risk analysis: which inputs have the most impact and thus present the most risk.

Response:

A new section on Risk Analysis has been added to the Results chapter, and these topics are included.

More discussion of environmental cases and benefits of renewable projects for the environment.

Response:

The text has been expanded in the Environmental Cases section of the Results chapter

What are our overall strategies to reduce emissions.

Response:

Text addressing the company's overall strategies to reduce emissions has been added to the discussion of the environmental cases in the Results chapter.

Separate the Action Plan chapter into one for the RAMPP-3 performance and one for the new RAMPP-4 plan.

Response:

The action plan material has been separated into two chapters, one for RAMPP-3 and one for RAMPP-4.

Say that if the world doesn't change, we'd do x (nothing but DSM), but since the world does change we plan to watch the following areas.

Response:

The additional language has been added to the RAMPP-4 Action Plan chapter

Say why we're doing DSM now even though we're over the 12 percent reserve margin.

Response:

The additional language has been added to the RAMPP-4 Action Plan chapter

Talk about the company's activities beyond the WSCC and their impact on IRP planning.

Response:
Additional language has been added in the section on RAMPP-5 plans in the RAMPP-4 Action Plan chapter

Talk about restructuring the company and its impact on IRP planning.
Response:
Additional language has been added in the section on RAMPP-5 plans in the RAMPP-4 Action Plan chapter

Land and Water Fund

Either add a case with a gas price shock after the company has already built CCCTs or consider this in RAMPP-5.
Response:
The probable outcome of a gas price shock case is now discussed in the section on Gas Prices in the Results Chapter. The cases to include in the RAMPP-5 analysis will be discussed with the public advisory group at the first few meetings for the RAMPP-5 planning cycle.

Montana Department of Environmental Quality

Table 5-2's title should be more specific and include Utility Cost.
Response:
The title has been corrected.

The report should explain in more detail that PacifiCorp is a winter peaking utility for native load, but summer peaking after wholesale sales are included.
Response:
Additional language has been added to both the Inputs chapter and the Results chapter to clarify that it is not wholesale sales that causes the peak to shift from winter to summer, it is wholesale purchases -- the company has more winter-peaking resources than it has summer-peaking resources.

The report should review the difference between RAMPP-4's starting gas price and the current gas price and discuss any significant impact that this difference may have on the results of the analysis.
Response:

The requested information has been added to the last section of the Inputs chapter.

Table 5-1 is inconsistent with the tables in Chapter 3 of the Inputs Appendix and with the Results Appendix. The values for existing generation and CCCT are inconsistent.

Response:

The tables and accompanying text have been corrected. The error was due to the treatment of the Gadsby repowering option. As discussed at the last RAG meeting, the reporting of the Gadsby Repowering on various tables causes considerable confusion. The extra 59 MW is caused by a change in the timing of the Gadsby Repowering. All of the reporting of the Gadsby Repowering has been corrected for the final RAMPP-4 report so that only incremental capacity and generation is listed as a new resource.

Table 5-2 should reference the tables in the Results Appendix that contain the rate information.

Response:

The tables in the Appendix are organized by case number so that the reader can find the information desired.

In case #1, the 109 MW summer peak purchase of gas-fired resources should be referenced to the Results Appendix.

Response:

A table in the RAMPP-4 Action Plan chapter provides information on summer peak purchases by year.

In case #4, the second paragraph should be clarified. The report text seems to contradict itself.

Response:

The language has been revised to clarify the impact of each season's reserve margin requirements.

The level of DSM in the base case is inconsistently referred to when making comparisons to cases #71, 72, and 73. The level of DSM selected in case #71 is referred to as being 539 MW; this is inconsistent with the value in Table 5-1.

Response:

The numbers have been corrected.

The discussion of TRC should be expanded throughout the Results discussion.

Response:

The TRC discussion has been expanded, the reader can find it at the end of the discussion of the DSM cases and in the Risk Analysis section of the Results chapter.

In case #5, the report should discuss why the 150 MW turbine upgrade causes a 209 MW reduction in existing generation under winter peak capacity.

Response:

As discussed at the last RAG meeting, the reporting of the Gadsby Repowering on various tables causes considerable confusion. The extra 59 MW is caused by a change in the timing of the Gadsby Repowering. All of the reporting of the Gadsby Repowering has been corrected for the final RAMPP-4 report so that only incremental capacity and generation is listed as a new resource.

In case #6, the report should discuss why the 474 MW Hermiston plant causes a 552 MW reduction in existing generation under winter peak capacity.

Response:

As discussed at the last RAG meeting, the reporting of the Gadsby Repowering on various tables causes considerable confusion. The extra 59 MW is caused by a change in the timing of the Gadsby Repowering. All of the reporting of the Gadsby Repowering has been corrected for the final RAMPP-4 report so that only incremental capacity and generation is listed as a new resource.

The amount of gas-fired and wind resources selected in case #72 and in case #73 is inconsistent with Table 5-1 and with the Results Appendix.

Response:

The text has been corrected.

The action plan should include a section that is explicit in how it meets different objectives (shareholder, customer, societal, etc.).

Response:

The company believes the action plan meets customer objectives of low prices and reliable service, shareholder objectives of increased earnings, and societal objectives of emissions control. However, an action plan which calls for only a level of DSM activity agreed to by the public advisory group and the company does not offer much material to allow for an explicit discussion of how it meets each of these objectives.

The report should address what load level causes the need for summer peak purchases, and it should explicitly state that summer peak purchases are the least cost peaking resources until the year 2003.

Response:

The section of the RAMPP-4 Action Plan chapter dealing with peaking now states that the system has more winter-peaking resources than summer-peaking resources, causing a need for summer-peaking resources sooner, and that a purchase is the least-cost choice to meet summer-only peaking needs in 2002.

The second paragraph under gas-fired baseload resources states the model selects 2221 MW instead of 2251 from Table 5-1.

Response:

The text has been corrected.

The report should explicitly state that under the medium-high load growth case, baseload resources are required by the year 2000, and because of the four-year lead time on gas-fired resources, an action plan decision may be required as early as 1996.

Response:

The Benchmarks section of the Action Plan chapter now includes the requested information.

Graphs 6-5 and 6-7 should be titled graphs and not tables. The subtitle in Graph 6-7 should either be winter MW or the graph should be corrected using the correct summer peak capacity values.

Response:

The titles have been corrected.

The RAMPP-4 report should reference specific pages in the RAMPP-3 document when discussing it.

Response:

The RAMPP-3 report contains an index at the back of the volume for the reader to use to find desired information.

All tables and graphs in the RAMPP-4 report and appendices should be labeled with units (e.g. MWhs).

Response:

The tables and graphs have been corrected.

If only part of an appendix table is included in the report, these tables should reference the relevant appendix tables.

Response:

The tables in the report are generally independent of the tables in the appendix.

The report should include a section on the potential benefits, costs, and risks of company transactions that were not included in the model runs (e.g. the Columbia Falls and Clark County contracts) addressing how much sooner additional baseload resources are needed and the potential price impacts from these transactions given varying levels of load growth. The specifics of these agreements should be included in the discussion.

Response:

The last section of the Inputs chapter includes a discussion of recent contracts. Non-traditional transactions are one of the reasons the company has proposed an alternative form of regulation in Oregon: these transactions are driven by market forces, they won't necessarily require new resources, but they are more risky from a supply-side point of view because the company will be looking to the market to help meet resource needs for these transactions. If the company takes on these risks for its shareholders, then the shareholders should receive the benefits.

The appendix should show how the load forecast changed by state between the two RAMPP processes.

Response:

Such a table has been added to the Appendix.

Northwest Power Planning Council

The document should be more specific regarding market assumptions. What is the estimated size of the wholesale market and its expected duration? What price behavior over time is assumed? Please explain your assumption of prices leveling across seasons and geographic areas in view of the continuing regional seasonality of load and the possibility of distance-based rates.

Response:

The requested information has been added to the Non-Firm Market section of the Inputs chapter.

Fifty years as the depreciation life for all supply side resources does not seem justifiable for thermal power plants, cogeneration, and wind. Twenty to thirty years seems more realistic.

Response:

When developing the economic carrying charge three 'lives' are considered, the depreciation life, the units useful life and the MACRS tax life. The following table shows these lives.

	Depreciation Life	Useful Life	MACRS Tax Life
Coal Plants	45	50	20
Combined Cycle	35	50	20
Cogeneration	35	50	20
Geothermal	30	50	20
Hydro	50	50	20
Simple Cycle	30	50	15
Wind	20	50	7

No information or analysis of hydropower efficiency improvement potential and relicensing issues is provided in the draft report.

Response:

Additional information has been added to the Inputs chapter to clarify the company's activities on its hydro units.

Please incorporate the Chapter 4 descriptions of the model runs with the results in Chapter 5.

Response:

The two chapters have been combined.

Please include Table 5-16 at the front of the chapter, with descriptions of the effect on net present value so that readers can see financial results, emissions and net present value at the same time.

Response:

The tables showing results for all of the cases in terms of financial results and emissions have been moved to the front of the Results chapter.

Put the DSM RAMPP-3 performance detail in the Appendix.

Response:

The material has been moved to a separate chapter in the Report on the RAMPP-3 action plan.

The final report should reaffirm the company's intent to continue support for the Northwest Regional Solar Monitoring Network.

Response:

This item has been added to the action plan.

The final report should reaffirm the company's continuing support for the Oregon State University Wind Research Cooperative. The company may wish to engage the Wind Research Cooperative in designing a research agenda for its wind projects.

Response:

This item has been added to the action plan.

We urge the company to ensure that research programs are implemented to maximize the value of the Foote Creek and Columbia Hills wind projects. Topics of value include: documentation of licensing experience; environmental and physical development issues and their resolution; seasonality, shear, turbulence, inter-annual variation and other wind resource characteristics; electrical integration experience; and project performance and operation and maintenance experience. The company may also wish to consider the installation of a long-term wind resource monitoring station at Foote Creek.

Response:

By contract for the Foote Creek and Columbia Hills projects, the developer, Kenetech, was responsible for licensing, including environmental and physical development issues and their resolution. Kenetech is also responsible for evaluating shear and turbulence, installing wind monitoring equipment, and the operation and maintenance costs. The company will have wind data and kWh output data from the projects, as well as experience with electrical integration. This information can be made available to parties wishing to do their own analysis.

The company should consider expanding its photovoltaic program to identify and assist in the development of cost-effective niche applications.

Response:

PacifiCorp is actively exploring the means of profitably meeting the needs of customers for photovoltaic generation in special applications where it is economic. Such services are currently being provided by a number of contractors and technology developers in very competitive markets. Therefore, any business initiative by the company would be as an unregulated business, independent of regulated distribution operations. The last section of the Inputs chapter contains a brief discussion of PacifiCorp's newest subsidiary, EnergyWorks.

The company could ensure that a market, at competitive prices, is available for biomass projects and offer wheeling services at competitive rates, credit for distributed generation benefits, and other measures to facilitate the development of these projects.

Response:

PacifiCorp does not believe it is in the best interests of customers or shareholders to subsidize any technology. Biomass will be afforded the same competitive market prices as any other generating project.

The DSM action item should be revised to incorporate a balance between least cost planning and the competitive utility environment. The level selected was least cost, considering cost, financial and price impacts.

Response:

The level of DSM determined to be cost effective was arrived at through discussions with the public advisory group. It is the amount the model selected when DSM costs were artificially lowered by 15 percent.

The company should make a stronger commitment across all sectors and end uses to work with multiple parties to bring energy efficient products to markets. A clear indication should be given in the action plan that PacifiCorp will be a willing partner in the investigation of market transformation efforts and follow through if the investigations prove fruitful.

Response:

PacifiCorp is and will continue to be a key player in the transformation of cost-effective energy efficiency markets. The company's commitment to expansion of the compact fluorescent market is but one indication of an on-going commitment.

It is not clear in the document if the RAMPP-4 actions completely supersede or simply add to the RAMPP-3 action plan. It appears that PacifiCorp is continuing a number of items in the RAMPP-3 plan, but has not mentioned them in RAMPP-4. Please make sure to include at least the following on-going items in the RAMPP-4 action items:

continue small-scale carbon offset projects, continue evaluation of cost-effectiveness and performance of wind projects, continue to participate in Solar II, continue to monitor performance of solar PV projects and publish the results, continue participation in Northwest Regional Solar Radiation Data Monitoring Project, continue to support OSU Wind Research Cooperative.

Response:

Additional information on the company's participation in the OSU Wind Cooperative and the NW Regional Solar Radiation Data Monitoring Project has been added to the RAMPP-3 action plan chapter. Several of the requested items have also been added to the RAMPP-4 action plan.

The report's statement that government actions to control greenhouse gas production is unlikely for the next ten years appears optimistic. It would be desirable to include an action item to monitor global climate change research findings. It would be prudent to revise the proposed global warming benchmark to turn not upon passage of a federal tax or controls, but upon scientific or international governmental agreements that are likely to precede congressional action resulting in taxes or controls.

Response:

The company believes its benchmarks should reflect changes that would impact the company's costs or resource situation. Therefore, the environmental benchmark will continue to turn on passage of a federal tax or control. An item has been added to the action plan to monitor global climate science.

How will Phase II SO2 control requirements be met for Centralia? What is the situation regarding nitrogen oxide emissions and alleged impact on Mt. Rainier National Park? To what extent will rail haul coal be substituted for local coal? What is the potential for efficiency improvements or repowering of the plant?

Response:

Based on a state of Washington SWAPCA (Southwest Air Pollution Control Authority) RACT (Reasonably Available Control Technology) determination for SO2 emissions from Centralia, emissions will be substantially reduced. The plant will be scrubbing 50 percent of the SO2 from each unit or switching fuel. Under the Acid Rain Program Phase II, some SO2 allowances will be purchased to meet the SO2 allowance allocation for Centralia of 39,078 tons/year. PacifiCorp's share will come from its Phase II surplus. The National Park Service has not expressed concerns about nitrogen oxide emissions from Centralia. PacifiCorp has committed to participate in agency and industry groups addressing regional visibility issues in Washington state. In the next five years, the company anticipates that 20 percent or less of Centralia's coal will be brought in by rail. PacifiCorp, as the operator of the plant, is always looking for ways to improve its efficiency. Even with a considerable investment, efficiency gains of only a few percent are possible unless the units are repowered. The cost of repowering is not competitive with other options to reduce emissions or build or buy new generating resources.

The linkage between lower penetration rates and a broader menu of programs in the early years needs more explanation

Response:

Additional language was added to the DSM section of the Inputs chapter.

Oregon Department of Energy

For EFSC siting the RAMPP-4 action plan does not call for siting or acquisition of new generation to meet summer peaking or baseload needs, if conditions change and we need to site a plant in Oregon to serve retail loads, to demonstrate need we could submit an amended plan as part of an EFSC site certificate application or we could submit an amendment to RAMPP-4 to the OPUC for acknowledgment concurrently with the EFSC application. If we want to retain this option, the report should discuss how the PUC process might work.

Response:

The company does not now anticipate it will be siting a plant in Oregon during the action plan period. However, if conditions change and the company identifies a need to site a plant in Oregon, it would discuss with Staff which of the two choices would be best under the circumstances that existed at the time. The company believes the PUC should determine how its own process might work.

RAMPP-5 should explicitly examine the distribution of risk between the wholesale and retail parts of the business.

Response:

This item has been added to the discussion of RAMPP-5 improvements.

RAMPP-5 should examine whether transmission capacity will be adequate for purchases made to meet retail needs.

Response:

This item has been added to the discussion of RAMPP-5 improvements.

Oregon Public Utility Commission

Add a section after the Perceptions section of Chapter 1 discussing the implications for resource planning. This could include the need for flexibility, which factors influenced prices most (load growth, gas prices, non-firm prices, renewable costs, governmental environmental regulations), and changes in these will cause re-examination of action plan.

Response:

The beginning section of Chapter 1 now includes a brief discussion of the need for flexibility. The Risk Analysis section of the Results chapter reviews which factors influenced prices most.

Add a summary of the major findings

Response:

As with RAMPP-3, the company has prepared an Executive Summary document for RAMPP-4, which will be provided to all recipients of the RAMPP-4 report.

Move the section "Public Advisory Process" to the end of Chapter 1.

Response:

This section was moved to Chapter 2.

Competition: The PGE/Canby deal is an example of competition bumping up against BPA's market power, not an example of competition working.

Response:

This example was removed from the report.

Change wording under "Wholesale Market as a Resource". (OPUC comment #3 under Chapter 1)

Response:

The company adopted the "can fluctuate significantly" suggestion, but not the others, for the other changes would alter the meaning PacifiCorp intended.

Changes to IRP: clarify whether PacifiCorp wants to not disclose confidential info, or does the company want to disclose it under a protective order

Response:

Additional language was added in Chapter 2, Evolution of the IRP Process.

PacifiCorp's response to the OPUC RAMPP-3 comment #3 (regarding the effect of the company's wholesale marketing strategies on its supply-side resource acquisition targets) is not adequate, it should be expanded and supported.

Response:

A new section on Risk Analysis has been added to the Results chapter which addresses this issue.

The section on gas prices needs some clarification. Is PacifiCorp saying that non-firm sales revenues (that PacifiCorp credits to rates) offset higher gas fuel costs when gas prices rise?

Response:

Clarifying language has been added to this section of the Results chapter

This plan does not adequately address the issue of relying upon the short-term non-firm market instead of building or buying other resources. The underbuilding cases need to clarify what they represent.

Response:

Additional text has been added clarifying that the company perhaps overstated the risk of underbuilding, by overstating the cost of replacement power.

Compare total system emissions and levels of CO_2 that the carbon offset programs mitigate.

Response:

This information has been added to the RAMPP-3 Action Plan chapter performance report.

Adding a specific goal and deadline to appropriate (perhaps not all) action items would tighten up the plan considerably.

Response:

The DSM item in the action plan, the only one which calls for specific resource acquisition amounts, includes dates. The other action items tend to call for monitoring and evaluating market conditions and opportunities. Such actions do not lend themselves to timelines.

Wording change to RAMPP-4 Action item #5)a): Replace the second sentence (re the wind projects) with "Once these projects are operating, evaluate performance and cost effectiveness."

Response:

The suggested wording has been added.

Can PacifiCorp support the statement that "postponing resource decisions is likely to lead to lower-cost opportunities" with an example from the model runs?

Response:

As now stated in the report, the conclusion that postponing resource decisions is likely to lead to lower-cost opportunities is based on the company's perception of the market.

Does PacifiCorp consider a gas-fired resource cost of 30 mills/kWh a threshold price for whether or not renewables are viable alternatives?

Response:

As now indicated in the Benchmarks section of the Action Plan chapter, the company believes that if renewable resources could achieve costs that are within 10 percent of the cost of competing gas-fired resources, that would warrant a new look at the action plan.

Add an item to the action plan to do resource option analysis in RAMPP-5.

Response:

This item has been added to the discussion of RAMPP-5 improvements.

Expand the Benchmarks section. How were the thresholds established? Do the thresholds drive prices unacceptably high or create dangerous resource deficits? What prices are unacceptably high or what resource deficits are dangerous? Describe what actions might be taken if one of the factors exceeds these benchmark levels.

Response:

The Benchmarks section has been expanded to explain the company's thinking on determining the benchmarks. The thresholds may not drive prices unacceptably high or create dangerous resource deficits: the intent is to have signposts that would identify changes that call for analysis and evaluation before they reached unacceptable or dangerous points.

Is there a way to avoid the APS SCCT for a longer term because of the WSCC's surplus? If so, how long?

Response:

Language has been added to the Inputs chapter clarifying the company's constraints on changing the timing of the APS CTs.

RAMPP-5 should include more option analysis.

Response:

This item has been added to the discussion of RAMPP-5 improvements.

RAMPP-5 should include more analysis and discussion of relying short-term vs longer term contracts for power from the market

Response:

This item has been added to the discussion of RAMPP-5 improvements.

Chapter 6: When will data for residential customer power use be available? How will it be used?

Response:

Additional text has been added to item 6) f) of the RAMPP-3 action plan performance information.

Utah Committee of Consumer Services

The report is silent on competition from other fuels, such as new gas technologies for the paper industry, natural gas fireplaces.

Response:

New technologies may have the effect of reducing load growth. The medium-low load forecast incorporates this possibility.

Is the Wyoming load loss now greater than expected, now about 160 MW?

Response:

The loss of load in Western Wyoming which caused most of the change in the forecasts from RAMPP-3 to RAMPP-4 are not expected to be any greater than originally determined. The load is still expected to decline about 160 MW. The uncertainty that remains is exactly when the loss will occur. From all indications it may occur more quickly than earlier predicted.

Clarify whether RAMPP-4 includes the Clark Agreement for Storage and Integration Service.

Response:

The clarification has been added to the discussion of the Clark agreements in the Inputs chapter.

Clarify whether, for the Clark Interim Sale, does PacifiCorp deliver 100 MW in each of the 3 years, or 100 MW during the 3 years.

Response:

PacifiCorp provides 100 MW in each of the three years. This has also been clarified in the report.

Errors in transmission limits between some areas.

Response:

The text has been corrected.

Identify the assumption that PacifiCorp will be able to continue buying gas using short-term contracts.

Response:

The suggested language has been added to the end of the section on gas prices.

Graph 3-17 includes Wyoming $6.50 per ton coal, but it's not in the write-up.

Response:

That line has been removed from the graph.

Change language on DSM: whether changes in the load forecast affect DSM availability. Change the last sentence of the paragraph to "RAMPP-3 assumed no DSM activity in that sector, therefore DSM availability was not affected."

Response:

The language has been changed to be more consistent with the suggestion.

Table 3-8: "sumd" should read "wind"

Response:

The table has been corrected.

Include as a change to the RAMPP-4 portfolio that solar was removed, because it was so expensive it was never selected in RAMPP-3.
Response:
The item was added to the list of RAMPP-4 changes.

Include as a change to the RAMPP-4 portfolio that Hunter was lumped with Utah coal in RAMPP-3 but in RAMPP-4 it is a separate resource.
Response:
The item was added to the list of RAMPP-4 changes.

Identify that inclusion of SCR equipment to pulverized coal would increase operating costs by 25 percent and would reduce permitting time.
Response:
Additional text has been added to the description of coal-fired resources in the Inputs chapter.

Clarify whether development of wind in Utah would take longer, whereas on Table 3-18 Utah wind is shown available in 1998.
Response:
According to PacifiCorp engineers' original documents, wind development would require three years in Utah and two years in OWC and Wyoming. Since the company is currently involved in siting wind projects in OWC and Wyoming, the lead time is less. Table 3-18 shows a two-year lead time for Utah wind simply to be consistent with OWC and Wyoming. This had no impact on modeling results.

Table 3-18 has only two columns that provide emission rates, yet the text says that three columns do.
Response:
The word was changed from three to two.

The heat rates on Table 3-18 differ from those on the December 9 handout, perhaps the incremental and the average are reversed.
Response:
Table 3-18 shows the correct heat rates as modeled in IPM. The incremental heat rate should be less than the average heat rate when a unit is near full output.

Tables 3-19, 3-20, 3-21, and 3-22 contain data which in some cases differs from that provided on December 9 (see materials provided by UCCS)..
Response:

The referenced tables were provided early in the RAMPP-4 process, and the data were extensively updated between that time and when modeling began. These updates included gas prices and escalation rates, capital costs for generating units and transmission, annual payment factors, O&M costs, and the year of cost estimates (2000 rather than 2003).

Discuss if the cost of wind is overstated because it assumes a power line is built at full capacity.

Response:

Text has been added to the discussion of renewable resources in the Input chapter addressing this issue.

Clarify that the non-firm market price of 19 mills on-peak and 16 mills off-peak was used for both non-firm purchases and sales.

Response:

The 19 mills/kWh on-peak and 16 mills/kWh off peak were used for both non-firm purchases and sales.

Clarify that only 80 percent of the non-firm price varying with the gas escalation rate was based on the assumption that not all costs could be passed through to customers and competition with coal and nuclear producers would slow price growth.

Response:

The text now clarifies that the 80 percent was an amount arrived at by discussion with the public advisory group.

Discuss the current operating reserve requirements imposed by the PNCA, the WSCC and the ICP.

Response:

This information is included in the RAMPP-3 report.

Address in the discussion of reserve requirements that in RAMPP-3 the reserve margin contribution for wind was a function of the average generation out of the plant for the entire year, but in RAMPP-4 the average generation for the specific season was used.

Response:

Clarifying language has been added to the discussion of renewable resources in the Update chapter.

Address in the discussion that hydro contribution to reserves is based on a 50-year average.

Response:
Language has been added to the Input chapter to clarify these points.

Address in the discussion that DSM contribution is deducted prior to applying the reserve requirement percentage. Does this mean that the company can't use DSM to fulfill the reserve requirement?

Response:
DSM contribution is deducted prior to applying the reserve requirement percentage. This means that 100 MW of DSM savings at the time of the system peak will reduce the need for 112 MW of some other resource.

Discuss what the various resources contribute to the reserve margin.

Response:
This information is provided in the RAMPP-3 report.

Change the language under Case 4 with no summer data: "PacifiCorp's system is more stressed in the summer than the winter because . . . However, because the company currently has more summer peaking resources available to it." Last part should be changed.

Response:
The language in the text has been corrected.

Chapter 5, page 5, says "The winter reserve margin reached 12 percent before the summer reserve margin." Needs to be fixed.

Response:
The language in the text has been corrected.

Clarify that other model changes since RAMPP-3 include resource mix capability (enables specification of annual and cumulative limits on new resource additions by type) and wind is no longer modeled as hydro.

Response:
Information on the wind modeling change has been added to the description of the model in the Inputs chapter. The resource mix capability was not implemented in RAMPP-4 although the capability was added to the IPM computer code. The resource mix capability is the ability to constrain the selection of a given type of resource either annually or cumulatively. For example, in RAMPP-3, the model selected very large amounts of wind in the environmental adder cases. With the resource mix constraint, wind could have been constrained to 50% of all new resources, thus forcing other resources to be selected.

Since no resource was over-selected in RAMPP-4, this modeling capability was not utilized.

Clarify how RAMPP-4 handled lost opportunities.

Response:

Additional text on lost opportunities has been added to the discussion of resource bundles in the DSM section of the Inputs chapter.

Were the original DSM costs also used for financial reporting purposes in cases #13 and 14?

Response:

Yes, all three DSM sensitivities (cases #12, 13, and 14) flowed original DSM costs through to the financial model. The discussion in Chapter 6 on page 24 (referenced in this question) is about the internal rate of return (IRR) financial model, and not the revenue requirements financial model used to arrive at price estimates. As discussed in the report, the IRR model was run only once, to rank DSM projects for implementation planning.

Add more discussion of how the various bundles of DSM measures were derived.

Response:

Additional text has been added in the DSM section of the Inputs chapter describing the process of developing the bundles. In addition, the Appendix contains more information.

Address changes from RAMPP-3 to RAMPP-4 that had a significant impact on the outcome of the environmental adders cases: must run in RAMPP-3, unlimited wind in RAMPP-3. These items are discussed on page 28 but they also should be noted here.

Response:

Additional text has been added to address the differences between RAMPP-3 and RAMPP-4 that affected the outcome of the environmental adder cases.

If the company had escalated the adders and escalated the non-firm prices as well, would the results have changed?

Response:

Additional language discussing this issue has been added to the comparison of RAMPP-3 and RAMPP-4 environmental results in the Results chapter.

Say that PacifiCorp has decided to find all cost-effective alternatives to postpone and/or mitigate the need for capital expenditures to meet firm load requirements. The report concludes that the company does not have to commit capital expenditures to meet firm load requirements.

Response:

Additional language has been added to the text at the beginning of the explanation of development of the Action Plan.

Define power cost savings in the financial analysis for DSM.

Response:

Additional language has been added defining the term.

Detailed items on performance on RAMPP-3 DSM action plan.

Response:

The corrections needed have been entered into the chapter on the RAMPP-3 action plan performance.

Utah Division of Public Utilities

The section on transmission states that "For comparability to be successful, all transmission owners will have to provide open, competitively priced transmission services." What is meant by "competitively priced transmission services?" Won't transmission continue to be price regulated by FERC?

Response:

Clarifying language has been added to the text in Chapter 1 dealing with expected changes in transmission.

If the company recommends that IRP makes sense for the non-competitive, regulated part of the business, why should the time horizon be shortened?

Response:

The company has changed the section of the report dealing with changes to IRP to focus on ways it could evolve. The discussion now addresses possible ways IRP could change as the industry changes.

Please add 1994 actual sales and 1995 estimated sales to the sales forecasts in the Appendix. Also, please add a table for medium-low load.

Response:

The graphs have been revised to include recent actuals, and the information is also in the Appendix. The company does not have the raw data for the medium-low load forecast by state. Instead, the Appendix now contains a table for medium-low load by geographic area.

Please provide more specific detail in what occurred for each state in developing the new load forecast. Please provide full discussion of why alternative #1 was selected when alternative #3 was the most correct approach. What was the difficulty in using alternative #3? Please provide some explanation of why new load forecasts were not used and how this could impact RAMPP-4 conclusions.

Response:

Additional text has been added to the discussion of the forecast methods for RAMPP-4 explaining the company's decision to use alternative #1.

Should the numbers in Table 3-2 be negative? Or should some of the numbers be negative? The table shows the differences in energy, what were the differences on a winter and summer peak basis?

Response:

The numbers should not be negative because the RAMPP-3 amounts were larger than the RAMPP-4 amounts. The company does not have the information necessary to develop the differences for the winter and summer peaks for table 3-2. When considering updating the forecasts the company did the entire review of needed changes using the energy forecasts. After deciding on an alternative and preparing the forecasts, system summer and winter peaks could be developed. However, the impact on the peaks would be small because there was no reallocation of energy across the months which would have changed the peaks. Also the load factor is relatively constant. Therefore the impact on the peaks would have been consistent with the change in the energy.

Please clarify that the planning period peak that triggers resource additions includes existing firm wholesale sales.

Response:

Additional language has been added to both the Inputs chapter and the Results chapter to clarify that it is not wholesale sales that causes the peak to shift from winter to summer, it is wholesale purchases.

The costs for Gadsby in Table 3-19 (sic) do not match the costs in Table 3-20. Table 3-29 shows a capacity cost of $827/kW and Table 3-20 shows $467.

Response:

The $827 is the incremental cost of capacity and the $467 is the average cost including the existing capacity. For consistency, Table 3-20 has been revised to the $827/kW.

The discussion of refurbishment expenditures is misleading. If this is the cost required to keep this amount of MW in the system, it is an O&M item and should be counted in the cost of the system. If these expenditures increase the number of MW available, then you would divide the cost by the incremental increase in MW.

Response:

Additional language has been added to the discussion of refurbishment of the existing coal plants to clarify that this was information provided in response to a request in RAMPP-3.

The text states that PacifiCorp has enough transmission capacity in each geographic area it serves to meet local load requirements. What is the time period assumed?

Response:

Additional text has been added to the transmission section of the Inputs chapter clarifying the financial assumptions included about expanding the transmission system.

The text states that ". . . usually a path with a large load at the sending end has a larger capability than one with a large load at the receiving end." Is this right? The pattern looked opposite to this.

Response:

The text now clarifies that the map shows only PacifiCorp's share of contract rights.

The numbers in the text on page 5 first paragraph do not all correspond to the numbers shown in Map 3-1.

Response:

The text has been corrected.

Were indirect costs included in RAMPP-3, or is this new in RAMPP-4?

Response:

Both RAMPP-3 and RAMPP-4 included the indirect costs of all supply-side resources, and the modeling in both cycles treated such costs in exactly the same way.

Please clarify what the 4 percent penetration rate is of: is it technical kWh potential, number of buildings, square feet?

Response:

The 4 percent penetration rate is applied to the technical potential.

The company should count as lost opportunity resources new and expanding industrial facilities. Any process or facility changes in an existing industrial plant is a window of opportunity to pursue efficiency that is on the customer's terms.

Response:

Additional text has been added to the DSM section of Chapter 3 to clarify the company's treatment of industrial DSM.

The numbers in the mid-section of Table 3-10 don't add up.

Response:

The table has been corrected.

Please state how levelized mills/kWh converts real levelized cost into mills/kWh. The explanation of the formula to calculate mills/kWh is confusing.

Response:

An example has been added to the text.

Does the company still believe that 19 mills on-peak and 16 mills off-peak are reasonable estimates of the longer-run price structure of the wholesale market? Please discuss the conclusions the company draws from any change in that market.

Response:

Current estimates for the key inputs are provided in the last section of the Update chapter. Current estimates are slightly lower than those used in the analyses. The text addresses conclusions from the change.

Did the company run a case without Hermiston and low gas prices? This would be a useful additional case.

Response:

The company completed this run, discussed it with case #7, and added its results to the Appendix.

Please clarify that total requirements peak in the summer and that this is the basis upon which resources are added.

Response:

Additional language has been added to both the Inputs chapter and the Results chapter to clarify that it is not wholesale sales that causes the peak to shift from winter to summer, it is wholesale purchases.

Please provide more analysis and discussion comparing RAMPP-3 results to the RAMPP-4 results, including the impact on total costs and emissions.

Response:

More discussion has been added addressing RAMPP-3 to RAMPP-4 comparisons, including the area of emissions.

Is new resource cost close to average embedded cost of existing resources by being just above it or just below it? Is this conclusion based on assumptions about gas prices? Please expand this discussion.

Response:

The company's 1994 system average cost was around 33 mills/kWh. The Gadsby Repowering is estimated at 23.3 mills/kWh and other resources are around 26.5 mills/kWh.

Please include, for Table 5-1, all assumptions that are common to all runs unless otherwise noted. For example, do all runs assume medium load and medium gas unless otherwise noted?

Response:

A table has been added to the Results chapter identifying the common assumptions for the cases, and where those assumptions are changed for particular cases.

What were the results of the Salt Lake City shade tree planting program with respect to its DSR benefits?

Response:

A report on the results of the shade tree planting in Salt Lake City has been added to the RAMPP-3 Action Plan chapter.

The report states that only four cases had higher DSM levels than the base case. The DPU finds 20 cases based on MWa. The number of cases may increase if measured by summer peak.

Response:

It is true that 21 cases had higher DSM amounts than the base case. However, only four cases had higher DSM levels than case #13, the case used for development of the amount of DSM in the action plan.

The measure funding limits are very out of date and probably contribute to the fact that Prescriptive FinAnswer is not cost effective given new avoided costs. Please include updating measure funding limits on DSR tariffs to current avoided costs as an action item. Regular update should be an action item also.

Response:

The Energy FinAnswer Prescriptive (EF 12000) program was cost-effective and selected by the model immediately. The company's policy is to update the measure funding limits as new avoided costs are filed. Future updates to the measure funding limits will more closely coincide with the filing of new avoided costs depending on the significance of the change in the company's avoided costs.

Please add TRC analysis and impact on emissions in addition to price impact analysis for the results.

Response:

The TRC discussion has been expanded, the reader can find it at the end of the discussion of the DSM cases and in the Risk Analysis section of the Results chapter. In addition, more discussion has been added addressing RAMPP-3 to RAMPP-4 comparisons, including the area of emissions.

The report needs more analysis and discussion of the trade-offs between costs, emissions, price impacts, etc.

Response:

More discussion has been added addressing TRC impacts, RAMPP-3 to RAMPP-4 comparisons, including the area of emissions.

Why were high gas prices used for the lumpy resource additions run? Did you also run a case with medium or low gas prices? If so, what were the results. These would be useful additional cases.

Response:

The case with lumpy resource additions used medium gas price escalation. The company did not run the lumpy case with high or low gas prices.

For case #34, the explanation of the impact on customer prices is confusing. The entire discussion of this case is confusing because it includes some over all conclusions as well as findings from just this case.

Response:

The discussion has been revised.

Clarify whether cases that use lower non-firm market prices also use lower gas prices.

Response:

Yes, they do. The text now includes this information.

Is the company's belief that lower load growth can lead to higher prices because the system operates less efficiently when it is not fully used based on a company belief or is it supported by the data? Or is the result because if load does not grow as expected the impact of overbuilding is of consequence?

Response:

Additional text has been added supporting the argument that the system operates more efficiently under higher load growth.

Does the company expect zero probability for a break in the link between wholesale market prices and gas prices. This may be a questionable assumption. Please discuss the long-term consequences of the link breakage given PacifiCorp's concern with average price.

Response:

Additional discussion of the gas price cases in the section on comparing result to RAMPP-3 clarifies the company's thinking on this issue.

Please add to this chapter the results of your risk analysis, least cost analysis, and emissions analysis. Please discuss how average price per kWh relates to risk, i.e., who experiences the price risk, i.e., which customers, which jurisdictions.

Response:

More discussion has been added addressing RAMPP-3 to RAMPP-4 comparisons, including the area of emissions. A Risk Analysis section was added to the Results chapter.

Additional work is needed analyzing the study results to provide risk analysis associated with various resource options.

Response:

A new section on Risk Analysis has been added to the Results chapter.

The section on transmission states that FERC actions may cause higher or lower prices. If the company increasingly relies on the wholesale market who will bear the risk of this strategy?

Response:

A risk issue has been added to the Perceptions section of Chapter 1. The company is less concerned about who will bear the risks than that risks are balanced with rewards.

Utah has a regulatory requirement to provide risk analysis and to identify who would bear the risk, ratepayers versus shareholders, given a particular strategy and likely outcome.

Response:

A new section on Risk Analysis has been added to the Results chapter. In addition, a risk issue has been added to the Perceptions section of Chapter 1. The company is less concerned about who will bear the risks than that risks are balanced with rewards.

Since the financial model does not include the environmental adder as a tax but only includes the added system costs of reconfiguring and operating the system to minimize the environmental tax, does this mean that PacifiCorp assumes that shareholders will absorb the cost of the tax rather than ratepayers?

Response:

The company is not making any assumptions about who will absorb the cost of an environmental tax.

Please delete the section on the consistency of past acquisitions with RAMPP action plans. This looks like a prudency justification and may be interpreted to mean the DPU agrees with it, which may confound the DPU's ability to recommend acknowledgment of the RAMPP-4 action plan.

Response:

This material has been moved to the chapter on the RAMPP-3 action plan performance.

Utah Public Service Commission

Correct the analysis of Gadsby so it is not so confusing. Include only the incremental power rather than the present method.

Response:

The references to Gadsby have been corrected in all of the relevant tables and in the accompanying text.

Add information indicating what percentage wholesale is of total sales. In addition, indicate what percentage industrial, commercial and residential are of retail sales.

Response:

This information is in the RAMPP-3 report.

Change the reference to economic theory to read: "According to economic theory, competition is an efficient way to organize industry when there are a large number of buyers and sellers, no barriers to entering or exiting the industry and information is readily available." The discussion should expound on competition as an efficient form of structure and identify those conditions which pertain to the electric industry at this point in time.

Response:

Some of the suggested language was added, but not the barriers portion. Many industries are competitive where there are barriers to entry because of capital requirements. The company does not believe that the rest of the recommended changes would not add to the development of the action plan or explanation of the company's decisions.

When discussing some possible consequences of the FERC NOPR, what time frame are you contemplating when you state "generally lower but possibly higher power prices?"

Response:

Additional language was added to this section of Chapter 1.

The discussion of alternative forms of regulation mentions the need for the company to accept the benefits and costs of risks in the wholesale market. It should acknowledge that some regulators feel that ratepayers have already accepted the majority of the risks for wholesale sales by allowing the company to acquire assets before native loads require them.

Response:

The company does not believe it can or should try to explain how some regulators feel.

The discussion notes that margins on wholesale power sales are in decline causing an upward pressure on retail rates if the company cannot maintain the current level of wholesale contribution. This implies that the risks of wholesale sales are on the ratepayer. The report states that the company must take on greater risk to achieve the same level of wholesale contribution. How does this jibe with the belief that ratepayers assume the risk of wholesale sales?

Response:

The company's beliefs about risk are now included in the Perceptions section of Chapter 1.

The company provided an inadequate response to the RAMPP-3 request that RAMPP-4 provide a suitable risk analysis to better explain why the action plan differs from least cost principles. What steps will the company take to comply with the Commission's order?

Response:

A Risk Analysis section was added to the Results chapter; it addresses these issues.

RAMPP-4 should analyze potential impacts on the IRP process brought about by a competitive restructuring of the electric industry. High and low load forecasts could help.

Response:

Additional discussion of this issue has been added to the section on the load forecast cases in the Results chapter. RAMPP-5 will address more industry restructuring issues.

Do the company's suggested changes in IRP need to be codified in a revised Standards and Guideline for IRP?

Response:

Additional language was added in Chapter 2, Evolution of the IRP process.

The company should put a disclaimer in the report that these load forecasts should not be used to establish Available Transmission Capacity (ATC) for FERC.

Response:

Such a disclaimer has been added to the load forecasting section of the Inputs chapter.

Are system efficiencies least cost? It would have been preferable to include them as resources for the model to choose.

Response:

Additional language has been added to the discussion of efficiencies on the existing system to clarify that the company always compares them to the most current avoided costs before making a final decision.

Clarify the difference between the refurbishments and the turbine upgrades. All of these efficiencies, upgrades and refurbishments should be modeled, so the model could choose when to implement them.

Response:

Additional language has been added to the discussion of refurbishment of the existing coal plants to clarify that this was information provided in response to a request in RAMPP-3.

Does the model choose the APS CTs or are they hardwired in? If chosen, when? If hardwired in, the report should explain the rationale for not modeling them.

Response:

Explanatory text has been added to the report in the discussion of the APS CTs.

Is PacifiCorp backing away from its past commitments for wind, in that the economics of alternative resources, i.e., gas power turbines, has changed?

Response:

As indicated in the RAMPP-4 Action Plan chapter, the company is continuing its participation in the two wind plants..

The correlation between wholesale prices and gas escalation rates needs more clarification and justification. If there is excess capacity in the regional market, then wholesale prices will be determined by the variable cost of the excess capacity, not the cost of new resources.

Response:

The report now clarifies that the 80 percent correlation was arrived at after discussion with the public advisory group.

Specify what the assumed escalation rates are for non-firm market prices.

Response:

The text now includes this information.

Case #7 without Hermiston should have been run with low gas prices. This would tell us more.

Response:

The company completed this run, discussed it with case #7, and added its results to the Appendix.

The discussion of cases #6 and #7 focuses on why Hermiston is beneficial to ratepayers. In order to draw that conclusion you need to run a case with low gas prices. Either do so or acknowledge that analysis of a low gas case is necessary before one can draw any conclusion about benefits to ratepayers.

Response:

The company completed this run, discussed it with case #7, and added its results to the Appendix.

Page 5 of chapter 5, 8th line, should "more" be replaced with "less" in front of the word summer?

Response:

The language in the text has been corrected.

Clarify that in RAMPP-3 coal-fired resources, and in RAMPP-4 gas-fired resources were the least expensive supply-side choice. See Chap 5 page 27, paragraph 4, last sentence.

Response:

The additional wording has been added.

The Findings section should center more on the effects that load growth, gas prices, etc. have on costs and how that will influence the action plan.

Response:

Since the action plan requires no supply-side acquisitions in the action-plan period, these variables would have no effect.

Does the assumption that there is a much lower wind availability affect the resource selection? Explain why the company changed this assumption.

Response:

The text in the Input chapter and in the Results chapter has been expanded to explain this issue better.

For case #11, why did the company choose not to include the assumed lower DSM costs in its financial analysis? Both methods should be done and reported.

Response:

The three DSM sensitivity cases are #12 with a 20 percent cost advantage, #13 with a 15 percent cost advantage, and #14 with a 15 percent cost disadvantage. The intent of these cases was to determine which programs and which amounts would be selected at the different cost levels. The public advisory group then used this information to arrive at the position that case #13 should be used for the action plan. Since the company would experience the original costs, not the artificially lowered costs used for model inputs, it would not be appropriate to use those artificially lowered costs in the financial model. The financial model should reflect the costs the company would actually experience.

The discussion must be expanded to include an analysis of cost impacts, in particular TRC. Any discrepancies between the two objectives, least cost and price, should be made explicit.

Response:

The TRC discussion has been expanded, the reader can find it at the end of the discussion of the DSM cases and in the Risk Analysis section of the Results chapter.

The discussion should include a section on why PacifiCorp decided to change the emphasis from TRC to price and justify your reasons for doing so.

Response:

The beginning of the Results chapter, under Presentation of Results, now includes an explanation of why the company weighted price impacts so heavily.

What about the possibility of canceling the Hermiston project? What are the replacement costs of other cogeneration? They need to be in line with current estimates, for instance the ACME project.

Response:

Canceling the Hermiston project is not an option due to load requirements and contractual obligations. As shown on the Company's RAMPP-3 load and resource balance (excluding Hermiston), at that time the company needed to acquire resources by 1996 to meet load requirements. The pertinent RAMPP-3 action plan item stated that the Company should "meet baseload requirements with the installation of 500-900 MW of cogeneration and/or combined cycle combustion turbines (CCCTs) by 2001, consistent with cost-effective criteria." When the company made the decision to participate in the Hermiston Project it was the most competitive project available.

The Hermiston project's west side location and the dispatchability, albeit limited, of the power make the project a valuable resource for the company's entire system. With an anticipated capacity factor of approximately 93 percent the project is expected to provide power for PacifiCorp's customers in the retail and wholesale market. The addition of a gas-fired cogeneration resource provides the benefit of fuel diversity to the company's system. The project's business agreements protect customers and shareholders from much of the risk associated with financing and building new generating resources, and allow the company to take advantage of a long-term fixed cost gas supply. The gas contracts allow the company to displace purchases down to a specified level without penalty and also allow the company to use a portion of the gas deliveries elsewhere on its system. The company signed a binding agreement to participate in the Hermiston project in October 1993. Construction of the project started in November 1994 with the expectation of the plant being on-line July, 1996. If the company were to back out of the agreement at this stage, it would be liable for construction costs incurred to date plus a significant level of damages.

The underbuilding cases need a more realistic estimate of non-firm market prices. Two mills above the cost of a CCCT is too low. This case should be re-run with realistically low non-firm prices, maybe 13-16 mills.

Response:

Additional text has been added clarifying that the company perhaps overstated the risk of underbuilding, by overstating the cost of replacement power.

The report should identify if the action plan deviates from least cost and then discuss why it deviates and explain the risks associated with such a deviation.

Response:

The company does not believe that the action plan deviates from least cost.

The discussion of environmental adders should be expanded. It should include some discussion of risk and strategies to mitigate the risk of future internalization of environmental externalities.

Response:

A new section on Risk Analysis has been added to the Results chapter.

If PacifiCorp expects a situation of excess power for 5-7 years and maybe 10 years or longer, why not just purchase all new capacity from the market? This should be discussed somewhere in the report.

Response:

Any strategy carries risks. The company tries to balance risks with benefits and make decisions which result in low prices for customers.

How do the results of the renewable case affect the company's investments in the Wyoming and Washington wind projects?

Response:

The company continues its participation in the two wind projects.

The analysis of the costs to reduce CO2 emissions gives a false impression of the impact of such adders. Rather than reconfiguring the system, wouldn't the company purchase CO2 offsets or emission permits?

Response:

If CO2 offsets or emission permits could be purchased to offset CO2 emissions, then they could be used to reduce costs. However, the company did not make any assumptions about conditions or prices in some future market for CO2 offsets or permits.

Remove the entire section on Consistency of Past Acquisitions with RAMPP Action Plans and put it in a separate chapter. Inclusion in this chapter makes it appear that acknowledgment of the action plan also acknowledges the discussion of consistency.

Response:

This material has been moved to the chapter on the RAMPP-3 action plan performance.

The Action Plan chapter should not end with a discussion of DSM, in fact this chapter should be before your action plan chapter.

Response:

The material on RAMPP-3 and RAMPP-4 action plans has been re-organized.

Provide an update of the Solar II project and discuss whether it will continue to run after its two year trial. If not, why not?

Response:

Additional text has been added to the reporting on Solar II performance in the RAMPP-3 Action Plan chapter.

Either delete the section on other opportunities or explain how the company drew its conclusion and specify what model runs substantiate this action plan item, especially how is this consistent with the statement that "The single most significant principle in the RAMPP-4 action plan is this: the wisdom of postponing decisions."

Response:

Additional text has been added to the discussion of this action plan item to better explain the company's intention.

Load forecasts for RAMPP-5 should include the possibility of loss of load and also greater wholesale loads.

Response:

This item has been added to the discussion of RAMPP-5 improvements.

The report should end with a summary or conclusion chapter to recap the major findings.

Response:

As with RAMPP-3, the company has prepared an Executive Summary document for RAMPP-4, which will be provided to all recipients of the RAMPP-4 report.

Washington State Energy Office

Add "least cost" to list of basic elements of IRP

Response:

Additional text adding the criteria of "least cost" was added to the Introduction section of Chapter 1

Explain why a peaking capacity and spinning reserve agreement with Clark has little effect on PacifiCorp's need for new resources and was not modeled.

Response:

An explanation of the company's decision to not model this agreement in RAMPP-4 has been added to the discussion of the Clark agreements in the Inputs chapter.

What assumptions does the company make concerning utility versus participant funding of DSM in its revenue requirements and price models?

Response:

Additional text has been added to the discussion of DSM in the Inputs chapter to address this issue.

If protection of customers from higher gas prices depends on the company's success in the wholesale market, what risk is the company potentially exposing to its customers. Is the company allocating the risk of this business to its retail customers by its strategy of going long and marketing excess, rather than staying short and purchasing on the short-term non-firm market?

Response:

A Risk Analysis section was added to the Results chapter which addresses these issues.

Has the company analyzed the potential for either water heater load control or irrigation load control in the Yakima area?

Response:

The company has not conducted an analysis of the load control opportunities in the Yakima area.

Change the language to read "Work with regulatory agencies . . . to make the process more valuable to utilities *and customers* operating in a competitive marketplace."

Response:

The requested language has been added.

Discuss how unbundled wholesale transactions will be modeled in future RAMPPs. We would like some comfort that the company has analyzed each such transaction to ensure it will not adversely affect retail service obligations.

Response:

This item has been added to the discussion of RAMPP-5 improvements.

On page 3 of Chap. 2, PacifiCorp says that wholesale transactions are limited to marketing excess capacity because of lumpy resources to reduce total system costs, but on page 7 the report says the company can't analyze the extent to which lumpiness affects system costs. So how can the company know is preferable to go long and market excess capacity rather than going short and purchasing on the wholesale market?

Response:

A new section on Risk Analysis has been added to the Results chapter. Also, additional material has been added to the discussion of the underbuilding cases in the Results chapter.

Resource and Market Planning Program

RAMPP - 4

APPENDIX: MODEL OUTPUT

NOVEMBER, 1995

PACIFICORP

PacifiCorp
RAMPP-4
Appendix: Model Output

Table of Contents

PacifiCorp
RAMPP-4
Appendix: Model Output

Table of Contents

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Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 1 of 8

	Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant		No DSM Allowed	DSM Costs		
							Med Gas	High Gas		Reduced by 20%	Reduced by 15%	Increased 15%
	Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load	8,807				8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485				1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM	(352)				(358)	(359)	(400)	0	(450)	(436)	(297)
4	**Total Requirements**	9,940				9,934	9,933	9,892	10,292	9,842	9,856	9,995
5	Existing Generation	10,123				9,974	9,689	9,689	10,123	10,122	10,122	10,123
6	Firm Purchases	424				424	424	424	424	424	424	424
7	New Resources											
8	Renewable	0				0	0	0	0	0	0	0
9	Cogeneration	363				431	715	966	683	371	382	351
10	Combined Cycle CT	222				297	297	0	297	105	110	297
11	Coal	0				0	0	0	0	0	0	0
12	Transmission	0				0	0	0	0	0	0	0
13	Peaking Resources	0				0	0	0	0	0	0	0
14	**Total Resources**	11,132				11,126	11,125	11,079	11,527	11,022	11,038	11,195
15	Reserves	1,192				1,192	1,192	1,187	1,235	1,180	1,182	1,200
16	Reserve Margin (RM) (%)	12.0				12.0	12.0	12.0	12.0	12.0	12.0	12.0
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load	9,104	9,273	9,273	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	1,195	1,195	995	995	995	995	995	995	995	995
19	less DSM	(446)	(608)	(616)	(445)	(453)	(455)	(487)	0	(529)	(515)	(387)
20	**Total Requirements**	9,653	9,860	9,852	9,654	9,646	9,645	9,612	10,099	9,570	9,584	9,712
21	Existing Generation	10,162	10,054	10,054	10,161	10,012	9,669	9,669	10,161	10,161	10,161	10,161
22	Firm Purchases	319	317	317	319	319	319	319	319	319	319	319
23	New Resources											
24	Renewable	0	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	387	0	0	104	458	760	1,028	726	395	406	373
26	Combined Cycle CT	248	0	0	229	331	331	0	331	117	123	331
27	Coal	0	721	698	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	247	262	0	0	0	0	0	0	0	0
30	**Total Resources**	11,115	11,340	11,331	10,813	11,120	11,079	11,016	11,538	10,992	11,009	11,184
31	Reserves	1,462	1,480	1,479	1,159	1,474	1,435	1,404	1,439	1,422	1,426	1,472
32	Reserve Margin (RM) (%)	15.1	15.0	15.0	12.0	15.3	14.9	14.6	14.2	14.9	14.9	15.2

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 2 of 8

	Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant		No DSM Allowed	DSM Costs		
										Reduced by		Increased
							Med Gas	High Gas		20%	15%	15%
	Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Annual Energy in Year 2005 (MWa)											
1	Native Load	6,463	6,634	6,634	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	376	383	305	305	305	299	305	305	305	305
3	Firm Sales	1,266	1,410	1,410	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	512	507	691	957	914	931	1,020	884	889	937
5	less DSM	(244)	(348)	(351)	(200)	(250)	(251)	(272)	0	(299)	(291)	(196)
6	**Total Requirements**	8,710	8,584	8,583	8,524	8,741	8,696	8,686	9,053	8,618	8,631	8,775
7	Existing Generation	7,768	7,473	7,476	7,809	7,672	7,351	7,313	7,760	7,746	7,746	7,787
8	Firm Purchases	400	364	364	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	47	44	46	0	5	22	0	18	15	4
10	New Resources											
11	Renewable	0	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	0	0	97	426	707	951	676	367	378	347
13	Combined Cycle CT	183	0	0	172	242	233	0	217	88	92	237
14	Coal	0	661	639	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	55	59	0	0	0	0	0	0	0	0
17	**Total Resources**	8,710	8,599	8,582	8,524	8,741	8,696	8,686	9,053	8,618	8,631	8,775
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO_2	55,189			55,577	54,430	55,104	55,413	#N/A	55,094	55,118	55,315
19	NO_x	125			125	123	125	126	#N/A	125	125	125
	Financial Results with End Effects to 2045								+ 911	+ 4		
20	50-year Utility Cost											
21	**NPV at 8.6% (million $)**	42,560			42,284	42,610	43,273	43,620	43,471	42,564	42,571	42,578
22	**Real Levelized (mills/kWh)**	42.55			41.98	42.64	43.31	43.86	41.52	43.00	42.96	42.17
									+ 481	+ 269	+ 235	
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	42,990			42,610	43,052	43,716	44,158	43,471	43,259	43,225	42,905
25	Real Levelized (mills/kWh)	41.07			40.70	41.12	41.76	42.18	41.52	41.32	41.29	40.98
25	**IPM Obj Function (millions $)**	19,164			18,930	19,390	19,485	19,579	19,620	18,923	18,998	19,307
									+ 456			

(A) Case 2 and 3 are RAMPP-3 models. Since these models did not have a 2005 run year, 2003 is presented. Therefore these two cases should only be compared against each other.

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 3 of 8

	Case Name	Base Case Study	Load Growth Rate		Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices		Lumped Resource Additions	Non-Firm Prices	
			Medium Low	Medium High			High	Med		Lower by 25%	Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Summer Peak Capacity in Year 2005 (MW)										
1	Native Load	8,807	7,597	10,117	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM	(352)	(112)	(505)	(303)	(392)	(400)	(435)	(367)	(347)	(355)
4	**Total Requirements**	**9,940**	**8,970**	**11,097**	**9,989**	**9,900**	**9,892**	**9,857**	**9,925**	**9,945**	**9,937**
5	Existing Generation	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123
6	Firm Purchases	424	424	424	424	424	424	424	424	424	424
7	New Resources										
8	Renewable	0	0	0	0	0	0	0	0	0	0
9	Cogeneration	363	0	1,584	344	541	532	493	301	294	340
10	Combined Cycle CT	222	0	297	297	0	0	0	297	297	243
11	Coal	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	0	0	0	0	0	0
14	**Total Resources**	**11,132**	**10,547**	**12,429**	**11,188**	**11,088**	**11,079**	**11,040**	**11,145**	**11,138**	**11,130**
15	Reserves	1,192	1,577	1,332	1,199	1,188	1,187	1,183	1,220	1,194	1,193
16	Reserve Margin (RM) (%)	12.0	17.6	12.0	12.0	12.0	12.0	12.0	12.3	12.0	12.0
	Winter Peak Capacity in Year 2005 (MW)										
17	Native Load	9,104	7,895	10,473	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	995	995	995	995	995	995	995	995	995
19	less DSM	(446)	(131)	(619)	(394)	(482)	(487)	(514)	(460)	(438)	(450)
20	**Total Requirements**	**9,653**	**8,759**	**10,849**	**9,705**	**9,617**	**9,612**	**9,585**	**9,640**	**9,661**	**9,649**
21	Existing Generation	10,162	10,161	10,161	10,161	10,161	10,161	10,161	10,161	10,161	10,161
22	Firm Purchases	319	319	319	319	319	319	319	319	319	319
23	New Resources										
24	Renewable	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	387	0	1,685	366	576	566	524	320	313	362
26	Combined Cycle CT	248	0	331	331	0	0	0	331	331	271
27	Coal	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	0	0	0	0	0	0
30	**Total Resources**	**11,115**	**10,480**	**12,497**	**11,177**	**11,056**	**11,046**	**11,004**	**11,131**	**11,124**	**11,113**
31	Reserves	1,462	1,721	1,647	1,472	1,438	1,434	1,419	1,492	1,463	1,464
32	Reserve Margin (RM) (%)	15.1	19.7	15.2	15.2	15.0	14.9	14.8	15.5	15.1	15.2

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 4 of 8

	Case Name	Base Case Study	Load Growth Rate Medium Low	Load Growth Rate Medium High	Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices High	High Gas Price Non-firm Prices Med	Lumped Resource Additions	Non-Firm Prices Lower by 25%	Non-Firm Prices Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Annual Energy in Year 2005 (MWa)										
1	Native Load	6,463	5,596	7,438	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	978	1,092	860	926	927	886	939	645	991
5	less DSM	(244)	(85)	(346)	(196)	(268)	(272)	(290)	(256)	(238)	(247)
6	**Total Requirements**	8,710	8,060	9,755	8,698	8,690	8,688	8,629	8,717	8,440	8,777
7	Existing Generation	7,768	7,652	7,680	7,672	7,748	7,751	7,715	7,783	7,514	7,830
8	Firm Purchases	400	400	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	8	0	20	10	12	27	5	125	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	0	1,513	340	533	525	488	298	289	337
13	Combined Cycle CT	183	0	163	266	0	0	0	232	113	210
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	0	0	0
17	**Total Resources**	8,710	8,060	9,755	8,698	8,690	8,688	8,629	8,717	8,440	8,777
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	55,189	52,938	57,983	54,729	55,408	55,496	55,508	55,109	54,185	55,205
19	NO_x	125	124	125	123	126	127	127	125	121	125
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	42,560	38,921	47,134	42,649	41,924	42,457	43,052	42,312	43,459	41,564
22	Real Levelized (mills/kWh)	42.55	43.92	41.31	42.21	42.11	42.69	43.44	42.38	43.39	41.57
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	42,990	39,062	47,849	42,973	42,445	42,995	43,705	42,773	43,885	41,998
25	Real Levelized (mills/kWh)	41.07	43.03	39.64	41.05	40.54	41.07	41.75	40.86	41.92	40.12
25	**IPM Obj Function (millions $)**	19,164	14,895	24,484	19,113	18,860	19,098	19,791	19,175	19,990	18,337

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Page 5

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 5 of 8

		Case Name	Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
				25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	CCCT+2 25% Lower	CCCT+6 Medium	CCCT+10 25% Higher
		Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load		8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales		1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485	1,485
3	less DSM		(352)	(345)	(351)	(351)	(340)	(348)	(348)	(353)	(363)	(363)
4	**Total Requirements**		9,940	9,947	9,941	9,941	9,952	9,944	9,945	9,939	9,929	9,929
5	Existing Generation		10,123	10,123	10,123	10,122	10,123	10,122	10,122	10,123	10,123	10,123
6	Firm Purchases		424	424	424	424	424	424	424	424	424	424
7	New Resources											
8	Renewable		0	0	0	0	0	0	0	0	0	0
9	Cogeneration		363	297	364	371	470	470	470	86	150	344
10	Combined Cycle CT		222	297	223	226	130	121	169	168	102	168
11	Coal		0	0	0	0	0	0	0	0	0	0
12	Transmission		0	0	0	0	0	0	0	0	0	0
13	Peaking Resources		0	0	0	0	0	0	0	331	321	321
14	**Total Resources**		11,132	11,141	11,134	11,143	11,146	11,137	11,185	11,131	11,121	11,380
15	Reserves		1,192	1,194	1,193	1,202	1,194	1,193	1,241	1,193	1,192	1,451
16	Reserve Margin (RM) (%)		12.0	12.0	12.0	12.1	12.0	12.0	12.5	12.0	12.0	14.6
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load		9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales		995	995	995	995	995	995	995	995	995	995
19	less DSM		(446)	(435)	(444)	(447)	(430)	(441)	(442)	(444)	(458)	(460)
20	**Total Requirements**		9,653	9,664	9,655	9,652	9,670	9,658	9,657	9,655	9,641	9,640
21	Existing Generation		10,162	10,161	10,162	10,161	10,162	10,161	10,161	10,161	10,161	10,161
22	Firm Purchases		319	319	319	319	319	319	319	319	319	319
23	New Resources											
24	Renewable		0	0	0	0	0	0	0	0	0	0
25	Cogeneration		387	316	387	395	500	500	500	91	160	366
26	Combined Cycle CT		248	331	249	251	145	134	188	187	114	187
27	Coal		0	0	0	0	0	0	0	0	0	0
28	Transmission		0	0	0	0	0	0	0	0	0	0
29	Peaking Resources		0	0	0	0	0	0	0	352	342	342
30	**Total Resources**		11,115	11,127	11,116	11,127	11,125	11,115	11,169	11,110	11,096	11,375
31	Reserves		1,462	1,463	1,461	1,474	1,456	1,457	1,512	1,455	1,455	1,735
32	Reserve Margin (RM) (%)		15.1	15.1	15.1	15.3	15.1	15.1	15.7	15.1	15.1	18.0

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 6 of 8

		Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
									CCCT+2	CCCT+6	CCCT+10
	Case Name		25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher
	Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Annual Energy in Year 2005 (MWa)										
1	Native Load	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
4	Non-Firm Sales	921	638	923	994	674	919	1,011	502	695	1,009
5	less DSM	(244)	(236)	(243)	(244)	(232)	(240)	(240)	(244)	(255)	(255)
6	Total Requirements	8,710	8,435	8,713	8,784	8,475	8,712	8,804	8,291	8,473	8,787
7	Existing Generation	7,768	7,514	7,768	7,822	7,519	7,742	7,791	7,520	7,778	7,822
8	Firm Purchases	400	400	400	400	400	400	400	400	400	400
9	Non-Firm Purchases	0	148	2	0	107	6	0	204	49	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	360	261	360	368	400	465	465	85	149	341
13	Combined Cycle CT	183	113	184	194	49	100	148	68	86	149
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	13	13	75
17	Total Resources	8,710	8,435	8,713	8,784	8,475	8,712	8,804	8,291	8,473	8,787
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	55,189	54,153	55,186	55,226	54,090	55,134	55,157	54,344	55,334	55,310
19	NO_x	125	121	125	125	121	125	125	122	126	126
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	42,560	43,512	42,598	41,676	43,641	42,767	41,779	43,707	42,966	41,719
22	Real Levelized (mills/kWh)	42.55	43.43	42.58	41.64	43.53	42.73	41.74	43.68	43.03	41.79
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	42,990	43,932	43,025	42,098	44,051	43,187	42,196	44,146	43,415	42,167
25	Real Levelized (mills/kWh)	41.07	41.97	41.10	40.21	42.08	41.25	40.31	42.17	41.47	40.28
25	**IPM Obj Function (millions $)**	19,164	20,043	19,189	18,344	20,107	19,227	18,368	20,027	19,321	18,542

Note: (A) An additional 2, 6, or 10 mill/kWh was added to the CCCT cost to represent an additonal profit margin for an energy producer selling power in a sellers market.

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

	Case Name	Base Case Study	Added Transm: Test Transm Conversion	Added Transm: Bridger to OWC	Added Transm: Utah to OWC	Cheaper Renew-ables	Extend Inputs to 2045: Firm Contracts	Extend Inputs to 2045: Loads and DSM	Extend Inputs to 2045: All Inputs	Environmental Adders with CO2 Costs at $10/ton	Environmental Adders with CO2 Costs at $25/ton	Environmental Adders with CO2 Costs at $40/ton
	Case #	1	57	58	59	61	65	66	67	71	72	73
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807
2	Firm Sales	1,485	1,485	1,485	1,485	1,485	2,130	1,485	2,130	1,485	1,485	1,485
3	less DSM	(352)	(402)	(353)	(352)	(348)	(370)	(332)	(373)	(362)	(426)	(460)
4	**Total Requirements**	9,940	9,890	9,940	9,940	9,944	10,567	9,960	10,564	9,930	9,866	9,832
5	Existing Generation	10,123	10,123	10,122	10,123	10,123	10,123	10,123	10,123	10,123	10,123	10,123
6	Firm Purchases	424	424	424	424	424	692	424	692	424	424	424
7	New Resources											
8	Renewable	0	0	0	0	54	0	0	0	0	592	876
9	Cogeneration	363	233	364	363	217	723	355	720	985	1,973	1,660
10	Combined Cycle CT	222	297	222	222	120	297	254	297	297	1,889	2,532
11	Coal	0	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	200	0	0	0	0	0	0
14	**Total Resources**	11,132	11,077	11,132	11,132	11,137	11,835	11,155	11,832	11,829	15,002	15,616
15	Reserves	1,192	1,187	1,192	1,192	1,157	1,268	1,195	1,268	1,899	4,740	5,199
16	Reserve Margin (RM) (%)	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	19.1	52.0	58.8
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104	9,104
18	Firm Sales	995	995	995	995	995	1,463	995	1,463	995	995	995
19	less DSM	(446)	(487)	(445)	(446)	(439)	(459)	(427)	(462)	(462)	(509)	(537)
20	**Total Requirements**	9,653	9,612	9,654	9,653	9,660	10,108	9,672	10,105	9,637	9,590	9,562
21	Existing Generation	10,162	10,161	10,161	10,162	10,162	10,161	10,162	10,161	10,161	10,161	10,161
22	Firm Purchases	319	319	319	319	319	954	319	954	319	319	319
23	New Resources											
24	Renewable	0	0	0	0	54	0	0	0	0	712	1,166
25	Cogeneration	387	248	387	387	230	769	377	766	1,048	2,099	1,766
26	Combined Cycle CT	248	331	247	248	133	331	283	331	331	2,025	2,709
27	Coal	0	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	200	0	0	0	0	0	0
30	**Total Resources**	11,115	11,059	11,114	11,115	11,098	12,216	11,141	12,212	11,859	15,316	16,121
31	Reserves	1,462	1,447	1,461	1,462	1,438	2,107	1,469	2,107	2,222	5,726	6,559
32	Reserve Margin (RM) (%)	15.1	15.1	15.1	15.1	14.9	20.8	15.2	20.8	23.1	59.7	68.6

Comparative Results of RAMPP-4 Runs
Resource Selections by 10th year, Emissions and Financial Results

Table 4-2, Page 8 of 8

		Base	Added Transm			Cheaper	Extend Inputs to 2045			Environmental Adders with CO2 Costs at		
	Case Name	Base Case Study	Test Transm Conversion	Bridger to OWC	Utah to OWC	Cheaper Renew-ables	Firm Contracts	Loads and DSM	All Inputs	$10/ton	$25/ton	$40/ton
	Case #	1	57	58	59	61	65	66	67	71	72	73
	Annual Energy in Year 2005 (MWa)											
1	Native Load	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463	6,463
2	Pump Storage/Peak Return	305	305	305	305	305	305	305	305	305	300	305
3	Firm Sales	1,266	1,266	1,266	1,266	1,266	1,683	1,266	1,683	1,266	1,266	1,266
4	Non-Firm Sales	921	890	954	926	912	971	931	970	239	180	283
5	less DSM	(244)	(272)	(244)	(244)	(240)	(256)	(227)	(255)	(256)	(287)	(304)
6	Total Requirements	8,710	8,650	8,743	8,715	8,706	9,165	8,736	9,166	8,017	7,921	8,013
7	Existing Generation	7,768	7,785	7,787	7,768	7,739	7,724	7,776	7,726	5,892	2,453	1,998
8	Firm Purchases	400	400	400	400	400	523	400	523	400	403	403
9	Non-Firm Purchases	0	3	0	4	5	0	4	0	449	627	498
10	New Resources											
11	Renewable	0	0	0	0	51	0	0	0	0	608	956
12	Cogeneration	360	231	360	360	214	716	351	713	975	1,953	1,644
13	Combined Cycle CT	183	232	196	183	99	202	205	203	302	1,878	2,514
14	Coal	0	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	198	0	0	0	0	0	0
17	Total Resources	8,710	8,650	8,743	8,715	8,706	9,165	8,736	9,166	8,017	7,921	8,013
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO2	55,189	55,160	55,320	55,211	54,216	54,851	55,220	54,838	44,911	24,956	20,639
19	NOx	125	125	126	125	125	125	125	125	91	32	22
	Financial Results with End Effects to 2045											
20	50-year Utility Cost											
21	NPV at 8.6% (million $)	42,560	41,877	43,039	43,060	42,277	42,273	45,026	45,141	43,665	52,388	55,552
22	Real Levelized (mills/kWh)	42.55	42.12	43.03	43.05	42.19	42.35	41.29	41.53	43.74	52.84	56.16
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	42,990	42,426	43,469	43,490	42,698	42,744	45,473	45,656	44,110	53,027	56,276
25	Real Levelized (mills/kWh)	41.07	40.53	41.52	41.54	40.79	40.83	39.97	40.13	42.13	50.65	53.76
25	IPM Obj Function (millions $)	19,164	19,541	19,154	19,163	18,657	22,121	22,579	26,347	34,736	46,812	56,486

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)
Resource Selections by 10th year, Emissions and Financial Results

	Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant		No DSM Allowed	DSM Costs		
							Med Gas	High Gas		Reduced by 20%	Reduced by 15%	Increased 15%
	Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load	0				0	0	0	0	0	0	0
2	Firm Sales	0				0	0	0	0	0	0	0
3	less DSM	0				(6)	(7)	(48)	352	(98)	(84)	56
4	**Total Requirements**	0				(6)	(7)	(48)	352	(98)	(84)	56
5	Existing Generation	0				(149)	(434)	(434)	0	(0)	(0)	0
6	Firm Purchases	0				0	0	0	0	0	0	0
7	New Resources											
8	Renewable	0				0	0	0	0	0	0	0
9	Cogeneration	0				67	351	603	319	8	18	(13)
10	Combined Cycle CT	0				75	75	(222)	75	(117)	(112)	75
11	Coal	0				0	0	0	0	0	0	0
12	Transmission	0				0	0	0	0	0	0	0
13	Peaking Resources	0				0	0	0	0	0	0	0
14	**Total Resources**	0				(6)	(7)	(53)	395	(110)	(94)	63
15	Reserves	0				(0)	(0)	(5)	43	(12)	(10)	7
16	Reserve Margin (RM) (%)	0.0				0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load	0			0	0	0	0	0	0	0	0
18	Firm Sales	0			0	0	0	0	0	0	0	0
19	less DSM	0			1	(7)	(9)	(41)	446	(83)	(69)	59
20	**Total Requirements**	0			1	(7)	(9)	(41)	446	(83)	(69)	59
21	Existing Generation	0			(0)	(150)	(493)	(493)	(1)	(0)	(0)	(1)
22	Firm Purchases	0			0	0	0	0	0	0	0	0
23	New Resources											
24	Renewable	0			0	0	0	0	0	0	0	0
25	Cogeneration	0			(282)	72	374	641	340	8	19	(13)
26	Combined Cycle CT	0			(19)	84	84	(248)	84	(130)	(125)	84
27	Coal	0			0	0	0	0	0	0	0	0
28	Transmission	0			0	0	0	0	0	0	0	0
29	Peaking Resources	0			0	0	0	0	0	0	0	0
30	**Total Resources**	0			(302)	6	(35)	(99)	423	(122)	(106)	70
31	Reserves	0			(303)	13	(27)	(58)	(23)	(39)	(36)	11
32	Reserve Margin (RM) (%)	0.0			(3.1)	0.1	(0.3)	(0.5)	(0.9)	(0.3)	(0.3)	0.0

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Comparative Results of RAMPP-4 Runs (Case Results less Case 1)
Resource Selections by 10th year, Emissions and Financial Results

#	Case Name	Base Case Study	R-3 Data using R-3 Code	R-3 Data using R-4 Code	No Summer Season	No Turbine Upgrades	No Hermiston Plant: Med Gas	No Hermiston Plant: High Gas	No DSM Allowed	DSM Costs Reduced by 20%	DSM Costs Reduced by 15%	DSM Costs Increased 15%
	Case #	1	2 (A)	3 (A)	4	5	6	7	11	12	13	14
	Annual Energy in Year 2005 (MWa)											
1	Native Load	0			0	0	0	0	0	0	0	0
2	Pump Storage/Peak Return	0			0	0	0	(6)	0	0	0	0
3	Firm Sales	0			0	0	0	0	0	0	0	0
4	Non-Firm Sales	0			(230)	36	(7)	10	99	(37)	(33)	16
5	less DSM	0			44	(6)	(7)	(28)	244	(55)	(47)	48
6	**Total Requirements**	0			(186)	30	(14)	(25)	343	(92)	(79)	65
7	Existing Generation	0			41	(96)	(417)	(455)	(8)	(22)	(22)	19
8	Firm Purchases	0			0	0	0	0	0	0	0	0
9	Non-Firm Purchases	0			46	0	5	22	0	18	15	4
10	New Resources											
11	Renewable	0			0	0	0	0	0	0	0	0
12	Cogeneration	0			(263)	67	348	591	316	8	18	(12)
13	Combined Cycle CT	0			(11)	60	50	(183)	34	(95)	(90)	54
14	Coal	0			0	0	0	0	0	0	0	0
15	Transmission	0			0	0	0	0	0	0	0	0
16	Peaking Resources	0			0	0	0	0	0	0	0	0
17	**Total Resources**	0			(186)	30	(14)	(25)	343	(92)	(79)	65
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO_2	0			388	-758	-85	224	#N/A	-94	-71	127
19	NOx	0			0	-2	0	1	#N/A	0	0	0
	Financial Results with End Effects to 2045											
20	50-year Utility Cost											
21	NPV at 8.6% (million $)	0			-276	50	712	1,060	910	4	11	18
22	Real Levelized (mills/kWh)	0.00			-0.57	0.09	0.76	1.31	-1.03	0.45	0.41	-0.38
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	0			-381	62	726	1,168	481	269	235	-85
25	Real Levelized (mills/kWh)	0.00			-0.37	0.05	0.69	1.11	0.45	0.25	0.22	-0.09
25	**IPM Obj Function (millions $)**	0			-234	226	322	415	456	-240	-166	143

(A) Case 2 and 3 are RAMPP-3 models. Since these models did not have a 2005 run year, 2003 is presented. Therefore these two cases should only be compared against each other.

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)
Resource Selections by 10th year, Emissions and Financial Results

	Case Name	Base Case Study	Load Growth Rate Medium Low	Load Growth Rate Medium High	Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices High	High Gas Price Non-firm Prices Med	Lumped Resource Additions	Non-Firm Prices Lower by 25%	Non-Firm Prices Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Summer Peak Capacity in Year 2005 (MW)										
1	Native Load	0	(1,210)	1,310	0	0	0	0	0	0	0
2	Firm Sales	0	0	0	0	0	0	0	0	0	0
3	less DSM	0	241	(153)	50	(40)	(48)	(83)	(14)	5	(2)
4	**Total Requirements**	0	(969)	1,157	50	(40)	(48)	(83)	(14)	5	(2)
5	Existing Generation	0	1	1	1	1	1	1	1	1	0
6	Firm Purchases	0	0	0	0	0	0	0	0	0	0
7	New Resources										
8	Renewable	0	0	0	0	0	0	0	0	0	0
9	Cogeneration	0	(363)	1,221	(20)	178	169	129	(63)	(69)	(23)
10	Combined Cycle CT	0	(222)	75	75	(222)	(222)	(222)	75	75	21
11	Coal	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	0	0	0	0	0	0
14	**Total Resources**	0	(585)	1,297	56	(44)	(53)	(92)	13	6	(2)
15	Reserves	0	384	139	6	(4)	(5)	(10)	28	1	0
16	Reserve Margin (RM) (%)	0.0	5.6	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0
	Winter Peak Capacity in Year 2005 (MW)										
17	Native Load	0	(1,209)	1,369	0	0	0	0	0	0	0
18	Firm Sales	0	0	0	0	0	0	0	0	0	0
19	less DSM	0	315	(173)	52	(36)	(41)	(68)	(14)	8	(4)
20	**Total Requirements**	0	(894)	1,196	52	(36)	(41)	(68)	(14)	8	(4)
21	Existing Generation	0	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
22	Firm Purchases	0	0	0	0	0	0	0	0	0	0
23	New Resources										
24	Renewable	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	0	(387)	1,299	(21)	189	180	137	(67)	(74)	(25)
26	Combined Cycle CT	0	(248)	84	84	(248)	(248)	(248)	84	84	23
27	Coal	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	0	0	0	0	0	0
30	**Total Resources**	0	(635)	1,382	62	(59)	(68)	(111)	17	9	(2)
31	Reserves	0	260	186	10	(23)	(28)	(43)	30	1	2
32	Reserve Margin (RM) (%)	0.0	4.5	0.0	0.0	(0.2)	(0.2)	(0.3)	0.3	(0.0)	0.0

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)
Resource Selections by 10th year, Emissions and Financial Results

		Base Case Study	Load Growth Rate		Low Gas Prices	Limited Medium $ Gas	High Gas Price Non-firm Prices		Lumped Resource Additions	Non-Firm Prices	
	Case Name		Medium Low	Medium High			High	Med		Lower by 25%	Higher by 25%
	Case #	1	21	22	31	32	33	34	41	42	43
	Annual Energy in Year 2005 (MWa)										
1	Native Load	0	(867)	976	0	0	0	0	0	0	0
2	Pump Storage/Peak Return	0	0	0	0	0	0	0	0	0	0
3	Firm Sales	0	0	0	0	0	0	0	0	0	0
4	Non-Firm Sales	0	57	171	(61)	4	6	(35)	18	(276)	69
5	less DSM	0	159	(102)	49	(24)	(28)	(46)	(12)	6	(3)
6	**Total Requirements**	0	(651)	1,045	(12)	(20)	(22)	(81)	6	(270)	66
7	Existing Generation	0	(116)	(88)	(96)	(20)	(17)	(53)	15	(254)	62
8	Firm Purchases	0	0	0	0	0	0	0	0	0	0
9	Non-Firm Purchases	0	8	0	20	10	12	27	5	125	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	0	(360)	1,153	(20)	173	165	128	(62)	(71)	(23)
13	Combined Cycle CT	0	(183)	(20)	84	(183)	(183)	(183)	49	(69)	27
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	0	0	0
17	**Total Resources**	0	(651)	1,045	(12)	(20)	(22)	(81)	6	(270)	66
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	0	-2,250	2,794	-460	219	308	320	-79	-1,004	16
19	NOx	0	-1	0	-2	1	1	1	0	-4	0
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	0	-3,639	4,574	88	-637	-103	491	-249	898	-996
22	Real Levelized (mills/kWh)	0.00	1.37	-1.24	-0.34	-0.44	0.14	0.89	-0.17	0.84	-0.98
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	0	-3,928	4,858	-17	-545	5	715	-217	895	-993
25	Real Levelized (mills/kWh)	0.00	1.96	-1.43	-0.02	-0.53	0.00	0.68	-0.21	0.85	-0.95
25	**IPM Obj Function (millions $)**	0	-4,269	5,320	-51	-303	-66	628	11	827	-826

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)
Resource Selections by 10th year, Emissions and Financial Results

		Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
	Case Name		25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	CCCT+2 25% Lower	CCCT+6 Medium	CCCT+10 25% Higher
	Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Summer Peak Capacity in Year 2005 (MW)										
1	Native Load	0	0	0	0	0	0	0	0	0	0
2	Firm Sales	0	0	0	0	0	0	0	0	0	0
3	less DSM	0	8	1	1	13	5	5	(1)	(10)	(10)
4	**Total Requirements**	0	8	1	1	13	5	5	(1)	(10)	(10)
5	Existing Generation	0	1	0	(0)	0	(0)	(0)	0	0	0
6	Firm Purchases	0	0	0	0	0	0	0	0	0	0
7	New Resources										
8	Renewable	0	0	0	0	0	0	0	0	0	0
9	Cogeneration	0	(67)	0	8	107	107	107	(278)	(213)	(19)
10	Combined Cycle CT	0	75	1	3	(92)	(102)	(53)	(54)	(120)	(54)
11	Coal	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	0	0	0	331	321	321
14	**Total Resources**	0	9	2	11	14	5	53	(1)	(11)	248
15	Reserves	0	1	0	10	2	0	48	0	(1)	258
16	Reserve Margin (RM) (%)	0.0	0.0	0.0	0.1	0.0	0.0	0.5	0.0	0.0	2.6
	Winter Peak Capacity in Year 2005 (MW)										
17	Native Load	0	0	0	0	0	0	0	0	0	0
18	Firm Sales	0	0	0	0	0	0	0	0	0	0
19	less DSM	0	11	2	(1)	17	5	4	2	(12)	(13)
20	**Total Requirements**	0	11	2	(1)	17	5	4	2	(12)	(14)
21	Existing Generation	0	(1)	0	(0)	0	(0)	(0)	(1)	(1)	(1)
22	Firm Purchases	0	0	0	0	0	0	0	0	0	0
23	New Resources										
24	Renewable	0	0	0	0	0	0	0	0	0	0
25	Cogeneration	0	(71)	0	8	113	113	113	(295)	(227)	(21)
26	Combined Cycle CT	0	84	1	4	(103)	(113)	(59)	(60)	(134)	(60)
27	Coal	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	0	0	0	352	342	342
30	**Total Resources**	0	12	2	12	10	0	54	(5)	(19)	260
31	Reserves	0	1	(0)	13	(6)	(5)	50	(6)	(7)	274
32	Reserve Margin (RM) (%)	0.0	(0.0)	(0.0)	0.1	(0.1)	(0.1)	0.5	(0.1)	(0.1)	2.9

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)
Resource Selections by 10th year, Emissions and Financial Results

		Base Case Study	Overbuild by 250 MW in 1999 with Non-Firm Prices that are			Overbuild by 500 MW in 1999 with Non-Firm Prices that are			Underbuilding until 2005		
									CCCT+2	CCCT+6	CCCT+10
	Case Name		25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher	25% Lower	Medium	25% Higher
	Case #	1	44	45	46	47	48	49	50 (A)	51 (A)	52 (A)
	Annual Energy in Year 2005 (MWa)										
1	Native Load	0	0	0	0	0	0	0	0	0	0
2	Pump Storage/Peak Return	0	0	0	0	0	0	0	0	0	0
3	Firm Sales	0	0	0	0	0	0	0	0	0	0
4	Non-Firm Sales	0	(283)	2	73	(248)	(3)	90	(420)	(226)	87
5	less DSM	0	8	1	0	13	4	4	0	(11)	(11)
6	Total Requirements	0	(275)	3	73	(235)	2	94	(419)	(237)	76
7	Existing Generation	0	(254)	0	54	(249)	(26)	23	(248)	10	54
8	Firm Purchases	0	0	0	0	0	0	0	0	0	0
9	Non-Firm Purchases	0	148	2	0	107	6	0	204	49	0
10	New Resources										
11	Renewable	0	0	0	0	0	0	0	0	0	0
12	Cogeneration	0	(99)	0	8	40	105	105	(275)	(211)	(19)
13	Combined Cycle CT	0	(69)	1	12	(133)	(83)	(34)	(115)	(97)	(33)
14	Coal	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	0	0	0	13	13	75
17	Total Resources	0	(275)	3	73	(235)	2	94	(420)	(237)	76
	Average Annual Emission in 1996-2045 (1000 tons)										
18	CO_2	0	-1,036	-3	37	-1,099	-54	-31	-845	145	122
19	NOx	0	-4	0	0	-4	0	0	-3	0	0
	Financial Results with End Effects to 2045										
20	50-year Utility Cost										
21	NPV at 8.6% (million $)	0	952	38	-885	1,081	207	-781	1,147	405	-841
22	Real Levelized (mills/kWh)	0.00	0.88	0.03	-0.91	0.98	0.18	-0.81	1.13	0.48	-0.76
23	50-year Total Resources Cost										
24	NPV at 8.6% (million $)	0	942	35	-892	1,061	197	-794	1,156	425	-823
25	Real Levelized (mills/kWh)	0.00	0.90	0.03	-0.86	1.01	0.18	-0.76	1.10	0.40	-0.79
25	IPM Obj Function (millions $)	0	879	26	-819	944	63	-796	863	157	-621

Note: (A) An additional 2, 6, or 10 mill/kWh was added to the CCCT cost to represent an additonal profit margin for an energy producer selling power in a sellers market.

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)
Resource Selections by 10th year, Emissions and Financial Results

		Base Case Study	Added Transm			Cheaper Renew-ables	Extend Inputs to 2045			Environmental Adders with CO2 Costs at		
	Case Name		Test Transm Conversion	Bridger to OWC	Utah to OWC		Firm Contracts	Loads and DSM	All Inputs	$10/ton	$25/ton	$40/ton
	Case #	1	57	58	59	61	65	66	67	71	72	73
	Summer Peak Capacity in Year 2005 (MW)											
1	Native Load	0	0	0	0	0	0	0	0	0	0	0
2	Firm Sales	0	0	0	0	0	645	0	645	0	0	0
3	less DSM	0	(49)	(0)	0	4	(17)	21	(20)	(10)	(73)	(107)
4	**Total Requirements**	0	(49)	(0)	0	4	628	21	625	(10)	(73)	(107)
5	Existing Generation	0	0	(0)	0	0	1	0	1	1	1	1
6	Firm Purchases	0	0	0	0	0	268	0	268	0	0	0
7	New Resources											0
8	Renewable	0	0	0	0	54	0	0	0	0	592	876
9	Cogeneration	0	(131)	0	0	(147)	360	(9)	356	622	1,610	1,297
10	Combined Cycle CT	0	75	(0)	0	(102)	75	32	75	75	1,667	2,310
11	Coal	0	0	0	0	0	0	0	0	0	0	0
12	Transmission	0	0	0	0	0	0	0	0	0	0	0
13	Peaking Resources	0	0	0	0	200	0	0	0	0	0	0
14	**Total Resources**	0	(55)	(0)	0	5	703	23	700	697	3,870	4,484
15	Reserves	0	(6)	(0)	0	(35)	76	3	75	707	3,548	4,007
16	Reserve Margin (RM) (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.1	40.0	46.8
	Winter Peak Capacity in Year 2005 (MW)											
17	Native Load	0	0	0	0	0	0	0	0	0	0	0
18	Firm Sales	0	0	0	0	0	468	0	468	0	0	0
19	less DSM	0	(41)	1	0	7	(13)	19	(16)	(16)	(63)	(91)
20	**Total Requirements**	0	(41)	1	0	7	455	19	452	(16)	(63)	(91)
21	Existing Generation	0	(1)	(0)	0	0	(1)	0	(1)	(1)	(1)	(1)
22	Firm Purchases	0	0	0	0	0	635	0	635	0	0	0
23	New Resources											
24	Renewable	0	0	0	0	54	0	0	0	0	712	1,166
25	Cogeneration	0	(139)	0	0	(156)	383	(9)	379	661	1,712	1,380
26	Combined Cycle CT	0	84	(0)	0	(114)	84	35	84	84	1,777	2,461
27	Coal	0	0	0	0	0	0	0	0	0	0	0
28	Transmission	0	0	0	0	0	0	0	0	0	0	0
29	Peaking Resources	0	0	0	0	200	0	0	0	0	0	0
30	**Total Resources**	0	(56)	(0)	0	(17)	1,101	26	1,097	744	4,201	5,006
31	Reserves	0	(15)	(1)	0	(24)	646	7	645	760	4,264	5,097
32	Reserve Margin (RM) (%)	0.0	(0.1)	(0.0)	0.0	(0.3)	5.7	0.0	5.7	7.9	44.6	53.4

Comparative Results of RAMPP-4 Runs (Case Results less Case 1)
Resource Selections by 10th year, Emissions and Financial Results

		Base Case Study	Added Transm			Cheaper Renew-ables	Extend Inputs to 2045			Environmental Adders with CO2 Costs at		
			Test Transm Conversion	Bridger to OWC	Utah to OWC		Firm Contracts	Loads and DSM	All Inputs	$10/ton	$25/ton	$40/ton
	Case #	1	57	58	59	61	65	66	67	71	72	73
	Annual Energy in Year 2005 (MWa)											
1	Native Load	0	0	0	0	0	0	0	0	0	0	0
2	Pump Storage/Peak Return	0	0	0	0	0	0	0	0	0	(5)	0
3	Firm Sales	0	0	0	0	0	417	0	417	0	0	0
4	Non-Firm Sales	0	(32)	33	4	(9)	50	9	49	(682)	(741)	(638)
5	less DSM	0	(28)	(0)	0	5	(12)	17	(11)	(12)	(43)	(59)
6	Total Requirements	0	(60)	33	4	(5)	455	26	455	(693)	(789)	(697)
7	Existing Generation	0	17	19	0	(29)	(44)	8	(42)	(1,876)	(5,315)	(5,770)
8	Firm Purchases	0	0	0	0	0	124	0	124	0	3	3
9	Non-Firm Purchases	0	3	0	4	5	0	4	0	449	627	498
10	New Resources											
11	Renewable	0	0	0	0	51	0	0	0	0	608	956
12	Cogeneration	0	(129)	0	0	(145)	356	(9)	353	615	1,593	1,284
13	Combined Cycle CT	0	50	13	0	(84)	19	22	21	119	1,695	2,331
14	Coal	0	0	0	0	0	0	0	0	0	0	0
15	Transmission	0	0	0	0	0	0	0	0	0	0	0
16	Peaking Resources	0	0	0	0	198	0	0	0	0	0	0
17	Total Resources	0	(60)	33	4	(5)	455	26	456	(693)	(789)	(698)
	Average Annual Emission in 1996-2045 (1000 tons)											
18	CO_2	0	-29	132	23	-972	-337	32	-351	-10,277	-30,233	-34,550
19	NO_x	0	0	0	0	0	0	0	0	-34	-93	-103
	Financial Results with End Effects to 2045											
20	50-year Utility Cost											
21	NPV at 8.6% (million $)	0	-683	478	500	-283	-288	2,465	2,581	1,105	9,827	12,991
22	Real Levelized (mills/kWh)	0.00	-0.43	0.48	0.50	-0.36	-0.20	-1.26	-1.02	1.19	10.29	13.61
23	50-year Total Resources Cost											
24	NPV at 8.6% (million $)	0	-564	479	500	-293	-246	2,483	2,666	1,120	10,037	13,286
25	Real Levelized (mills/kWh)	0.00	-0.54	0.45	0.47	-0.28	-0.24	-1.10	-0.94	1.06	9.58	12.69
25	IPM Obj Function (millions $)	0	377	-9	-1	-506	2,957	3,416	7,183	15,573	27,649	37,322

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Med Load - Med Gas

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.1	15.4	16.1	16.4	16.8	17.1	16.9	17.1	33.4	49.6	46.1	56.5	315.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2									62.6	276.3	517.7	384.2	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	14.1	15.4	16.1	16.4	16.8	17.1	16.9	167.5	246.4	325.9	563.8	440.7	1857.1
	DSM Programs	11.4	12.5	14.3	14.4	14.5	14.5	14.3	14.4	28.4	43.0	40.8	51.0	273.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											219.5	175.3	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							13.4	168.0	40.7				222.1
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	11.4	12.5	14.3	14.4	14.5	14.5	27.7	182.4	69.1	43.0	260.3	226.3	890.4
	DSM Programs	4.5	4.5	4.6	5.2	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.7	100.0
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.5	4.5	4.6	5.2	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.7	100.0
	DSM Programs	30.0	32.4	35.0	36.0	36.6	36.9	36.5	36.8	72.2	108.5	101.9	126.2	689.0
T	Renewable													0.0
O	Cogeneration								150.4	213.0	276.3	737.2	559.5	1936.4
T	Combined Cycle CT							13.4	168.0	40.7				222.1
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	30.0	32.4	35.0	36.0	36.6	36.9	49.9	355.2	325.9	384.8	839.1	685.7	2847.5

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(30)	(62)	(97)	(133)	(170)	(207)	(243)	(280)	(352)	(461)	(563)	(689)
T	**Total Requirements**	9,024	9,154	9,260	9,365	9,580	9,583	9,759	9,928	9,940	10,089	10,573	11,020
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,207	10,123	10,014	9,869	9,844
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							13	332	586	862	1,599	2,159
&	Summer Purch $6/Year							109					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,930	11,118	11,132	11,299	11,842	12,343
	Reserves	1,226	1,587	1,544	1,443	1,237	1,225	1,171	1,190	1,192	1,210	1,268	1,323
	Reserve Margin (RM) (%)	13.6	17.3	16.7	15.4	12.9	12.8	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.0	21.3	22.6	23.3	24.2	24.4	24.5	24.9	48.6	71.8	65.5	79.2	448.3
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2									66.6	293.9	550.7	408.8	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.0**	**21.3**	**22.6**	**23.3**	**24.2**	**24.4**	**24.5**	**184.9**	**275.2**	**365.7**	**616.2**	**488.0**	**2088.3**
	DSM Programs	13.8	15.3	17.4	17.5	17.7	17.5	17.3	17.3	34.1	51.3	47.7	59.1	326.0
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											233.6	186.4	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							15.0	187.2	45.3				247.5
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**15.3**	**17.4**	**17.5**	**17.7**	**17.5**	**32.3**	**204.5**	**79.4**	**51.3**	**281.3**	**245.5**	**993.5**
	DSM Programs	4.0	4.1	4.1	4.8	4.9	4.9	4.9	4.9	9.7	14.6	13.7	16.9	91.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.0**	**4.1**	**4.1**	**4.8**	**4.9**	**4.9**	**4.9**	**4.9**	**9.7**	**14.6**	**13.7**	**16.9**	**91.5**
	DSM Programs	35.8	40.7	44.1	45.6	46.8	46.8	46.7	47.1	92.4	137.7	126.9	155.2	865.8
T	Renewable													0.0
O	Cogeneration								160.0	226.6	293.9	784.3	595.2	2060.0
T	Combined Cycle CT							15.0	187.2	45.3				247.5
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**35.8**	**40.7**	**44.1**	**45.6**	**46.8**	**46.8**	**61.7**	**394.3**	**364.3**	**431.6**	**911.2**	**750.4**	**3173.3**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(36)	(77)	(121)	(166)	(213)	(260)	(307)	(354)	(446)	(584)	(711)	(866)
T	**Total Requirements**	**8,996**	**9,018**	**9,078**	**9,091**	**9,185**	**9,332**	**9,485**	**9,653**	**9,653**	**9,885**	**10,245**	**10,656**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,254	10,162	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							15	362	634	928	1,712	2,308
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,035**	**11,378**	**11,115**	**11,244**	**11,874**	**12,445**
	Reserves	1,352	1,833	1,942	1,950	1,841	1,686	1,550	1,724	1,462	1,358	1,628	1,789
	Reserve Margin (RM) (%)	15.0	20.3	21.4	21.5	20.0	18.1	16.3	17.9	15.1	13.7	15.9	16.8

Case # 1

Med Load - Med Gas

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.0	18.8	29.1	39.6	50.4	61.4	72.4	83.5	105.2	137.6	167.7	204.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal								148.9	297.9	297.9	297.9	297.9
W	OWC Cogen 1									62.0	335.4	818.3	1,100.7
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	9.0	18.8	29.1	39.6	50.4	61.4	72.4	232.4	465.1	770.8	1,284.0	1,603.4
	DSM Programs	8.1	16.9	27.3	37.7	48.3	58.8	69.2	79.7	100.3	131.7	161.5	199.0
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1											212.3	367.2
U	Utah Cogen 2												
T	Utah Combined Cycle							11.2	141.9	182.8	188.8	155.9	114.3
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	8.1	16.9	27.3	37.7	48.3	58.8	80.4	221.5	283.1	320.4	529.8	680.5
	DSM Programs	3.3	6.7	10.1	14.2	18.3	22.4	26.5	30.6	38.7	51.0	62.7	77.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	3.3	6.7	10.1	14.2	18.3	22.4	26.5	30.6	38.7	51.0	62.7	77.4
	DSM Programs	20.5	42.4	66.5	91.5	117.0	142.5	168.1	193.7	244.2	320.2	392.0	481.1
T	Renewable								148.9	359.9	633.3	1,328.6	1,765.8
O	Cogeneration							11.2	141.9	182.8	188.8	155.9	114.3
T	Combined Cycle CT												
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	20.5	42.4	66.5	91.5	117.0	142.5	179.3	484.5	786.8	1,142.2	1,876.5	2,361.2
S	Native Load 69%	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	Pump Storage/Peak Return	310.6	310.1	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	Firm Sales	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	Non-Firm Sales	502.4	756.9	791.2	762.1	709.0	680.3	601.7	767.9	921.2	946.1	1,145.4	1,244.1
E	DSM Programs	(20.5)	(42.4)	(66.5)	(91.5)	(117.0)	(142.5)	(168.1)	(193.7)	(244.2)	(320.2)	(392.0)	(481.1)
M	Total Requirements	7,812.6	8,064.2	8,090.9	8,106.5	8,161.5	8,204.6	8,243.2	8,504.3	8,710.2	8,955.8	9,446.1	9,728.6
	Existing Generation	7,161.2	7,516.3	7,578.5	7,603.8	7,658.1	7,695.8	7,720.3	7,747.9	7,768.0	7,739.6	7,583.0	7,489.9
L	Firm Purchases	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	Non-Firm Purchases 1%	94.4	44.2	39.5	38.1	49.3	63.4	69.5	26.4		12.4		
R	New Resources							11.2	290.8	542.6	822.0	1,484.4	1,880.1
	Total Resources	7,812.6	8,064.2	8,090.9	8,106.6	8,161.5	8,204.6	8,243.2	8,504.3	8,710.2	8,955.8	9,446.1	9,728.5

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Case # 1

Med Load - Med Gas

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	20	42	66	91	116	142	168	193	245	322	393	487
			After Conservation												
			System Load (MWa)	5,704	5,685	5,728	5,814	5,942	6,038	6,155	6,285	6,528	6,920	7,268	7,655
	0.52		Energy Sales (MWa)	5,155	5,164	5,225	5,315	5,417	5,523	5,631	5,740	5,909	6,151	6,476	6,629
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,078	8,274	8,459	8,662	8,855	9,246	9,710	10,057	10,661	11,630	13,290	15,178
			Net Conservation Assets ($M)	46	93	144	180	213	246	276	305	356	412	440	485
			Utility Cost												
42,560	3.28	Nominal	**Operating Revenues ($M)**	2,212	2,198	2,236	2,327	2,424	2,547	2,638	2,670	2,943	3,376	3,888	4,531
	-0.02	Real		2,212	2,127	2,096	2,111	2,129	2,166	2,171	2,127	2,197	2,287	2,389	2,445
	2.74	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.0	51.1	52.7	53.5	53.1	56.9	62.7	68.5	78.0
	-0.54	Real		49.0	47.0	45.8	45.3	44.9	44.8	44.0	42.3	42.5	42.4	42.1	42.1
		Nominal	Average Customer Bill ($)	1,668	1,641	1,648	1,687	1,725	1,784	1,817	1,808	1,931	2,111	2,332	2,647
		Real		1,668	1,588	1,544	1,530	1,515	1,516	1,496	1,441	1,441	1,430	1,433	1,428
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.6	5.0	7.2	9.0	10.7	11.9	12.2	7.1	-3.3	-28.3
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.1	1.9	2.8	3.9	5.2	7.8	10.8	11.4	11.4
			Energy Svc Charge ($M)	3.9	8.2	13.0	16.1	19.4	22.7	26.1	29.7	37.1	48.9	57.5	60.6
42,990	3.28	Nominal	**Total Resource Cost ($M)**	2,216	2,206	2,250	2,344	2,446	2,573	2,668	2,704	2,988	3,436	3,957	4,603
	-0.02	Real		2,216	2,136	2,109	2,127	2,148	2,187	2,196	2,155	2,231	2,327	2,431	2,484
	2.60	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.6	50.5	52.0	52.7	52.2	55.6	60.9	66.1	74.3
	-0.67	Real		48.9	46.9	45.5	45.0	44.4	44.2	43.3	41.6	41.5	41.2	40.6	40.1

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.55

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.07

Med Load - Med Gas

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,971	49,798	50,173	50,903	52,016	52,862	53,888	55,027	57,146	60,591	67,067	66,753
	MWa	5,704	5,685	5,728	5,811	5,938	6,034	6,152	6,282	6,523	6,917	7,656	7,620
	Total Annual Emissions (1000 Tons)												
0.14%	CO2	51,948	51,960	52,126	52,588	53,318	53,764	54,255	54,617	55,617	57,470	59,181	53,321
0.21%	NOx	121.1	121.5	121.9	122.4	123.2	123.6	126.6	126.0	126.2	126.6	126.8	126.1
0.25%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.1	11.1	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.38%	CO2	2,079	2,087	2,078	2,066	2,050	2,034	2,014	1,985	1,946	1,897	1,765	1,598
-1.31%	NOx	4.85	4.88	4.86	4.81	4.74	4.67	4.70	4.58	4.42	4.18	3.78	3.78
-1.27%	TSP	0.43	0.44	0.44	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.37	99.94	99.38	98.60	97.84	96.85	95.48	93.62	91.24	84.88	76.84
	NOx	100	100.68	100.25	99.19	97.74	96.42	96.89	94.48	91.12	86.20	77.98	77.91
	TSP	100	100.51	100.15	99.20	97.74	96.58	95.06	93.18	90.14	85.63	77.67	78.44

20 Year Emissions (1000 Tons)

	Average	Total
CO2	55,189	1,103,773
NOx	125.2	2,504
TSP	11.2	224

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No Summer Results for Case #4

Case # 4

Med Load - Med Gas
with No Summer Season

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.5	20.6	23.7	25.2	27.0	28.4	30.1	31.6	65.9	107.0	112.9	158.1	647.0
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1													0.0
C	OWC Cogen 2									104.4	215.6			320.0
	OWC Combined Cycle										168.6	503.3	228.3	900.2
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	16.5	20.6	23.7	25.2	27.0	28.4	30.1	31.6	170.3	491.2	616.2	386.4	1867.2
	DSM Programs	9.3	10.2	13.3	13.4	15.2	15.0	14.8	15.6	33.1	50.1	46.5	58.3	294.8
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2													0.0
T	Utah Combined Cycle												164.0	164.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4								162.2	66.4				228.6
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	9.3	10.2	13.3	13.4	15.2	15.0	14.8	177.8	99.5	50.1	46.5	222.3	687.4
	DSM Programs	1.8	1.9	1.9	2.4	3.7	3.9	4.7	4.7	10.7	16.6	16.0	20.4	88.7
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	1.8	1.9	1.9	2.4	3.7	3.9	4.7	4.7	10.7	16.6	16.0	20.4	88.7
	DSM Programs	27.6	32.7	38.9	41.0	45.9	47.3	49.6	51.9	109.7	173.7	175.4	236.8	1030.5
T	Renewable													0.0
O	Cogeneration													0.0
T	Combined Cycle CT									104.4	384.2	503.3	392.3	1384.2
A	Coal & IGCC								162.2	66.4				228.6
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	27.6	32.7	38.9	41.0	45.9	47.3	49.6	214.1	280.5	557.9	678.7	629.1	2643.3

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(28)	(60)	(99)	(140)	(186)	(233)	(283)	(335)	(445)	(618)	(794)	(1,031)
T	**Total Requirements**	**9,004**	**9,034**	**9,100**	**9,117**	**9,212**	**9,359**	**9,508**	**9,672**	**9,654**	**9,851**	**10,162**	**10,492**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,892	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								162	333	717	1,221	1,613
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,850	11,020	11,041	11,026	11,018	11,020	11,178	10,813	11,033	11,382	11,751
	Reserves	1,344	1,816	1,920	1,924	1,814	1,659	1,512	1,506	1,159	1,183	1,219	1,259
	Reserve Margin (RM) (%)	14.9	20.1	21.1	21.1	19.7	17.7	15.9	15.6	12.0	12.0	12.0	12.0

Case # 4

Med Load - Med Gas
with No Summer Season

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	6.6	14.0	22.8	31.9	41.3	50.9	61.4	72.1	93.5	125.9	156.9	196.5
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal									97.2	297.9	297.9	297.9
W	OWC Cogen 1										156.9	625.2	829.2
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**6.6**	**14.0**	**22.8**	**31.9**	**41.3**	**50.9**	**61.4**	**72.1**	**190.6**	**580.6**	**1,079.9**	**1,323.6**
	DSM Programs	4.8	9.8	16.6	23.4	31.9	40.3	48.7	57.5	77.5	107.9	136.9	173.7
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												152.6
U	Utah Cogen 2												
T	Utah Combined Cycle								121.7	171.9	177.8	180.2	185.3
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**4.8**	**9.8**	**16.6**	**23.4**	**31.9**	**40.3**	**48.7**	**179.3**	**249.4**	**285.7**	**317.0**	**511.6**
	DSM Programs	1.6	3.3	4.9	6.9	10.0	13.2	16.8	20.4	28.8	41.7	54.2	70.1
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**1.6**	**3.3**	**4.9**	**6.9**	**10.0**	**13.2**	**16.8**	**20.4**	**28.8**	**41.7**	**54.2**	**70.1**
	DSM Programs	13.0	27.1	44.3	62.1	83.2	104.5	126.9	150.0	199.8	275.5	347.9	440.3
T	Renewable									97.2	454.7	923.0	1,279.7
O	Cogeneration								121.7	171.9	177.8	180.2	185.3
T	Combined Cycle CT												
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**13.0**	**27.1**	**44.3**	**62.1**	**83.2**	**104.5**	**126.9**	**271.7**	**468.9**	**908.0**	**1,451.1**	**1,905.3**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	517.2	753.1	786.1	754.3	677.8	654.0	573.3	614.6	690.8	763.8	825.5	966.8
E	**DSM Programs**	(12.9)	(27.1)	(44.3)	(62.1)	(83.2)	(104.5)	(126.9)	(150.0)	(199.8)	(275.5)	(347.9)	(440.3)
M	**Total Requirements**	7,834.9	8,075.8	8,108.1	8,128.1	8,164.1	8,216.5	8,256.0	8,394.7	8,524.1	8,818.2	9,170.3	9,492.1
	Existing Generation	7,161.6	7,518.0	7,587.5	7,612.1	7,667.0	7,702.9	7,716.7	7,771.2	7,809.1	7,764.4	7,663.9	7,637.4
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	116.3	54.0	47.7	51.4	43.0	68.0	97.1	62.6	46.4	39.5	24.7	31.2
R	**New Resources**								121.7	269.1	632.5	1,103.2	1,465.0
	Total Resources	7,834.9	8,075.8	8,108.1	8,128.2	8,164.1	8,216.5	8,256.0	8,394.6	8,524.1	8,818.2	9,170.3	9,492.1

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Case # 4

Med Load - Med Gas
with No Summer Season

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	13	27	44	62	83	104	126	149	196	269	337	428
			After Conservation												
			System Load (MWa)	5,711	5,700	5,750	5,843	5,975	6,076	6,197	6,330	6,577	6,973	7,323	7,715
	0.54		Energy Sales (MWa)	5,161	5,178	5,245	5,342	5,448	5,558	5,669	5,782	5,954	6,199	6,527	6,684
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,062	8,240	8,412	8,607	8,777	9,038	9,336	9,634	10,199	11,441	12,737	14,398
			Net Conservation Assets ($M)	29	59	97	126	157	188	217	246	302	374	421	478
			Utility Cost												
42,284	3.28	Nominal	**Operating Revenues ($M)**	2,213	2,199	2,238	2,329	2,427	2,551	2,636	2,685	2,919	3,339	3,890	4,470
	-0.02	Real		2,213	2,129	2,098	2,113	2,131	2,169	2,169	2,139	2,179	2,262	2,390	2,412
	2.72	Nominal	Cost in mills/kWh	49.0	48.5	48.7	49.8	50.9	52.4	53.1	53.0	56.0	61.5	68.0	76.3
	-0.56	Real		49.0	46.9	45.7	45.2	44.7	44.5	43.7	42.2	41.8	41.7	41.8	41.2
		Nominal	Average Customer Bill ($)	1,669	1,642	1,649	1,688	1,727	1,786	1,816	1,819	1,914	2,089	2,333	2,611
		Real		1,669	1,590	1,546	1,531	1,517	1,518	1,494	1,449	1,429	1,415	1,434	1,409
			Total Resource Cost												
			DSR Customer Cost ($M)	0.0	0.2	0.6	1.8	3.3	4.3	5.3	5.7	4.7	-2.0	-14.8	-42.7
			Levelized (20-year at 8.6%)	0.0	0.0	0.1	0.3	0.6	1.1	1.7	2.3	3.3	3.8	3.8	3.8
			Energy Svc Charge ($M)	2.3	4.8	8.2	10.5	13.3	16.1	19.1	22.2	29.0	40.4	50.2	57.1
42,610	3.27	Nominal	**Total Resource Cost ($M)**	2,216	2,204	2,247	2,340	2,441	2,568	2,657	2,709	2,951	3,384	3,944	4,531
	-0.03	Real		2,216	2,134	2,105	2,123	2,143	2,183	2,187	2,159	2,203	2,292	2,424	2,445
	2.60	Nominal	Cost in mills/kWh	48.9	48.4	48.5	49.5	50.4	51.9	52.4	52.3	54.9	59.9	65.9	73.1
	-0.68	Real		48.9	46.8	45.5	44.9	44.3	44.1	43.2	41.6	41.0	40.6	40.5	39.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.98**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.70**

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Med Load - Med Gas
with No Summer Season

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	50,036	49,932	50,368	51,161	52,312	53,196	54,249	55,410	57,534	60,983	67,425	66,849
	MWa	5,712	5,700	5,750	5,840	5,972	6,073	6,193	6,325	6,568	6,962	7,697	7,631
	Total Annual Emissions (1000 Tons)												
0.30%	CO2	51,979	52,029	52,231	52,726	53,488	53,944	54,426	54,857	55,858	57,726	59,468	54,986
0.24%	NOx	121.2	121.6	122.0	122.5	123.4	123.7	126.6	126.3	126.5	126.9	127.3	126.7
0.26%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.1	11.2	11.2	11.3	11.4	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.22%	CO2	2,078	2,084	2,074	2,061	2,045	2,028	2,007	1,980	1,942	1,893	1,764	1,645
-1.28%	NOx	4.84	4.87	4.84	4.79	4.72	4.65	4.67	4.56	4.40	4.16	3.77	3.79
-1.26%	TSP	0.43	0.44	0.43	0.43	0.42	0.42	0.41	0.40	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.30	99.82	99.21	98.42	97.62	96.58	95.30	93.46	91.12	84.90	79.18
	NOx	100	100.56	100.03	98.88	97.42	96.03	96.41	94.17	90.84	85.97	77.95	78.29
	TSP	100	100.41	99.96	98.91	97.45	96.21	94.58	92.80	89.81	85.41	77.60	78.58

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,577	1,111,536
NOx	125.5	2,510
TSP	11.2	224

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Med Load - Med Gas
with No Turbine Upgrades

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.1	15.6	16.1	16.5	16.8	17.1	17.0	17.1	33.4	49.7	46.0	56.5	315.9
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2								56.9	72.9	275.2	478.8	357.0	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.1**	**15.6**	**16.1**	**16.5**	**16.8**	**17.1**	**17.0**	**224.4**	**256.7**	**324.9**	**524.8**	**413.5**	**1857.5**
	DSM Programs	12.1	13.9	14.3	14.7	14.8	14.8	14.6	14.8	28.9	44.0	41.8	52.0	280.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1												36.7	36.7
U	Utah Cogen 2											257.4	137.4	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							99.7	168.0	29.6	(0.0)	(0.0)	(0.0)	297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												27.2	27.2
	Total	12.1	13.9	14.3	14.7	14.8	14.8	114.3	182.8	58.5	44.0	299.2	253.3	1036.7
	DSM Programs	4.5	5.1	5.2	5.2	5.3	5.3	5.3	5.3	10.5	15.8	15.0	18.7	101.2
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.5	5.1	5.2	5.2	5.3	5.3	5.3	5.3	10.5	15.8	15.0	18.7	101.2
	DSM Programs	30.7	34.6	35.6	36.4	36.9	37.2	36.9	37.2	72.8	109.5	102.8	127.2	697.8
T	Renewable													0.0
O	Cogeneration								207.3	223.3	275.2	736.2	531.1	1973.1
T	Combined Cycle CT							99.7	168.0	29.6	(0.0)	(0.0)	(0.0)	297.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												27.2	27.2
	Total	30.7	34.6	35.6	36.4	36.9	37.2	136.6	412.5	325.7	384.7	839.0	685.5	2995.4

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(31)	(65)	(101)	(137)	(174)	(211)	(248)	(286)	(358)	(468)	(571)	(698)
T	**Total Requirements**	**9,023**	**9,151**	**9,256**	**9,361**	**9,576**	**9,579**	**9,754**	**9,923**	**9,934**	**10,082**	**10,565**	**11,011**
E													
M	**Existing Generation**	9,441	9,882	10,037	10,039	10,046	10,052	10,059	10,059	9,974	9,865	9,720	9,694
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							100	475	728	1,003	1,739	2,298
&	Summer Purch $6/Year					48	69	166					
R	Total Resources	10,250	10,640	10,695	10,677	10,726	10,728	10,924	11,113	11,126	11,292	11,833	12,333
	Reserves	1,227	1,489	1,439	1,316	1,150	1,149	1,171	1,190	1,192	1,210	1,268	1,321
	Reserve Margin (RM) (%)	13.6	16.3	15.5	14.1	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with No Turbine Upgrades

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.0	21.7	22.9	23.4	24.3	24.7	24.6	25.0	48.8	71.8	65.4	79.2	449.8
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1													0.0
C	OWC Cogen 2								160.0	160.0				320.0
	OWC Combined Cycle								60.5	77.6	292.8	509.3	379.8	1320.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.0**	**21.7**	**22.9**	**23.4**	**24.3**	**24.7**	**24.6**	**245.5**	**286.4**	**364.6**	**574.7**	**459.0**	**2089.8**
	DSM Programs	14.4	16.6	17.4	17.8	18.0	17.8	17.7	17.6	34.7	52.2	48.7	60.3	333.2
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2												39.0	39.0
T	Utah Combined Cycle											273.8	146.2	420.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4							111.1	187.2	33.0	(0.0)	(0.0)	(0.1)	331.2
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												27.2	27.2
	Total	**14.4**	**16.6**	**17.4**	**17.8**	**18.0**	**17.8**	**128.8**	**204.8**	**67.7**	**52.2**	**322.5**	**272.6**	**1150.6**
	DSM Programs	4.0	4.7	4.8	4.8	4.8	4.9	4.9	4.9	9.7	14.7	13.6	16.9	92.7
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.0**	**4.7**	**4.8**	**4.8**	**4.8**	**4.9**	**4.9**	**4.9**	**9.7**	**14.7**	**13.6**	**16.9**	**92.7**
	DSM Programs	36.4	43.0	45.1	46.0	47.1	47.4	47.2	47.5	93.2	138.7	127.7	156.4	875.7
T	Renewable													0.0
O	Cogeneration													0.0
T	Combined Cycle CT								220.5	237.6	292.8	783.1	565.0	2099.0
A	Coal & IGCC							111.1	187.2	33.0	(0.0)	(0.0)	(0.1)	331.2
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												27.2	27.2
	Total	**36.4**	**43.0**	**45.1**	**46.0**	**47.1**	**47.4**	**158.3**	**455.2**	**363.8**	**431.5**	**910.8**	**748.5**	**3333.1**

Annual Winter Peak Capacity (MW)

S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(36)	(79)	(125)	(171)	(218)	(265)	(312)	(360)	(453)	(592)	(719)	(876)
T	**Total Requirements**	**8,996**	**9,015**	**9,075**	**9,087**	**9,180**	**9,327**	**9,479**	**9,647**	**9,646**	**9,877**	**10,237**	**10,646**
E													
M	Existing Generation	9,385	9,925	10,082	10,087	10,089	10,095	10,102	10,106	10,012	9,898	9,744	9,720
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							111	519	789	1,082	1,865	2,457
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,750	10,912	10,911	10,888	10,869	10,982	11,385	11,120	11,249	11,878	12,446
	Reserves	1,352	1,735	1,838	1,825	1,708	1,542	1,503	1,738	1,474	1,372	1,642	1,800
	Reserve Margin (RM) (%)	15.0	19.2	20.2	20.1	18.6	16.5	15.9	18.0	15.3	13.9	16.0	16.9

Med Load - Med Gas
with No Turbine Upgrades

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.0	19.0	29.4	40.0	50.9	62.0	73.0	84.2	105.9	138.3	168.5	205.5
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal								148.9	297.9	297.9	297.9	297.9
W	OWC Cogen 1								56.3	128.5	400.9	849.1	1,123.4
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.0**	**19.0**	**29.4**	**40.0**	**50.9**	**62.0**	**73.0**	**289.4**	**532.3**	**837.1**	**1,315.4**	**1,626.8**
	DSM Programs	8.5	18.6	29.0	39.7	50.6	61.4	72.1	82.9	104.1	136.4	167.3	205.9
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												36.3
	Utah Cogen 1											252.7	374.5
U	Utah Cogen 2												
T	Utah Combined Cycle							83.3	214.3	242.5	254.5	207.9	156.0
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												2.7
	Utah Pumped Storage												
	Total	**8.5**	**18.6**	**29.0**	**39.7**	**50.6**	**61.4**	**155.4**	**297.2**	**346.7**	**390.9**	**627.9**	**775.3**
	DSM Programs	3.3	7.3	11.3	15.4	19.5	23.6	27.7	31.8	39.9	52.2	64.0	78.6
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**7.3**	**11.3**	**15.4**	**19.5**	**23.6**	**27.7**	**31.8**	**39.9**	**52.2**	**64.0**	**78.6**
	DSM Programs	20.8	45.0	69.7	95.1	121.0	146.9	172.8	198.8	250.0	326.9	399.7	489.9
T	Renewable								205.3	426.4	698.8	1,399.7	1,832.1
O	Cogeneration							83.3	214.3	242.5	254.5	207.9	156.0
T	Combined Cycle CT												
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												2.7
	Pumped Storage												
	Total	**20.8**	**45.0**	**69.7**	**95.1**	**121.0**	**146.9**	**256.2**	**618.4**	**918.9**	**1,280.2**	**2,007.3**	**2,480.7**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	308.5
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	497.7	705.7	760.6	710.3	638.1	589.0	592.1	799.3	957.4	971.2	1,154.4	1,244.7
E	**DSM Programs**	(20.8)	(45.0)	(69.7)	(95.1)	(121.0)	(146.9)	(172.8)	(198.8)	(250.0)	(326.9)	(399.7)	(489.9)
M	**Total Requirements**	7,807.5	8,010.4	8,057.1	8,051.1	8,086.6	8,109.0	8,228.9	8,530.6	8,740.6	8,974.1	9,447.4	9,723.8
	Existing Generation	7,161.2	7,452.8	7,532.6	7,533.7	7,580.5	7,582.4	7,629.5	7,653.9	7,672.2	7,637.5	7,461.2	7,374.5
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	89.3	53.9	51.6	52.7	52.0	81.1	73.8	18.0		1.7		
R	**New Resources**							83.3	419.5	668.9	953.2	1,607.6	1,990.8
	Total Resources	7,807.5	8,010.4	8,057.1	8,051.1	8,086.7	8,109.0	8,228.9	8,530.6	8,740.6	8,974.1	9,447.4	9,723.8

Med Load - Med Gas
with No Turbine Upgrades

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	21	45	69	95	120	146	172	198	250	328	400	495
			After Conservation												
			System Load (MWa)	5,703	5,682	5,725	5,811	5,938	6,034	6,151	6,280	6,522	6,914	7,261	7,647
	0.52		Energy Sales (MWa)	5,154	5,161	5,221	5,312	5,414	5,519	5,627	5,736	5,904	6,145	6,469	6,621
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,079	8,307	8,495	8,714	8,959	9,434	9,929	10,270	10,863	11,816	13,469	15,375
			Net Conservation Assets ($M)	47	98	151	187	221	253	283	312	362	418	444	490
			Utility Cost												
42,610	3.27	Nominal	**Operating Revenues ($M)**	2,211	2,201	2,246	2,339	2,443	2,568	2,631	2,671	2,955	3,379	3,894	4,535
	-0.03	Real		2,211	2,130	2,105	2,122	2,145	2,184	2,165	2,128	2,206	2,289	2,393	2,447
	2.73	Nominal	Cost in mills/kWh	49.0	48.7	49.1	50.3	51.5	53.1	53.4	53.2	57.1	62.8	68.7	78.2
	-0.55	Real		49.0	47.1	46.0	45.6	45.2	45.2	43.9	42.4	42.7	42.5	42.2	42.2
		Nominal	Average Customer Bill ($)	1,668	1,643	1,655	1,695	1,738	1,798	1,812	1,809	1,938	2,113	2,335	2,649
		Real		1,668	1,590	1,551	1,538	1,527	1,529	1,491	1,441	1,447	1,431	1,435	1,430
			Total Resource Cost												
			DSR Customer Cost ($M)	0.9	1.7	2.5	5.1	7.4	9.4	11.0	12.3	12.7	7.7	-2.5	-27.2
			Levelized (20-year at 8.6%)	0.1	0.3	0.5	1.1	1.9	2.9	4.0	5.4	8.1	11.3	11.9	11.9
			Energy Svc Charge ($M)	4.0	8.7	13.7	16.9	20.2	23.6	27.0	30.6	38.1	50.0	58.8	61.4
43,052	3.27	Nominal	**Total Resource Cost ($M)**	2,216	2,210	2,260	2,357	2,465	2,595	2,662	2,707	3,001	3,440	3,965	4,608
	-0.03	Real		2,216	2,139	2,118	2,138	2,164	2,206	2,190	2,156	2,241	2,330	2,436	2,487
	2.59	Nominal	Cost in mills/kWh	48.9	48.5	48.8	49.8	50.9	52.4	52.5	52.2	55.9	60.9	66.2	74.4
	-0.68	Real		48.9	46.9	45.8	45.2	44.7	44.6	43.2	41.6	41.7	41.3	40.7	40.1

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.64**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.12**

Med Load - Med Gas
with No Turbine Upgrades

Net System Projected Emissions

	Annual Growth Rate	1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
System Energy													
GWh		49,967	49,775	50,145	50,871	51,981	52,823	53,847	54,983	57,095	60,532	67,020	66,721
MWa		5,704	5,682	5,724	5,807	5,934	6,030	6,147	6,277	6,518	6,910	7,651	7,617
Total Annual Emissions (1000 Tons)													
CO2	0.00%	51,946	51,574	51,704	52,028	52,732	53,057	53,476	53,839	54,859	56,659	58,366	51,970
NOx	0.09%	121.1	120.3	120.5	120.5	121.3	121.2	123.9	123.4	123.7	123.9	124.0	123.3
TSP	0.14%	10.9	10.8	10.8	10.8	10.9	10.9	10.9	10.9	11.0	11.0	11.1	11.2
Annual System Emission Rates (Pounds/MWh)													
CO2	-1.51%	2,079	2,072	2,062	2,045	2,029	2,009	1,986	1,958	1,922	1,872	1,742	1,558
NOx	-1.42%	4.85	4.83	4.81	4.74	4.67	4.59	4.60	4.49	4.33	4.09	3.70	3.70
TSP	-1.38%	0.43	0.43	0.43	0.42	0.42	0.41	0.41	0.40	0.38	0.36	0.33	0.33
Emission Rates as Percent of 1994 Base													
CO2		100	99.67	99.18	98.38	97.58	96.62	95.53	94.19	92.42	90.04	83.77	74.92
NOx		100	99.68	99.13	97.72	96.24	94.65	94.92	92.56	89.35	84.42	76.34	76.22
TSP		100	99.60	99.06	97.70	96.17	94.74	93.21	91.38	88.46	83.92	76.09	76.86

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,430	1,088,608
NOx	122.9	2,457
TSP	11.0	220

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Med Load - Med Gas without Hermiston

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
OWC	DSM Programs	14.2	15.6	16.1	16.4	16.9	17.1	17.0	17.1	33.5	49.6	46.0	56.5	316.0
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
	OWC Geothermal							150.4	150.4					300.8
	OWC Cogen 1								233.7	180.1	274.7	552.3		1240.8
	OWC Cogen 2												291.0	291.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.2**	**15.6**	**16.1**	**16.4**	**16.9**	**17.1**	**167.4**	**401.2**	**213.6**	**324.3**	**598.3**	**347.5**	**2148.6**
UTAH	DSM Programs	12.1	13.9	14.3	14.7	14.8	14.8	14.6	14.8	28.9	44.0	41.8	52.0	280.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal												36.7	36.7
	Utah Cogen 1											183.4	211.4	394.8
	Utah Cogen 2													0.0
	Utah Combined Cycle							56.6	168.0	72.6	(0.0)	(0.0)	0.1	297.3
	Utah Gadsby Repower													0.0
	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air												18.6	18.6
	Utah Pumped Storage													0.0
	Total	**12.1**	**13.9**	**14.3**	**14.7**	**14.8**	**14.8**	**71.2**	**182.8**	**101.5**	**44.0**	**225.2**	**318.8**	**1028.1**
WYOMING	DSM Programs	4.5	5.1	5.2	5.3	5.5	5.4	5.4	5.5	10.7	16.2	15.5	19.1	103.4
	Wyo Wind Non-firm													0.0
	Wyo Wind Firm													0.0
	Wyo Combined Cycle													0.0
	Wyo IGCC Wyodak 2													0.0
	Wyo IGCC CT													0.0
	Wyo PC Wyodak 2													0.0
	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.5**	**5.1**	**5.2**	**5.3**	**5.5**	**5.4**	**5.4**	**5.5**	**10.7**	**16.2**	**15.5**	**19.1**	**103.4**
TOTAL	DSM Programs	30.8	34.6	35.6	36.4	37.2	37.3	37.0	37.4	73.1	109.8	103.3	127.6	700.1
	Renewable							150.4	384.1	180.1	274.7	735.7	248.1	1973.1
	Cogeneration							56.6	168.0	72.6	(0.0)	(0.0)	291.1	588.3
	Combined Cycle CT													0.0
	Coal & IGCC													0.0
	Transmission													0.0
	Simple Cycle CT												18.6	18.6
	Pumped Storage													0.0
	Total	**30.8**	**34.6**	**35.6**	**36.4**	**37.2**	**37.3**	**244.0**	**589.5**	**325.8**	**384.5**	**839.0**	**685.4**	**3280.1**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(31)	(65)	(101)	(137)	(175)	(212)	(249)	(286)	(359)	(469)	(573)	(700)
T	**Total Requirements**	**9,023**	**9,151**	**9,256**	**9,361**	**9,575**	**9,578**	**9,753**	**9,922**	**9,933**	**10,081**	**10,564**	**11,009**
E													
M	Existing Generation	9,441	9,549	9,712	9,736	9,751	9,767	9,774	9,774	9,689	9,580	9,435	9,409
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							207	759	1,012	1,287	2,022	2,580
&	Summer Purch $6/Year				110	342	354	343					
R	**Total Resources**	**10,250**	**10,307**	**10,370**	**10,484**	**10,725**	**10,728**	**10,924**	**11,112**	**11,125**	**11,290**	**11,831**	**12,330**
	Reserves	1,227	1,156	1,114	1,123	1,150	1,150	1,171	1,190	1,192	1,210	1,268	1,321
	Reserve Margin (RM) (%)	13.6	12.6	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
without Hermiston

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.3	21.7	22.9	23.5	24.4	24.8	24.7	25.0	48.8	71.9	65.3	79.1	450.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1													0.0
C	OWC Cogen 2							160.0	160.0					320.0
	OWC Combined Cycle								248.6	191.6	292.2	587.6		1320.0
	OWC Bridger Trans L												309.6	309.6
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.3**	**21.7**	**22.9**	**23.5**	**24.4**	**24.8**	**184.7**	**433.6**	**240.4**	**364.1**	**652.9**	**388.7**	**2400.0**
	DSM Programs	14.4	16.6	17.4	17.8	18.0	17.8	17.7	17.6	34.7	52.2	48.7	60.3	333.2
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2												39.0	39.0
T	Utah Combined Cycle											195.1	224.9	420.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4							63.1	187.2	80.8	(0.0)	(0.0)	0.1	331.2
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												18.6	18.6
	Total	**14.4**	**16.6**	**17.4**	**17.8**	**18.0**	**17.8**	**80.8**	**204.8**	**115.5**	**52.2**	**243.8**	**342.9**	**1142.0**
	DSM Programs	4.0	4.7	4.8	4.9	5.0	5.0	5.0	5.1	9.9	15.1	14.0	17.4	94.9
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.0**	**4.7**	**4.8**	**4.9**	**5.0**	**5.0**	**5.0**	**5.1**	**9.9**	**15.1**	**14.0**	**17.4**	**94.9**
	DSM Programs	36.7	43.0	45.1	46.2	47.4	47.6	47.4	47.7	93.4	139.2	128.0	156.8	878.5
T	Renewable													0.0
O	Cogeneration													0.0
T	Combined Cycle CT							160.0	408.6	191.6	292.2	782.7	263.9	2099.0
A	Coal & IGCC							63.1	187.2	80.8	(0.0)	(0.0)	309.7	640.8
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												18.6	18.6
	Total	**36.7**	**43.0**	**45.1**	**46.2**	**47.4**	**47.6**	**270.5**	**643.5**	**365.8**	**431.4**	**910.7**	**749.0**	**3636.9**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(37)	(80)	(125)	(171)	(218)	(266)	(313)	(361)	(455)	(594)	(722)	(879)
T	**Total Requirements**	**8,995**	**9,014**	**9,074**	**9,086**	**9,180**	**9,326**	**9,478**	**9,646**	**9,645**	**9,875**	**10,234**	**10,644**
E													
M	Existing Generation	9,385	9,533	9,698	9,725	9,735	9,752	9,759	9,763	9,669	9,555	9,401	9,377
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							223	819	1,091	1,384	2,166	2,758
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,358**	**10,528**	**10,549**	**10,534**	**10,526**	**10,751**	**11,342**	**11,079**	**11,207**	**11,836**	**12,404**
	Reserves	1,353	1,344	1,454	1,463	1,354	1,200	1,273	1,697	1,435	1,332	1,602	1,761
	Reserve Margin (RM) (%)	15.0	14.9	16.0	16.1	14.8	12.9	13.4	17.6	14.9	13.5	15.6	16.5

PacifiCorp RAMPP-4

Case # 6

Med Load - Med Gas
without Hermiston

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.1	19.2	29.6	40.2	51.1	62.2	73.3	84.4	106.2	138.6	168.7	205.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal							148.9	297.9	297.9	297.9	297.9	297.9
W	OWC Cogen 1								231.3	409.6	679.9	1,196.4	1,205.0
C	OWC Cogen 2												130.6
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.1**	**19.2**	**29.6**	**40.2**	**51.1**	**62.2**	**222.2**	**613.6**	**813.6**	**1,116.4**	**1,663.0**	**1,839.1**
	DSM Programs	8.5	18.6	29.0	39.7	50.6	61.4	72.1	82.9	104.1	136.4	167.3	205.9
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												36.3
	Utah Cogen 1											178.9	368.6
U	Utah Cogen 2												
T	Utah Combined Cycle							46.9	171.9	232.8	248.4	209.0	198.3
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												1.3
	Utah Pumped Storage												
	Total	**8.5**	**18.6**	**29.0**	**39.7**	**50.6**	**61.4**	**119.0**	**254.8**	**336.9**	**384.8**	**555.2**	**810.4**
	DSM Programs	3.3	7.3	11.3	15.5	19.7	24.0	28.2	32.5	40.8	53.5	65.7	80.8
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**7.3**	**11.3**	**15.5**	**19.7**	**24.0**	**28.2**	**32.5**	**40.8**	**53.5**	**65.7**	**80.8**
	DSM Programs	20.9	45.1	69.9	95.4	121.4	147.6	173.6	199.8	251.2	328.6	401.7	492.4
T	Renewable							148.9	529.2	707.4	977.8	1,673.1	1,907.8
O	Cogeneration							46.9	171.9	232.8	248.4	209.0	328.9
T	Combined Cycle CT												
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												1.3
	Pumped Storage												
	Total	**20.9**	**45.1**	**69.9**	**95.4**	**121.4**	**147.6**	**369.5**	**900.9**	**1,191.4**	**1,554.7**	**2,283.8**	**2,730.4**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	306.9	307.0	307.0	305.0	305.0	305.0	306.8
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	408.6	403.1	485.8	463.1	414.9	374.8	424.6	761.8	914.2	941.6	1,145.5	1,243.9
E	**DSM Programs**	(20.9)	(45.1)	(69.9)	(95.4)	(121.4)	(147.6)	(173.6)	(199.8)	(251.2)	(328.5)	(401.7)	(492.4)
M	**Total Requirements**	7,718.3	7,707.7	7,782.2	7,803.6	7,863.0	7,894.2	8,060.6	8,492.1	8,696.1	8,943.0	9,436.6	9,718.8
	Existing Generation	7,053.3	7,093.1	7,210.7	7,216.9	7,263.7	7,284.4	7,311.1	7,316.0	7,351.0	7,323.9	7,175.8	7,122.2
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	108.0	110.9	98.6	122.0	145.2	164.2	111.5	35.9	5.4	11.1		
R	**New Resources**							195.8	701.1	940.2	1,226.2	1,882.2	2,238.0
	Total Resources	7,718.3	7,707.7	7,782.2	7,803.6	7,863.0	7,894.2	8,060.6	8,492.1	8,696.1	8,942.9	9,436.6	9,718.7

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Case # 6

Med Load - Med Gas
without Hermiston

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	21	45	69	95	121	147	173	199	252	329	402	498
			After Conservation												
			System Load (MWa)	5,703	5,682	5,725	5,810	5,937	6,033	6,150	6,279	6,521	6,913	7,259	7,644
	0.52		Energy Sales (MWa)	5,154	5,161	5,221	5,312	5,413	5,518	5,626	5,735	5,903	6,143	6,467	6,619
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	7,787	7,994	8,188	8,413	8,744	9,406	9,996	10,287	10,805	11,722	13,324	15,145
			Net Conservation Assets ($M)	47	99	151	187	221	254	284	313	364	419	446	492
			Utility Cost												
43,273	3.29	Nominal	**Operating Revenues ($M)**	2,219	2,214	2,261	2,366	2,490	2,619	2,685	2,741	3,041	3,454	3,965	4,595
	-0.01	Real		2,219	2,143	2,119	2,146	2,186	2,226	2,210	2,184	2,271	2,340	2,437	2,480
	2.75	Nominal	Cost in mills/kWh	49.2	49.0	49.4	50.8	52.5	54.2	54.5	54.6	58.8	64.2	70.0	79.3
	-0.53	Real		49.2	47.4	46.3	46.1	46.1	46.1	44.8	43.5	43.9	43.5	43.0	42.8
		Nominal	Average Customer Bill ($)	1,673	1,653	1,666	1,715	1,772	1,834	1,850	1,857	1,995	2,160	2,378	2,684
		Real		1,673	1,600	1,561	1,556	1,556	1,559	1,522	1,479	1,489	1,463	1,461	1,449
			Total Resource Cost												
			DSR Customer Cost ($M)	0.6	1.6	2.5	5.1	7.5	9.4	11.1	12.3	12.8	7.9	-2.3	-27.0
			Levelized (20-year at 8.6%)	0.1	0.2	0.5	1.0	1.8	2.8	4.0	5.3	8.1	11.3	12.0	12.0
			Energy Svc Charge ($M)	4.0	8.7	13.7	16.9	20.2	23.6	27.1	30.7	38.2	50.2	59.1	61.8
43,716	3.28	Nominal	**Total Resource Cost ($M)**	2,223	2,223	2,275	2,384	2,512	2,645	2,716	2,777	3,088	3,516	4,037	4,669
	-0.01	Real		2,223	2,152	2,132	2,162	2,206	2,249	2,236	2,212	2,305	2,381	2,480	2,519
	2.61	Nominal	Cost in mills/kWh	49.1	48.8	49.1	50.4	51.9	53.4	53.6	53.6	57.5	62.3	67.4	75.3
	-0.67	Real		49.1	47.2	46.1	45.7	45.6	45.4	44.1	42.7	42.9	42.2	41.4	40.7

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.31

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.76

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Med Load - Med Gas
without Hermiston

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,966	49,775	50,144	50,869	51,977	52,818	53,840	54,974	57,084	60,518	66,983	66,682
	MWa	5,704	5,682	5,724	5,807	5,933	6,029	6,146	6,276	6,516	6,908	7,646	7,612
	Total Annual Emissions (1000 Tons)												
-0.02%	CO_2	52,020	52,197	52,425	52,838	53,557	53,975	54,393	54,683	55,685	57,526	59,257	51,780
0.19%	NO_x	121.3	121.8	122.4	122.7	123.5	123.8	126.6	125.8	126.0	126.3	126.6	125.7
0.25%	TSP	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.1	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.53%	CO_2	2,082	2,097	2,091	2,077	2,061	2,044	2,021	1,989	1,951	1,901	1,769	1,553
-1.32%	NO_x	4.85	4.90	4.88	4.82	4.75	4.69	4.70	4.58	4.41	4.18	3.78	3.77
-1.27%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO_2	100	100.73	100.42	99.77	98.97	98.16	97.04	95.54	93.70	91.30	84.97	74.59
	NO_x	100	100.88	100.56	99.40	97.94	96.57	96.86	94.28	90.94	86.02	77.88	77.70
	TSP	100	100.76	100.54	99.46	97.98	96.76	95.11	93.04	90.10	85.59	77.70	78.51

20 Year Emissions (1000 Tons)	Average	Total
CO_2	55,104	1,102,072
NO_x	125.1	2,502
TSP	11.2	224

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Med Load - High Gas without Hermiston

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	20.7	21.2	21.3	21.3	21.4	41.8	62.5	58.9	73.2	388.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1							150.4	150.4					300.8
C	OWC Cogen 2								424.8	222.9	220.0	373.1		1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.3**	**15.7**	**16.1**	**20.7**	**21.2**	**21.3**	**171.7**	**596.6**	**264.7**	**282.5**	**432.0**	**73.2**	**1930.0**
	DSM Programs	13.4	14.2	14.6	14.7	14.9	14.7	14.7	14.7	29.0	44.0	41.7	51.9	282.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1										36.7			36.7
	Utah Cogen 2									17.6		178.3		195.9
U	Utah Combined Cycle													0.0
T	Utah Gadsby Repower													0.0
A	Utah IGCC Hunter 4													0.0
H	Utah IGCC CT													0.0
	Utah PC Hunter 4											166.3	233.7	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												36.7	36.7
	Total	13.4	14.2	14.6	14.7	14.9	14.7	14.7	14.7	46.6	80.7	386.3	322.3	951.8
	DSM Programs	5.1	5.2	5.4	6.4	6.6	6.5	6.6	6.5	13.0	19.6	18.8	23.4	123.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												264.0	264.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	5.1	5.2	5.4	6.4	6.6	6.5	6.6	6.5	13.0	19.6	18.8	287.4	387.1
	DSM Programs	32.8	35.1	36.1	41.8	42.7	42.5	42.6	42.6	83.8	126.1	119.4	148.5	794.0
T	Renewable													0.0
O	Cogeneration							150.4	575.2	240.5	256.7	551.4		1774.2
T	Combined Cycle CT													0.0
A	Coal & IGCC											166.3	497.7	664.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												36.7	36.7
	Total	32.8	35.1	36.1	41.8	42.7	42.5	193.0	617.8	324.3	382.8	837.1	682.9	3268.9

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(68)	(104)	(146)	(189)	(231)	(274)	(316)	(400)	(526)	(646)	(794)
T	**Total Requirements**	9,021	9,148	9,253	9,352	9,562	9,559	9,728	9,892	9,892	10,024	10,491	10,915
E													
M	Existing Generation	9,441	9,549	9,712	9,736	9,751	9,767	9,774	9,774	9,689	9,580	9,435	9,409
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							150	726	966	1,223	1,941	2,475
&	Summer Purch $6/Year				101	327	332	372					
R	Total Resources	10,250	10,307	10,370	10,475	10,710	10,706	10,896	11,079	11,079	11,227	11,750	12,225
	Reserves	1,229	1,159	1,117	1,123	1,149	1,147	1,168	1,187	1,187	1,203	1,259	1,310
	Reserve Margin (RM) (%)	13.6	12.7	12.1	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Case # 7

Med Load - High Gas
without Hermiston

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	27.0	27.8	28.3	28.1	28.5	55.6	82.3	75.7	92.7	509.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1							160.0	160.0					320.0
C	OWC Cogen 2								451.9	237.2	234.0	396.9		1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	18.4	21.8	22.9	27.0	27.8	28.3	188.1	640.4	292.8	316.3	472.6	92.7	2149.1
	DSM Programs	15.7	16.9	17.7	17.8	18.0	17.9	17.6	17.8	34.8	52.5	49.1	60.6	336.4
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1										39.0			39.0
U	Utah Cogen 2									18.8		189.6		208.4
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											166.3	233.7	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												36.7	36.7
	Total	15.7	16.9	17.7	17.8	18.0	17.9	17.6	17.8	53.6	91.5	405.0	331.0	1020.5
	DSM Programs	4.6	4.8	4.9	5.5	5.6	5.6	5.8	5.8	11.5	18.0	17.4	22.3	111.8
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												264.0	264.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.6	4.8	4.9	5.5	5.6	5.6	5.8	5.8	11.5	18.0	17.4	286.3	375.8
	DSM Programs	38.7	43.5	45.5	50.3	51.4	51.8	51.5	52.1	101.9	152.8	142.2	175.6	957.3
T	Renewable													0.0
O	Cogeneration							160.0	611.9	256.0	273.0	586.5		1887.4
T	Combined Cycle CT													0.0
A	Coal & IGCC											166.3	497.7	664.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												36.7	36.7
	Total	38.7	43.5	45.5	50.3	51.4	51.8	211.5	664.0	357.9	425.8	895.0	710.0	3545.4

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(82)	(128)	(178)	(229)	(281)	(333)	(385)	(487)	(640)	(782)	(957)
T	Total Requirements	8,993	9,012	9,071	9,079	9,169	9,311	9,458	9,622	9,612	9,830	10,174	10,565
E													
M	Existing Generation	9,385	9,533	9,698	9,725	9,735	9,752	9,759	9,763	9,669	9,555	9,401	9,377
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							160	772	1,028	1,301	2,054	2,588
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,358	10,528	10,549	10,534	10,526	10,688	11,296	11,016	11,125	11,724	12,234
	Reserves	1,355	1,346	1,457	1,470	1,365	1,215	1,230	1,674	1,404	1,295	1,549	1,669
	Reserve Margin (RM) (%)	15.1	14.9	16.1	16.2	14.9	13.0	13.0	17.4	14.6	13.2	15.2	15.8

PacifiCorp RAMPP-4

Case # 7

Med Load - High Gas
without Hermiston

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	42.4	55.4	68.6	81.7	94.9	120.7	159.3	195.6	240.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal							148.9	297.9	297.9	297.9	297.9	297.9
W	OWC Cogen 1								418.4	637.5	843.0	1,147.7	1,104.4
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.3**	**19.3**	**29.7**	**42.4**	**55.4**	**68.6**	**230.6**	**811.1**	**1,056.1**	**1,300.2**	**1,641.2**	**1,642.9**
	DSM Programs	9.8	20.2	30.9	41.7	52.5	63.3	74.1	84.9	106.2	138.6	169.6	208.2
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal										36.3	36.3	34.9
	Utah Cogen 1									15.9	16.4	176.5	167.9
U	Utah Cogen 2												
T	Utah Combined Cycle												
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT											152.4	366.6
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												6.2
	Utah Pumped Storage												
	Total	**9.8**	**20.2**	**30.9**	**41.7**	**52.5**	**63.3**	**74.1**	**84.9**	**122.1**	**191.3**	**534.7**	**783.7**
	DSM Programs	3.9	8.1	12.2	16.9	21.6	26.4	31.2	36.0	45.5	60.2	74.4	92.5
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												241.9
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.9**	**8.1**	**12.2**	**16.9**	**21.6**	**26.4**	**31.2**	**36.0**	**45.5**	**60.2**	**74.4**	**334.4**
	DSM Programs	23.0	47.6	72.8	101.0	129.6	158.2	186.9	215.7	272.4	358.1	439.6	541.3
T	Renewable							148.9	716.2	951.2	1,193.6	1,658.4	1,605.0
O	Cogeneration												
T	Combined Cycle CT											152.4	608.5
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												6.2
	Pumped Storage												
	Total	**23.0**	**47.6**	**72.8**	**101.0**	**129.6**	**158.2**	**335.9**	**932.0**	**1,223.7**	**1,551.6**	**2,250.3**	**2,761.0**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	308.3	309.8	307.2	306.9	306.5	307.0	307.0	299.1	305.0	305.0	312.9
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	428.7	419.0	507.4	474.8	431.8	388.7	428.3	788.1	930.8	928.7	1,116.6	1,240.7
E	**DSM Programs**	(23.0)	(47.6)	(72.8)	(101.0)	(129.5)	(158.2)	(186.9)	(215.7)	(272.4)	(358.1)	(439.6)	(541.3)
M	**Total Requirements**	7,736.3	7,719.3	7,800.8	7,809.8	7,871.7	7,896.9	8,051.0	8,502.4	8,685.5	8,900.5	9,369.7	9,672.8
	Existing Generation	7,053.0	7,099.9	7,214.1	7,224.6	7,279.2	7,295.3	7,311.1	7,314.3	7,313.0	7,301.8	7,180.1	7,094.6
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	126.3	115.7	113.8	120.5	138.4	156.0	148.7	32.8	21.8	23.4	0.3	
R	**New Resources**							148.9	716.2	951.2	1,193.6	1,810.7	2,219.7
	Total Resources	7,736.3	7,719.3	7,800.8	7,809.8	7,871.7	7,896.9	8,051.0	8,502.4	8,685.5	8,900.5	9,369.7	9,672.8

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Case # 7

Med Load - High Gas
without Hermiston

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	47	72	100	129	158	186	215	273	360	441	548
			After Conservation												
			System Load (MWa)	5,701	5,680	5,722	5,805	5,929	6,022	6,136	6,263	6,499	6,882	7,220	7,594
	0.51		Energy Sales (MWa)	5,152	5,159	5,219	5,307	5,406	5,508	5,614	5,720	5,883	6,116	6,432	6,573
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	7,791	7,999	8,194	8,420	8,725	9,344	9,939	10,225	10,758	11,844	13,758	16,196
			Net Conservation Assets ($M)	51	103	157	198	237	275	311	345	408	480	520	581
			Utility Cost												
43,620	3.27	Nominal	Operating Revenues ($M)	2,218	2,213	2,259	2,362	2,484	2,611	2,702	2,797	3,127	3,551	4,030	4,561
	-0.03	Real		2,218	2,142	2,117	2,142	2,181	2,220	2,223	2,229	2,335	2,405	2,477	2,461
	2.75	Nominal	Cost in mills/kWh	49.2	49.0	49.4	50.8	52.5	54.1	54.9	55.8	60.7	66.3	71.5	79.2
	-0.54	Real		49.2	47.4	46.3	46.1	46.1	46.0	45.2	44.5	45.3	44.9	44.0	42.8
		Nominal	Average Customer Bill ($)	1,673	1,652	1,664	1,712	1,768	1,828	1,861	1,895	2,051	2,221	2,417	2,664
		Real		1,673	1,599	1,560	1,553	1,553	1,554	1,532	1,510	1,531	1,504	1,485	1,438
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.7	6.1	9.1	11.9	14.0	15.9	18.0	16.3	9.9	-8.5
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.2	2.2	3.4	4.9	6.6	10.4	15.9	19.9	20.8
			Energy Svc Charge ($M)	4.5	9.3	14.4	18.2	22.1	26.2	30.4	34.7	43.7	58.1	69.1	74.2
44,158	3.26	Nominal	Total Resource Cost ($M)	2,223	2,223	2,274	2,381	2,508	2,641	2,737	2,839	3,181	3,625	4,119	4,656
	-0.04	Real		2,223	2,152	2,131	2,160	2,203	2,245	2,252	2,262	2,375	2,456	2,531	2,513
	2.59	Nominal	Cost in mills/kWh	49.1	48.8	49.1	50.3	51.8	53.3	54.0	54.8	59.2	64.2	68.8	75.1
	-0.69	Real		49.1	47.2	46.0	45.7	45.5	45.3	44.5	43.6	44.2	43.5	42.3	40.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.86

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 42.18

Med Load - High Gas
without Hermiston

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,948	49,736	50,118	50,820	51,906	52,720	53,724	54,834	56,846	60,260	66,608	66,067
	MWa	5,702	5,678	5,721	5,801	5,925	6,018	6,133	6,260	6,489	6,879	7,604	7,542
	Total Annual Emissions (1000 Tons)												
0.03%	CO2	52,010	52,240	52,409	52,825	53,579	53,993	54,463	54,944	55,879	57,764	60,183	52,278
0.21%	NOx	121.2	122.0	122.3	122.7	123.7	124.0	127.0	127.1	127.2	127.8	130.8	126.2
0.38%	TSP	10.9	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.4	11.7
	Annual System Emission Rates (Pounds/MWh)												
-1.43%	CO2	2,083	2,101	2,091	2,079	2,064	2,048	2,028	2,004	1,966	1,917	1,807	1,583
-1.25%	NOx	4.85	4.91	4.88	4.83	4.77	4.70	4.73	4.63	4.47	4.24	3.93	3.82
-1.09%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.42	0.41	0.39	0.38	0.34	0.35
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.87	100.42	99.82	99.13	98.35	97.36	96.23	94.40	92.06	86.77	75.99
	NOx	100	101.06	100.56	99.48	98.17	96.87	97.39	95.46	92.16	87.38	80.87	78.67
	TSP	100	100.98	100.54	99.54	98.24	97.09	95.54	93.75	90.65	86.24	78.84	81.25

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,413	1,108,259
NOx	126.4	2,528
TSP	11.3	225

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Med Load - Med Gas
with No DSM

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs													0.0
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal								150.4	150.4				300.8
W	OWC Cogen 1								206.6	110.2	290.0	629.7	4.3	1240.8
C	OWC Cogen 2												495.7	495.7
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													
	Total								357.0	260.6	290.0	629.7	500.0	2037.3
	DSM Programs													0.0
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal												36.7	36.7
	Utah Cogen 1									65.2	107.9	221.7		394.8
U	Utah Cogen 2													0.0
T	Utah Combined Cycle							120.7	168.0	8.6	(0.0)	(0.0)	(0.0)	297.3
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air												164.0	164.0
	Utah Pumped Storage													
	Total							120.7	168.0	73.8	107.9	221.7	200.7	892.8
	DSM Programs													0.0
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													
	Total													
	DSM Programs													0.0
T	Renewable													0.0
O	Cogeneration								357.0	325.8	397.9	851.4	41.0	1973.1
T	Combined Cycle CT							120.7	168.0	8.6	(0.0)	(0.0)	495.7	793.0
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												164.0	164.0
	Total							120.7	525.0	334.4	397.9	851.4	700.7	2930.1

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs												
T	**Total Requirements**	9,054	9,216	9,357	9,498	9,750	9,790	10,002	10,208	10,292	10,550	11,136	11,709
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,207	10,207	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							121	646	980	1,378	2,229	2,930
&	Summer Purch $6/Year					104	157	274					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,921	10,965	11,202	11,432	11,527	11,816	12,472	13,114
	Reserves	1,196	1,525	1,447	1,310	1,171	1,175	1,200	1,224	1,235	1,266	1,336	1,405
	Reserve Margin (RM) (%)	13.2	16.5	15.5	13.8	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Case # 11

Med Load - Med Gas
with No DSM

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs													
	OWC Wind Non-Firm													
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1													0.0
C	OWC Cogen 2								160.0	160.0				320.0
	OWC Combined Cycle								219.8	117.2	308.6	669.9	4.5	1320.0
	OWC Bridger Trans L												527.4	527.4
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
														0.0
	Total								379.8	277.2	308.6	669.9	531.9	2167.4
	DSM Programs													
	Utah Wind Non-firm													
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2												39.0	39.0
T	Utah Combined Cycle									69.4	114.7	235.9		420.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4							134.5	187.2	9.6	(0.0)	(0.0)	(0.1)	331.2
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
													164.0	164.0
	Total							134.5	187.2	79.0	114.7	235.9	202.9	954.2
	DSM Programs													
W	Wyo Wind Non-firm													
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total													0.0
	DSM Programs													
T	Renewable													0.0
O	Cogeneration													0.0
T	Combined Cycle CT								379.8	346.6	423.3	905.8	43.5	2099.0
A	Coal & IGCC							134.5	187.2	9.6	(0.0)	(0.0)	527.3	858.6
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
													164.0	164.0
	Total							134.5	567.0	356.2	423.3	905.8	734.8	3121.6

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs												
T	Total Requirements	9,032	9,094	9,199	9,257	9,398	9,592	9,791	10,007	10,099	10,469	10,956	11,522
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,250	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							135	702	1,058	1,481	2,387	3,122
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,850	11,020	11,041	11,026	11,018	11,154	11,718	11,538	11,797	12,549	13,260
	Reserves	1,316	1,756	1,821	1,784	1,628	1,426	1,363	1,711	1,439	1,328	1,593	1,738
	Reserve Margin (RM) (%)	14.6	19.3	19.8	19.3	17.3	14.9	13.9	17.1	14.2	12.7	14.5	15.1

Med Load - Med Gas
with No DSM

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs												
	OWC Wind Non-Firm												
	OWC Wind Firm								148.9	297.9	297.9	297.9	297.9
O	OWC Geothermal								204.5	313.6	591.6	1,130.8	1,187.8
W	OWC Cogen 1												211.0
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total								353.5	611.5	889.4	1,428.7	1,696.6
	DSM Programs												
	Utah Wind Non-firm												
	Utah Wind Firm												36.3
	Utah Geothermal									64.6	171.3	371.9	390.8
	Utah Cogen 1												
U	Utah Cogen 2							100.9	224.3	216.7	228.6	152.5	193.9
T	Utah Combined Cycle												
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												14.8
	Utah Compressed Air												
	Utah Pumped Storage												
	Total							100.9	224.3	281.3	399.9	524.4	635.8
	DSM Programs												
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total												
	DSM Programs												
T	Renewable								353.5	676.1	1,060.7	1,800.6	1,912.7
O	Cogeneration							100.9	224.3	216.7	228.6	152.5	404.9
T	Combined Cycle CT												
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												14.8
	Pumped Storage												
	Total							100.9	577.8	892.7	1,289.3	1,953.0	2,332.4
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	324.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	482.2	725.2	764.6	709.8	643.4	577.9	564.6	850.3	1,019.7	1,064.8	1,177.0	1,243.7
E	**DSM Programs**												
M	**Total Requirements**	7,812.8	8,074.9	8,130.8	8,145.7	8,212.9	8,244.8	8,374.2	8,780.4	9,052.8	9,394.7	9,869.8	10,228.3
	Existing Generation	7,162.2	7,522.4	7,606.9	7,634.7	7,695.9	7,707.3	7,757.2	7,763.4	7,760.4	7,721.0	7,538.1	7,537.4
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	93.5	48.7	51.0	46.3	62.9	92.0	73.8	0.1	0.1	2.7		
R	**New Resources**							100.9	577.8	892.7	1,289.3	1,953.0	2,332.4
	Total Resources	7,812.8	8,074.9	8,130.8	8,145.7	8,212.9	8,244.8	8,374.2	8,780.4	9,052.8	9,394.7	9,869.8	10,228.2

Case # 11

Med Load - Med Gas
with No DSM

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	0	0	0	0	0	0	0	0	0	0	0	0
			After Conservation												
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
	0.66		Energy Sales (MWa)	5,173	5,202	5,285	5,399	5,524	5,653	5,785	5,918	6,134	6,446	6,836	7,076
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,033	8,181	8,315	8,489	8,718	9,243	9,803	10,151	10,745	11,793	13,523	15,404
			Net Conservation Assets ($M)	0	0	0	0	0	0	0	0	0	0	0	0
			Utility Cost												
43,471	3.34	Nominal	Operating Revenues ($M)	2,215	2,201	2,242	2,331	2,440	2,571	2,631	2,669	2,998	3,446	4,021	4,689
	0.04	Real		2,215	2,131	2,101	2,115	2,143	2,185	2,165	2,127	2,239	2,334	2,471	2,530
	2.66	Nominal	Cost in mills/kWh	48.9	48.3	48.4	49.3	50.4	51.9	51.9	51.5	55.8	61.0	67.2	75.7
	-0.62	Real		48.9	46.8	45.4	44.7	44.3	44.1	42.7	41.0	41.7	41.3	41.3	40.8
		Nominal	Average Customer Bill ($)	1,671	1,643	1,651	1,690	1,737	1,800	1,812	1,808	1,967	2,155	2,412	2,739
		Real		1,671	1,591	1,548	1,533	1,525	1,530	1,491	1,441	1,468	1,460	1,482	1,478
			Total Resource Cost												
			DSR Customer Cost ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			Levelized (20-year at 8.6%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			Energy Svc Charge ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43,471	3.34	Nominal	Total Resource Cost ($M)	2,215	2,201	2,242	2,331	2,440	2,571	2,631	2,669	2,998	3,446	4,021	4,689
	0.04	Real		2,215	2,131	2,101	2,115	2,143	2,185	2,165	2,127	2,239	2,334	2,471	2,530
	2.66	Nominal	Cost in mills/kWh	48.9	48.3	48.4	49.3	50.4	51.9	51.9	51.5	55.8	61.0	67.2	75.7
	-0.62	Real		48.9	46.8	45.4	44.7	44.3	44.1	42.7	41.0	41.7	41.3	41.3	40.8

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.52**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.52**

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Med Load - Med Gas
with No DSM

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	50,149	50,169	50,756	51,704	53,041	54,110	55,361	56,725	59,284	63,396	71,448	71,444
	MWa	5,725	5,727	5,794	5,902	6,055	6,177	6,320	6,475	6,768	7,237	8,156	8,156
	Total Annual Emissions (1000 Tons)												
0.12%	CO2	52,033	52,161	52,440	53,009	53,875	54,375	54,859	55,297	56,531	58,644	60,650	53,273
0.21%	NOx	121.2	121.7	122.1	122.6	123.6	123.8	126.4	125.8	126.2	126.5	126.7	126.0
0.27%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.4	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.72%	CO2	2,075	2,079	2,066	2,050	2,031	2,010	1,982	1,950	1,907	1,850	1,698	1,491
-1.64%	NOx	4.83	4.85	4.81	4.74	4.66	4.58	4.57	4.44	4.26	3.99	3.55	3.53
-1.58%	TSP	0.43	0.43	0.43	0.43	0.42	0.41	0.40	0.39	0.38	0.36	0.32	0.32
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.21	99.58	98.81	97.89	96.85	95.51	93.95	91.90	89.16	81.81	71.87
	NOx	100	100.38	99.58	98.16	96.46	94.71	94.50	91.78	88.08	82.56	73.41	72.99
	TSP	100	100.25	99.53	98.24	96.55	94.95	93.02	90.83	87.38	82.28	73.36	73.93

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,921	1,118,415
NOx	125.2	2,504
TSP	11.2	224

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Med Load - Med Gas
with 20% Conservation Advantage

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	19.9	20.4	20.7	21.2	21.4	21.3	21.3	41.9	62.4	58.9	73.3	397.0
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								139.9	160.9				300.8
C	OWC Cogen 2									70.2	242.1	481.0	342.7	1136.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	14.3	19.9	20.4	20.7	21.2	21.4	21.3	161.2	273.0	304.5	539.9	416.0	1833.8
	DSM Programs	13.8	18.5	18.9	19.0	19.2	19.0	19.0	19.1	37.4	57.0	54.7	68.8	364.4
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											222.1	172.7	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								105.2					105.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	13.8	18.5	18.9	19.0	19.2	19.0	19.0	124.3	37.4	57.0	276.8	241.5	864.4
	DSM Programs	5.2	6.4	6.4	6.5	6.6	6.5	6.6	6.5	12.9	19.6	18.8	23.5	125.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	5.2	6.4	6.4	6.5	6.6	6.5	6.6	6.5	12.9	19.6	18.8	23.5	125.5
	DSM Programs	33.3	44.8	45.7	46.2	47.0	46.9	46.9	46.9	92.2	139.0	132.4	165.6	886.9
T	Renewable													0.0
O	Cogeneration								139.9	231.1	242.1	703.1	515.4	1831.6
T	Combined Cycle CT								105.2					105.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	33.3	44.8	45.7	46.2	47.0	46.9	46.9	292.0	323.3	381.1	835.5	681.0	2823.7

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(78)	(124)	(170)	(217)	(264)	(311)	(358)	(450)	(589)	(721)	(887)
T	**Total Requirements**	9,021	9,138	9,233	9,328	9,533	9,526	9,691	9,850	9,842	9,961	10,415	10,822
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,207	10,122	10,013	9,868	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources								245	476	718	1,421	1,937
&	Summer Purch $6/Year							47					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,855	11,031	11,022	11,156	11,664	12,121
	Reserves	1,229	1,603	1,571	1,480	1,284	1,282	1,164	1,181	1,180	1,194	1,249	1,299
	Reserve Margin (RM) (%)	13.6	17.5	17.0	15.9	13.5	13.5	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with 20% Conservation Advantage

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	25.2	26.4	27.0	27.9	28.2	28.2	28.4	55.7	82.3	75.7	92.7	516.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								148.8	171.2				320.0
C	OWC Cogen 2									74.7	257.5	511.7	364.6	1208.5
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.4**	**25.2**	**26.4**	**27.0**	**27.9**	**28.2**	**28.2**	**177.2**	**301.6**	**339.8**	**587.4**	**457.3**	**2044.6**
	DSM Programs	16.1	20.3	21.2	21.3	21.5	21.3	21.1	21.2	41.6	62.9	59.3	74.0	401.8
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											236.3	183.7	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								117.2					117.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**16.1**	**20.3**	**21.2**	**21.3**	**21.5**	**21.3**	**21.1**	**138.4**	**41.6**	**62.9**	**295.6**	**257.7**	**939.0**
	DSM Programs	4.9	5.6	5.7	5.7	5.9	6.1	6.0	6.1	12.2	18.8	18.2	22.7	117.9
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.9**	**5.6**	**5.7**	**5.7**	**5.9**	**6.1**	**6.0**	**6.1**	**12.2**	**18.8**	**18.2**	**22.7**	**117.9**
	DSM Programs	39.4	51.1	53.3	54.0	55.3	55.6	55.3	55.7	109.5	164.0	153.2	189.4	1035.8
T	Renewable													0.0
O	Cogeneration								148.8	245.9	257.5	748.0	548.3	1948.5
T	Combined Cycle CT								117.2					117.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**39.4**	**51.1**	**53.3**	**54.0**	**55.3**	**55.6**	**55.3**	**321.7**	**355.4**	**421.5**	**901.2**	**737.7**	**3101.5**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(91)	(144)	(198)	(253)	(309)	(364)	(420)	(529)	(693)	(846)	(1,036)
T	**Total Requirements**	**8,993**	**9,004**	**9,055**	**9,059**	**9,145**	**9,283**	**9,427**	**9,587**	**9,570**	**9,776**	**10,110**	**10,486**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,892	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								266	512	769	1,517	2,066
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,020**	**11,282**	**10,992**	**11,086**	**11,679**	**12,204**
	Reserves	1,355	1,847	1,965	1,982	1,881	1,735	1,593	1,695	1,422	1,310	1,569	1,718
	Reserve Margin (RM) (%)	15.1	20.5	21.7	21.9	20.6	18.7	16.9	17.7	14.9	13.4	15.5	16.4

Med Load - Med Gas with 20% Conservation Advantage

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	21.4	33.9	46.5	59.5	72.7	85.8	99.0	124.9	163.4	199.8	244.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								138.5	297.9	297.9	297.9	297.9
C	OWC Cogen 2									69.5	309.1	768.8	1,017.2
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.3**	**21.4**	**33.9**	**46.5**	**59.5**	**72.7**	**85.8**	**237.5**	**492.2**	**770.4**	**1,266.4**	**1,559.8**
	DSM Programs	10.1	22.8	35.7	48.6	61.7	74.7	87.7	100.7	126.3	165.4	203.0	250.1
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											212.5	363.4
T	Utah Combined Cycle												
A	Utah Gadsby Repower								87.1	88.0	92.0	73.1	68.0
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**10.1**	**22.8**	**35.7**	**48.6**	**61.7**	**74.7**	**87.7**	**187.8**	**214.4**	**257.4**	**488.5**	**681.5**
	DSM Programs	4.1	8.8	13.6	18.3	23.2	28.1	33.0	37.9	47.7	62.6	77.2	95.3
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**4.1**	**8.8**	**13.6**	**18.3**	**23.2**	**28.1**	**33.0**	**37.9**	**47.7**	**62.6**	**77.2**	**95.3**
	DSM Programs	23.5	53.0	83.1	113.5	144.4	175.5	206.5	237.6	298.9	391.5	479.9	590.2
T	Renewable												
O	Cogeneration								138.5	367.4	607.0	1,279.1	1,678.4
T	Combined Cycle CT								87.1	88.0	92.0	73.1	68.0
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**23.5**	**53.0**	**83.1**	**113.5**	**144.4**	**175.5**	**206.5**	**463.2**	**754.3**	**1,090.4**	**1,832.0**	**2,336.6**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.1	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	493.0	758.1	801.5	774.3	725.2	707.7	625.6	753.6	884.2	880.1	1,074.9	1,240.5
E	**DSM Programs**	(23.5)	(52.9)	(83.1)	(113.5)	(144.4)	(175.5)	(206.5)	(237.6)	(298.9)	(391.5)	(479.9)	(590.2)
M	**Total Requirements**	7,800.1	8,054.8	8,084.7	8,096.8	8,150.2	8,199.1	8,228.7	8,446.1	8,618.5	8,818.6	9,287.8	9,615.8
	Existing Generation	7,161.0	7,514.8	7,571.1	7,600.4	7,652.1	7,687.1	7,715.0	7,740.8	7,745.9	7,710.2	7,556.4	7,510.9
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	82.1	36.3	40.7	31.8	44.1	66.6	71.5	40.5	17.7	27.6	0.6	
R	**New Resources**								225.6	455.4	699.0	1,352.2	1,746.4
	Total Resources	7,800.1	8,054.8	8,084.7	8,096.8	8,150.2	8,199.1	8,228.8	8,446.1	8,618.5	8,818.6	9,287.8	9,615.8

Med Load - Med Gas
with 20% Conservation Advantage

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	53	83	113	144	175	206	237	299	392	480	596
			After Conservation												
			System Load (MWa)	5,701	5,674	5,712	5,792	5,914	6,005	6,117	6,242	6,473	6,850	7,181	7,546
	0.49		Energy Sales (MWa)	5,152	5,154	5,209	5,295	5,393	5,493	5,596	5,701	5,860	6,087	6,397	6,530
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,085	8,305	8,512	8,724	8,915	9,264	9,682	10,028	10,639	11,595	13,238	15,104
			Net Conservation Assets ($M)	52	124	197	243	287	329	368	405	472	547	585	653
			Utility Cost												
42,564	3.28	Nominal	**Operating Revenues ($M)**	2,211	2,195	2,234	2,326	2,423	2,545	2,633	2,687	2,963	3,398	3,900	4,519
	-0.02	Real		2,211	2,125	2,093	2,110	2,127	2,164	2,167	2,140	2,212	2,302	2,396	2,439
	2.77	Nominal	Cost in mills/kWh	49.0	48.6	49.0	50.1	51.3	52.9	53.7	53.8	57.7	63.7	69.6	79.0
	-0.51	Real		49.0	47.1	45.9	45.5	45.0	45.0	44.2	42.9	43.1	43.2	42.8	42.6
		Nominal	Average Customer Bill ($)	1,667	1,639	1,646	1,686	1,724	1,782	1,814	1,820	1,944	2,125	2,339	2,640
		Real		1,667	1,586	1,542	1,529	1,514	1,515	1,493	1,450	1,451	1,440	1,437	1,425
			Total Resource Cost												
			DSR Customer Cost ($M)	0.6	2.1	3.6	7.7	11.4	14.7	18.0	20.9	24.9	26.3	23.8	11.3
			Levelized (20-year at 8.6%)	0.1	0.3	0.7	1.5	2.7	4.3	6.2	8.4	13.5	21.9	29.9	37.0
			Energy Svc Charge ($M)	4.6	11.7	19.2	23.6	28.2	32.9	37.8	42.8	53.3	70.1	83.7	86.9
43,259	3.28	Nominal	**Total Resource Cost ($M)**	2,216	2,207	2,254	2,351	2,453	2,582	2,677	2,738	3,030	3,490	4,013	4,643
	-0.02	Real		2,216	2,136	2,112	2,133	2,155	2,195	2,203	2,181	2,262	2,364	2,466	2,505
	2.60	Nominal	Cost in mills/kWh	48.9	48.4	48.7	49.7	50.7	52.1	52.8	52.8	56.4	61.8	67.0	74.9
	-0.67	Real		48.9	46.9	45.6	45.1	44.5	44.3	43.5	42.1	42.1	41.9	41.2	40.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.00

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.32

Med Load - Med Gas
with 20% Conservation Advantage

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,944	49,705	50,028	50,711	51,776	52,574	53,552	54,643	56,667	59,967	66,111	65,747
	MWa	5,701	5,674	5,711	5,789	5,910	6,002	6,113	6,238	6,469	6,846	7,547	7,505
	Total Annual Emissions (1000 Tons)												
0.17%	CO2	51,934	51,910	52,047	52,487	53,182	53,609	54,109	54,521	55,478	57,283	58,893	53,663
0.23%	NOx	121.1	121.5	121.9	122.3	123.1	123.5	126.6	126.3	126.6	127.0	127.0	126.6
0.25%	TSP	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.27%	CO2	2,080	2,089	2,081	2,070	2,054	2,039	2,021	1,996	1,958	1,910	1,782	1,632
-1.21%	NOx	4.85	4.89	4.87	4.82	4.76	4.70	4.73	4.62	4.47	4.23	3.84	3.85
-1.19%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.42	0.41	0.40	0.38	0.34	0.35
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.43	100.05	99.53	98.78	98.06	97.17	95.95	94.15	91.86	85.67	78.49
	NOx	100	100.79	100.45	99.46	98.05	96.82	97.45	95.32	92.09	87.30	79.21	79.38
	TSP	100	100.61	100.34	99.46	98.03	96.95	95.57	93.83	90.82	86.47	78.64	79.61

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,094	1,101,888
NOx	125.4	2,508
TSP	11.2	224

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Med Load - Med Gas
with 15% Conservation Advantage

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	20.4	20.7	21.1	21.4	21.3	21.4	41.8	62.5	58.9	73.2	392.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal								150.4	150.4				300.8
W	OWC Cogen 1									80.8	242.1	479.1	344.7	1146.7
C	OWC Cogen 2													0.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.3**	**15.7**	**20.4**	**20.7**	**21.1**	**21.4**	**21.3**	**171.8**	**273.0**	**304.6**	**538.0**	**417.9**	**1840.2**
	DSM Programs	13.8	14.1	14.6	19.1	19.1	19.1	19.0	19.0	37.5	57.0	54.7	68.7	355.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1											224.0	170.8	394.8
U	Utah Cogen 2													0.0
T	Utah Combined Cycle								110.4					110.4
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													
	Total	**13.8**	**14.1**	**14.6**	**19.1**	**19.1**	**19.1**	**19.0**	**129.4**	**37.5**	**57.0**	**278.7**	**239.5**	**860.9**
	DSM Programs	5.2	5.3	6.4	6.5	6.5	6.6	6.5	6.6	12.9	19.6	18.8	23.4	124.3
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													
	Total	**5.2**	**5.3**	**6.4**	**6.5**	**6.5**	**6.6**	**6.5**	**6.6**	**12.9**	**19.6**	**18.8**	**23.4**	**124.3**
	DSM Programs	33.3	35.1	41.4	46.3	46.7	47.1	46.8	47.0	92.2	139.1	132.4	165.3	872.7
T	Renewable													0.0
O	Cogeneration								150.4	231.2	242.1	703.1	515.5	1842.3
T	Combined Cycle CT								110.4					110.4
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**33.3**	**35.1**	**41.4**	**46.3**	**46.7**	**47.1**	**46.8**	**307.8**	**323.4**	**381.2**	**835.5**	**680.8**	**2825.4**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(68)	(110)	(156)	(203)	(250)	(297)	(344)	(436)	(575)	(707)	(873)
T	**Total Requirements**	9,021	9,148	9,247	9,342	9,547	9,540	9,705	9,864	9,856	9,975	10,429	10,836
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,207	10,122	10,013	9,868	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources								261	492	734	1,437	1,953
&	Summer Purch $6/Year							62					
R	Total Resources	10,250	10,741	10,804	10,808	10,817	10,808	10,870	11,047	11,038	11,171	11,679	12,137
	Reserves	1,229	1,593	1,557	1,466	1,270	1,268	1,165	1,183	1,182	1,196	1,251	1,301
	Reserve Margin (RM) (%)	13.6	17.4	16.8	15.7	13.3	13.3	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with 15% Conservation Advantage

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	26.4	27.0	27.8	28.3	28.1	28.5	55.6	82.3	75.7	92.7	512.6
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2									85.9	257.6	509.7	366.7	1219.9
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	18.4	21.8	26.4	27.0	27.8	28.3	28.1	188.5	301.5	339.9	585.4	459.4	2052.5
	DSM Programs	16.0	16.9	17.7	21.3	21.4	21.3	21.1	21.1	41.5	62.8	59.3	73.9	394.3
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											238.3	181.7	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								123.0					123.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	16.0	16.9	17.7	21.3	21.4	21.3	21.1	144.1	41.5	62.8	297.6	255.6	937.3
	DSM Programs	4.7	4.9	5.4	5.5	5.6	5.8	5.8	5.8	11.7	18.1	17.5	22.5	113.3
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.7	4.9	5.4	5.5	5.6	5.8	5.8	5.8	11.7	18.1	17.5	22.5	113.3
	DSM Programs	39.1	43.6	49.5	53.8	54.8	55.4	55.0	55.4	108.8	163.2	152.5	189.1	1020.2
T	Renewable													0.0
O	Cogeneration								160.0	245.9	257.6	748.0	548.4	1959.9
T	Combined Cycle CT								123.0					123.0
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	39.1	43.6	49.5	53.8	54.8	55.4	55.0	338.4	354.7	420.8	900.5	737.5	3103.1

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(83)	(132)	(186)	(241)	(296)	(351)	(407)	(515)	(679)	(831)	(1,020)
T	**Total Requirements**	8,993	9,011	9,067	9,071	9,157	9,296	9,440	9,600	9,584	9,790	10,125	10,502
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,046	9,892	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								283	529	787	1,535	2,083
&	Summer Purch $6/Year												
R	**Total Resources**	10,348	10,850	11,020	11,041	11,026	11,018	11,020	11,299	11,009	11,102	11,696	12,221
	Reserves	1,355	1,839	1,953	1,970	1,869	1,722	1,580	1,699	1,426	1,311	1,571	1,719
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.7	20.4	18.5	16.7	17.7	14.9	13.4	15.5	16.4

Med Load - Med Gas
with 15% Conservation Advantage

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	31.8	44.5	57.5	70.6	83.8	97.0	122.8	161.4	197.7	242.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2									80.0	319.6	776.8	1,021.6
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.3**	**19.3**	**31.8**	**44.5**	**57.5**	**70.6**	**83.8**	**245.9**	**500.6**	**778.8**	**1,272.4**	**1,562.2**
	DSM Programs	10.1	20.5	31.2	44.2	57.2	70.2	83.2	96.2	121.8	160.8	198.3	245.5
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											214.6	365.1
T	Utah Combined Cycle												
A	Utah Gadsby Repower								91.3	92.3	96.5	77.1	70.5
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**10.1**	**20.5**	**31.2**	**44.2**	**57.2**	**70.2**	**83.2**	**187.5**	**214.1**	**257.3**	**490.0**	**681.0**
	DSM Programs	4.1	8.2	12.9	17.5	22.3	27.1	31.9	36.7	46.3	61.0	75.3	93.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**4.1**	**8.2**	**12.9**	**17.5**	**22.3**	**27.1**	**31.9**	**36.7**	**46.3**	**61.0**	**75.3**	**93.4**
	DSM Programs	23.4	48.0	75.9	106.2	137.0	167.9	198.8	229.8	290.9	383.1	471.3	581.6
T	Renewable												
O	Cogeneration								148.9	377.8	617.5	1,289.3	1,684.6
T	Combined Cycle CT								91.3	92.3	96.5	77.1	70.5
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**23.4**	**48.0**	**75.9**	**106.2**	**137.0**	**167.9**	**198.8**	**470.1**	**761.1**	**1,097.1**	**1,837.6**	**2,336.6**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	309.7	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	511.4	759.4	803.7	765.7	720.3	704.5	618.8	751.1	888.5	891.7	1,081.4	1,241.6
E	**DSM Programs**	(23.4)	(48.0)	(75.9)	(106.2)	(137.0)	(167.9)	(198.8)	(229.8)	(290.9)	(383.1)	(471.3)	(581.6)
M	**Total Requirements**	7,818.6	8,060.6	8,094.1	8,095.5	8,152.8	8,203.5	8,229.6	8,451.4	8,630.8	8,838.4	9,302.8	9,625.6
	Existing Generation	7,161.0	7,515.0	7,574.3	7,601.1	7,653.9	7,690.4	7,715.1	7,740.5	7,746.1	7,711.3	7,557.3	7,512.1
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	100.6	41.9	46.9	29.7	44.8	67.6	72.3	31.5	15.0	31.4	0.6	
R	**New Resources**								240.2	470.2	714.0	1,366.3	1,755.0
	Total Resources	7,818.6	8,060.6	8,094.1	8,095.5	8,152.8	8,203.5	8,229.7	8,451.4	8,630.8	8,838.4	9,302.8	9,625.6

Med Load - Med Gas
with 15% Conservation Advantage

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	48	75	106	136	167	198	229	292	385	472	589
			After Conservation												
			System Load (MWa)	5,701	5,679	5,719	5,800	5,922	6,013	6,125	6,249	6,481	6,857	7,188	7,553
	0.49		Energy Sales (MWa)	5,152	5,159	5,216	5,302	5,399	5,500	5,603	5,708	5,866	6,093	6,404	6,536
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,285	8,482	8,695	8,888	9,248	9,681	10,025	10,636	11,598	13,249	15,115
			Net Conservation Assets ($M)	52	104	167	214	258	301	343	382	453	536	583	653
			Utility Cost												
42,571	3.28	Nominal	**Operating Revenues ($M)**	2,211	2,197	2,235	2,325	2,422	2,545	2,635	2,685	2,965	3,399	3,901	4,521
(1) 42560	-0.02	Real		2,211	2,127	2,094	2,110	2,127	2,163	2,168	2,139	2,214	2,302	2,397	2,440
	2.77	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.1	51.2	52.8	53.7	53.7	57.7	63.7	69.5	79.0
	-0.51	Real		49.0	47.1	45.8	45.4	45.0	44.9	44.2	42.8	43.1	43.1	42.7	42.6
		Nominal	Average Customer Bill ($)	1,667	1,640	1,646	1,685	1,724	1,782	1,815	1,819	1,945	2,126	2,340	2,641
		Real		1,667	1,588	1,543	1,529	1,514	1,515	1,494	1,449	1,452	1,440	1,438	1,425
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.8	3.1	7.1	10.8	13.8	17.1	19.8	23.8	25.0	22.4	9.7
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.4	2.5	4.0	5.8	7.9	12.8	20.8	28.3	34.8
			Energy Svc Charge ($M)	4.6	9.4	15.7	20.1	24.7	29.4	34.3	39.3	49.8	66.6	80.2	86.9
43,225	3.28	Nominal	**Total Resource Cost ($M)**	2,216	2,207	2,251	2,347	2,449	2,578	2,675	2,732	3,028	3,486	4,009	4,643
42 990	-0.02	Real		2,216	2,136	2,109	2,129	2,151	2,192	2,201	2,176	2,260	2,361	2,464	2,505
	2.60	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.6	50.6	52.1	52.8	52.7	56.4	61.8	67.0	74.9
	-0.68	Real		48.9	46.9	45.6	45.0	44.5	44.3	43.4	42.0	42.1	41.8	41.1	40.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.96

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.29

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Med Load - Med Gas
with 15% Conservation Advantage

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,944	49,745	50,091	50,775	51,841	52,640	53,620	54,711	56,737	60,039	66,187	65,751
	MWa	5,701	5,679	5,718	5,796	5,918	6,009	6,121	6,246	6,477	6,854	7,556	7,506
	Total Annual Emissions (1000 Tons)												
0.17%	CO2	51,935	51,933	52,080	52,520	53,219	53,645	54,139	54,548	55,508	57,309	58,921	53,658
0.23%	NOx	121.1	121.5	121.9	122.4	123.2	123.5	126.6	126.3	126.6	127.0	127.0	126.6
0.25%	TSP	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.27%	CO2	2,080	2,088	2,079	2,069	2,053	2,038	2,019	1,994	1,957	1,909	1,780	1,632
-1.21%	NOx	4.85	4.89	4.87	4.82	4.75	4.69	4.72	4.62	4.46	4.23	3.84	3.85
-1.19%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.42	0.41	0.39	0.38	0.34	0.35
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.40	99.99	99.47	98.72	98.00	97.10	95.88	94.09	91.79	85.61	78.48
	NOx	100	100.72	100.34	99.36	97.96	96.72	97.33	95.19	91.97	87.18	79.11	79.38
	TSP	100	100.55	100.24	99.36	97.94	96.86	95.45	93.72	90.72	86.36	78.55	79.63

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,118	1,102,360
NOx	125.4	2,508
TSP	11.2	224

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Med Load - Med Gas
with 15% Conservation Disadvantage

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	9.9	14.1	14.6	14.8	15.7	15.8	15.8	15.9	31.1	46.2	42.6	52.6	289.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2								26.4	23.6	291.8	541.1	357.9	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	9.9	14.1	14.6	14.8	15.7	15.8	15.8	192.7	205.1	338.0	583.7	410.5	1830.7
	DSM Programs	8.0	9.3	10.5	10.7	12.4	12.3	12.3	12.3	24.2	36.7	34.5	43.0	226.2
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1												36.7	36.7
U	Utah Cogen 2											211.3	183.5	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							39.4	168.1	89.7	(0.0)	(0.0)	0.1	297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	8.0	9.3	10.5	10.7	12.4	12.3	51.7	180.4	113.9	36.7	245.8	263.3	955.0
	DSM Programs	2.4	3.3	3.6	3.9	3.9	4.0	3.9	4.0	7.9	11.9	11.1	13.9	73.8
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	2.4	3.3	3.6	3.9	3.9	4.0	3.9	4.0	7.9	11.9	11.1	13.9	73.8
	DSM Programs	20.3	26.7	28.7	29.4	32.0	32.1	32.0	32.2	63.2	94.8	88.2	109.5	589.1
T	Renewable													0.0
O	Cogeneration								176.8	174.0	291.8	752.4	578.1	1973.1
T	Combined Cycle CT							39.4	168.1	89.7	(0.0)	(0.0)	0.1	297.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	20.3	26.7	28.7	29.4	32.0	32.1	71.4	377.1	326.9	386.6	840.6	687.7	2859.5

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(20)	(47)	(76)	(105)	(137)	(169)	(201)	(233)	(297)	(391)	(480)	(589)
T	**Total Requirements**	9,034	9,169	9,281	9,393	9,613	9,621	9,801	9,975	9,995	10,159	10,656	11,120
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,207	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							39	384	648	940	1,692	2,270
&	Summer Purch $6/Year							130					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,977	11,171	11,195	11,378	11,935	12,454
	Reserves	1,216	1,572	1,523	1,415	1,204	1,187	1,176	1,197	1,200	1,219	1,279	1,335
	Reserve Margin (RM) (%)	13.5	17.1	16.4	15.1	12.5	12.3	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with 15% Conservation Disadvantage

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.6	19.4	20.4	21.0	22.5	23.0	23.0	23.2	45.5	66.9	60.8	73.5	413.8
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2								28.1	25.1	310.4	575.7	380.7	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.6**	**19.4**	**20.4**	**21.0**	**22.5**	**23.0**	**23.0**	**211.3**	**230.6**	**377.3**	**636.5**	**454.2**	**2053.8**
	DSM Programs	10.1	11.6	13.7	13.9	15.7	15.6	15.4	15.5	30.2	45.6	41.9	51.9	281.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1												39.0	39.0
U	Utah Cogen 2											224.8	195.2	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							43.9	187.3	99.9	(0.0)	(0.0)	0.1	331.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**10.1**	**11.6**	**13.7**	**13.9**	**15.7**	**15.6**	**59.3**	**202.8**	**130.1**	**45.6**	**266.7**	**286.2**	**1071.3**
	DSM Programs	2.1	2.8	3.2	3.4	3.5	3.6	3.6	3.6	7.1	10.7	9.8	12.1	65.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**2.1**	**2.8**	**3.2**	**3.4**	**3.5**	**3.6**	**3.6**	**3.6**	**7.1**	**10.7**	**9.8**	**12.1**	**65.5**
	DSM Programs	26.8	33.8	37.3	38.3	41.7	42.2	42.0	42.3	82.8	123.2	112.5	137.5	760.4
T	Renewable													0.0
O	Cogeneration								188.1	185.1	310.4	800.5	614.9	2099.0
T	Combined Cycle CT							43.9	187.3	99.9	(0.0)	(0.0)	0.1	331.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**26.8**	**33.8**	**37.3**	**38.3**	**41.7**	**42.2**	**85.9**	**417.7**	**367.8**	**433.6**	**913.0**	**752.5**	**3190.6**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(27)	(61)	(98)	(136)	(178)	(220)	(262)	(304)	(387)	(510)	(623)	(760)
T	**Total Requirements**	**9,005**	**9,033**	**9,101**	**9,121**	**9,220**	**9,372**	**9,529**	**9,703**	**9,712**	**9,959**	**10,333**	**10,762**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							44	419	704	1,015	1,815	2,430
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,850	11,020	11,041	11,026	11,018	11,064	11,435	11,184	11,331	11,977	12,568
	Reserves	1,343	1,817	1,919	1,920	1,806	1,646	1,535	1,733	1,472	1,372	1,644	1,807
	Reserve Margin (RM) (%)	14.9	20.1	21.1	21.1	19.6	17.6	16.1	17.9	15.2	13.8	15.9	16.8

Med Load - Med Gas with 15% Conservation Disadvantage

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	6.2	14.9	23.8	33.0	42.7	52.5	62.3	72.1	91.4	120.1	146.5	179.1
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2								26.2	49.5	338.3	847.1	1,114.2
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**6.2**	**14.9**	**23.8**	**33.0**	**42.7**	**52.5**	**62.3**	**247.3**	**438.8**	**756.2**	**1,291.5**	**1,591.2**
	DSM Programs	5.6	11.8	18.8	25.9	34.7	43.5	52.2	61.0	78.2	104.4	129.0	159.9
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												36.3
U	Utah Cogen 2											207.0	369.3
T	Utah Combined Cycle												
A	Utah Gadsby Repower							32.9	162.9	236.6	251.8	208.2	147.4
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**5.6**	**11.8**	**18.8**	**25.9**	**34.7**	**43.5**	**85.2**	**223.8**	**314.8**	**356.2**	**544.2**	**712.9**
	DSM Programs	1.9	4.2	6.8	9.4	12.2	15.0	17.7	20.5	26.0	34.4	42.3	52.0
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**1.9**	**4.2**	**6.8**	**9.4**	**12.2**	**15.0**	**17.7**	**20.5**	**26.0**	**34.4**	**42.3**	**52.0**
	DSM Programs	13.7	30.9	49.4	68.3	89.6	110.9	132.2	153.6	195.7	258.8	317.8	391.0
T	Renewable												
O	Cogeneration								175.1	347.4	636.2	1,352.0	1,817.6
T	Combined Cycle CT							32.9	162.9	236.6	251.8	208.2	147.4
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**13.7**	**30.9**	**49.4**	**68.3**	**89.6**	**110.9**	**165.2**	**491.6**	**779.7**	**1,146.7**	**1,878.0**	**2,356.1**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.3	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	492.0	743.8	785.2	752.1	689.7	652.1	591.1	793.3	937.4	960.2	1,154.2	1,244.8
E	**DSM Programs**	(13.7)	(30.9)	(49.4)	(68.3)	(89.6)	(110.9)	(132.2)	(153.6)	(195.7)	(258.8)	(317.8)	(391.0)
M	**Total Requirements**	7,809.0	8,062.7	8,101.6	8,119.8	8,169.6	8,208.1	8,268.5	8,569.8	8,774.9	9,031.3	9,529.1	9,819.4
	Existing Generation	7,161.5	7,518.0	7,584.2	7,610.6	7,665.9	7,702.7	7,730.0	7,755.0	7,787.1	7,759.4	7,590.3	7,495.8
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	90.4	41.0	44.5	44.5	49.6	59.9	63.3	37.7	4.2	2.2		
R	**New Resources**							32.9	338.0	584.0	887.9	1,560.2	1,965.1
	Total Resources	7,809.0	8,062.7	8,101.6	8,119.8	8,169.6	8,208.1	8,268.5	8,569.8	8,774.9	9,031.3	9,529.1	9,819.3

Case # 14

Med Load - Med Gas
with 15% Conservation Disadvantage

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	14	31	49	68	89	111	132	153	196	259	317	393
			After Conservation												
			System Load (MWa)	5,710	5,696	5,745	5,837	5,969	6,070	6,191	6,325	6,577	6,983	7,344	7,749
	0.55		Energy Sales (MWa)	5,161	5,174	5,240	5,336	5,443	5,552	5,664	5,778	5,954	6,209	6,546	6,716
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,066	8,252	8,427	8,625	8,831	9,248	9,725	10,078	10,685	11,660	13,328	15,274
			Net Conservation Assets ($M)	34	72	112	142	172	201	228	253	299	350	375	413
			Utility Cost												
42,578	3.28	Nominal	**Operating Revenues ($M)**	2,213	2,199	2,238	2,329	2,426	2,550	2,635	2,670	2,933	3,365	3,886	4,540
	-0.02	Real		2,213	2,128	2,097	2,113	2,131	2,168	2,169	2,127	2,190	2,279	2,388	2,450
	2.71	Nominal	Cost in mills/kWh	49.0	48.5	48.8	49.8	50.9	52.4	53.1	52.8	56.2	61.9	67.8	77.2
	-0.57	Real		49.0	47.0	45.7	45.2	44.7	44.6	43.7	42.0	42.0	41.9	41.6	41.7
		Nominal	Average Customer Bill ($)	1,669	1,642	1,649	1,688	1,727	1,786	1,815	1,809	1,924	2,104	2,331	2,652
		Real		1,669	1,589	1,545	1,531	1,517	1,518	1,494	1,441	1,436	1,425	1,432	1,431
			Total Resource Cost												
			DSR Customer Cost ($M)	0.5	1.0	1.5	3.1	4.7	5.9	6.6	6.8	5.0	-4.0	-19.4	-52.5
			Levelized (20-year at 8.6%)	0.1	0.2	0.3	0.7	1.2	1.8	2.5	3.2	4.4	4.7	4.7	4.7
			Energy Svc Charge ($M)	2.8	6.1	9.8	12.2	14.9	17.8	20.7	23.7	29.9	39.8	47.6	50.9
42,905	3.28	Nominal	**Total Resource Cost ($M)**	2,216	2,205	2,248	2,342	2,442	2,570	2,658	2,697	2,967	3,409	3,938	4,596
	-0.02	Real		2,216	2,135	2,107	2,124	2,145	2,185	2,188	2,149	2,215	2,309	2,420	2,480
	2.60	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.5	50.5	51.9	52.5	52.0	55.2	60.4	65.8	74.2
	-0.68	Real		48.9	46.8	45.5	44.9	44.3	44.1	43.2	41.5	41.2	40.9	40.4	40.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.17

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 40.98

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Med Load - Med Gas
with 15% Conservation Disadvantage

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	50,030	49,899	50,319	51,106	52,256	53,139	54,203	55,379	57,570	61,129	67,856	67,555
	MWa	5,711	5,696	5,744	5,834	5,965	6,066	6,188	6,322	6,572	6,978	7,746	7,712
	Total Annual Emissions (1000 Tons)												
0.12%	CO2	51,976	52,014	52,207	52,698	53,459	53,917	54,387	54,762	55,761	57,665	59,443	53,223
0.20%	NOx	121.1	121.6	122.0	122.5	123.4	123.7	126.5	126.0	126.1	126.4	126.7	125.9
0.25%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.1	11.2	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.45%	CO2	2,078	2,085	2,075	2,062	2,046	2,029	2,007	1,978	1,937	1,887	1,752	1,576
-1.37%	NOx	4.84	4.87	4.85	4.79	4.72	4.65	4.67	4.55	4.38	4.14	3.73	3.73
-1.32%	TSP	0.43	0.44	0.43	0.43	0.42	0.42	0.41	0.40	0.39	0.37	0.33	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.34	99.87	99.25	98.47	97.67	96.58	95.18	93.23	90.80	84.32	75.84
	NOx	100	100.62	100.11	98.96	97.50	96.11	96.41	93.95	90.42	85.41	77.09	76.98
	TSP	100	100.46	100.03	98.99	97.53	96.30	94.67	92.74	89.62	85.03	76.94	77.72

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,315	1,106,306
NOx	125.1	2,502
TSP	11.2	224

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PacifiCorp RAMPP-4

Case # 21

Med Low Load - Med Gas

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	2.5	2.6	2.6	2.8	2.9	3.1	3.1	9.7	24.6	38.0	36.2	45.5	173.6
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1												28.8	28.8
C	OWC Cogen 2													0.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	2.5	2.6	2.6	2.8	2.9	3.1	3.1	9.7	24.6	38.0	36.2	74.3	202.4
	DSM Programs	2.3	2.3	2.2	2.4	2.5	2.5	2.5	2.6	20.4	32.3	30.2	38.1	140.3
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2													0.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	2.3	2.3	2.2	2.4	2.5	2.5	2.5	2.6	20.4	32.3	30.2	38.1	140.3
	DSM Programs	1.4	1.5	1.4	1.5	1.5	1.5	1.5	1.6	6.3	10.2	10.3	12.8	51.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	1.4	1.5	1.4	1.5	1.5	1.5	1.5	1.6	6.3	10.2	10.3	12.8	51.5
	DSM Programs	6.2	6.4	6.2	6.7	6.9	7.1	7.1	13.9	51.3	80.5	76.7	96.4	365.4
T	Renewable													0.0
O	Cogeneration												28.8	28.8
T	Combined Cycle CT													0.0
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	6.2	6.4	6.2	6.7	6.9	7.1	7.1	13.9	51.3	80.5	76.7	125.2	394.2

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	6,892	6,827	6,885	6,958	7,090	7,144	7,272	7,385	7,597	7,943	8,227	8,557
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(6)	(13)	(19)	(26)	(32)	(40)	(47)	(61)	(112)	(192)	(269)	(365)
T	Total Requirements	8,671	8,714	8,766	8,808	8,948	8,900	9,020	9,120	8,970	8,928	9,060	9,119
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources												29
&	Summer Purch $6/Year												
R	Total Resources	10,250	10,741	10,804	10,808	10,817	10,808	10,808	10,787	10,547	10,438	10,243	10,213
	Reserves	1,579	2,027	2,038	2,001	1,869	1,909	1,788	1,668	1,577	1,510	1,183	1,094
	Reserve Margin (RM) (%)	18.2	23.2	23.2	22.7	20.9	21.4	19.8	18.3	17.6	16.9	13.1	12.0

Med Low Load - Med Gas

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	2.6	2.7	2.8	2.9	3.1	3.4	3.4	12.5	34.4	54.7	53.0	65.2	240.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1												30.6	30.6
C	OWC Cogen 2													0.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**2.6**	**2.7**	**2.8**	**2.9**	**3.1**	**3.4**	**3.4**	**12.5**	**34.4**	**54.7**	**53.0**	**95.8**	**271.3**
	DSM Programs	2.4	2.5	2.4	2.5	2.7	2.8	2.7	2.9	24.6	39.8	36.8	45.6	167.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2													0.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**2.4**	**2.5**	**2.4**	**2.5**	**2.7**	**2.8**	**2.7**	**2.9**	**24.6**	**39.8**	**36.8**	**45.6**	**167.7**
	DSM Programs	1.5	1.4	1.5	1.6	1.5	1.6	1.6	1.6	5.7	9.4	9.5	12.2	49.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.5**	**1.4**	**1.5**	**1.6**	**1.5**	**1.6**	**1.6**	**1.6**	**5.7**	**9.4**	**9.5**	**12.2**	**49.1**
	DSM Programs	6.5	6.6	6.7	7.0	7.3	7.8	7.7	17.0	64.7	103.9	99.3	123.0	457.5
T	Renewable													0.0
O	Cogeneration												30.6	30.6
T	Combined Cycle CT													0.0
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**6.5**	**6.6**	**6.7**	**7.0**	**7.3**	**7.8**	**7.7**	**17.0**	**64.7**	**103.9**	**99.3**	**153.6**	**488.1**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,183	7,142	7,167	7,236	7,333	7,436	7,547	7,673	7,895	8,234	8,558	8,929
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(7)	(13)	(20)	(27)	(34)	(42)	(50)	(67)	(131)	(235)	(335)	(458)
T	**Total Requirements**	**8,640**	**8,592**	**8,610**	**8,572**	**8,612**	**8,707**	**8,810**	**8,919**	**8,759**	**8,736**	**8,836**	**8,909**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources												31
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,020**	**11,016**	**10,480**	**10,316**	**10,162**	**10,169**
	Reserves	1,709	2,258	2,410	2,469	2,414	2,311	2,210	2,097	1,721	1,580	1,327	1,260
	Reserve Margin (RM) (%)	19.8	26.3	28.0	28.8	28.0	26.5	25.1	23.5	19.7	18.1	15.0	14.1

Med Low Load - Med Gas

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	2.0	4.0	6.1	8.2	10.5	12.8	15.2	21.0	37.0	61.6	85.3	114.9
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1												28.5
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	2.0	4.0	6.1	8.2	10.5	12.8	15.2	21.0	37.0	61.6	85.3	143.5
	DSM Programs	2.1	4.2	6.3	8.4	10.6	12.9	15.1	17.5	31.7	54.2	75.3	102.0
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2												
T	Utah Combined Cycle												
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	2.1	4.2	6.3	8.4	10.6	12.9	15.1	17.5	31.7	54.2	75.3	102.0
	DSM Programs	1.4	2.7	4.1	5.5	6.9	8.4	9.8	11.2	16.3	24.5	32.8	43.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	1.4	2.7	4.1	5.5	6.9	8.4	9.8	11.2	16.3	24.5	32.8	43.4
	DSM Programs	5.4	10.9	16.4	22.1	28.0	34.1	40.1	49.7	84.9	140.3	193.4	260.3
T	Renewable												
O	Cogeneration												28.5
T	Combined Cycle CT												
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	5.4	10.9	16.4	22.1	28.0	34.1	40.1	49.7	84.9	140.3	193.4	288.8
S	Native Load	5,141.0	5,068.6	5,076.9	5,124.8	5,207.6	5,270.1	5,344.6	5,434.9	5,595.7	5,854.1	6,066.0	6,285.9
Y	Pump Storage/Peak Return	310.6	309.4	308.3	306.7	306.6	306.8	306.5	306.5	305.0	305.0	305.0	305.0
S	Firm Sales	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	Non-Firm Sales	700.6	953.4	983.3	978.7	959.3	964.5	935.6	911.4	978.3	926.7	781.1	847.2
E	DSM Programs	(5.4)	(10.9)	(16.4)	(22.1)	(28.0)	(34.0)	(40.1)	(49.7)	(84.9)	(140.2)	(193.4)	(260.3)
M	Total Requirements	7,752.6	7,943.2	7,924.4	7,921.6	7,960.1	7,997.1	8,036.4	8,057.9	8,059.6	8,038.5	7,995.9	8,006.1
	Existing Generation	7,134.6	7,437.9	7,451.4	7,456.9	7,503.6	7,548.2	7,588.0	7,617.0	7,651.9	7,632.0	7,561.9	7,555.7
L	Firm Purchases	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	Non-Firm Purchases	61.0	1.5			2.4	3.4	6.2	1.8	8.1	24.8	55.4	63.4
R	New Resources												28.5
	Total Resources	7,752.6	7,943.2	7,924.3	7,921.6	7,960.1	7,997.1	8,036.4	8,057.9	8,059.6	8,038.5	7,995.9	8,006.1

Med Low Load - Med Gas

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,451	5,379	5,387	5,435	5,518	5,580	5,655	5,745	5,906	6,164	6,376	6,596
			Conservation (MWa)	6	11	17	22	28	35	41	52	80	135	185	252
			After Conservation												
			System Load (MWa)	5,446	5,368	5,370	5,412	5,489	5,545	5,614	5,693	5,825	6,029	6,191	6,344
	0.29		Energy Sales (MWa)	4,928	4,884	4,897	4,942	5,000	5,061	5,125	5,194	5,303	5,457	5,601	5,652
			Total Customers (000's)	1,278	1,281	1,287	1,298	1,311	1,324	1,337	1,351	1,377	1,417	1,452	1,474
			Net Electric Plant ($M)	8,040	8,196	8,338	8,509	8,639	8,786	8,939	9,109	9,489	10,141	10,869	12,098
			Net Conservation Assets ($M)	8	15	23	28	32	37	41	55	100	191	265	346
			Utility Cost												
38,921	3.11	Nominal	**Operating Revenues ($M)**	2,172	2,148	2,174	2,252	2,332	2,438	2,502	2,577	2,764	3,089	3,495	3,897
	-0.18	Real		2,172	2,079	2,038	2,043	2,048	2,072	2,059	2,053	2,064	2,092	2,148	2,103
	2.81	Nominal	Cost in mills/kWh	50.3	50.2	50.7	52.0	53.3	55.0	55.7	56.6	59.5	64.6	71.2	78.7
	-0.47	Real		50.3	48.6	47.5	47.2	46.8	46.7	45.9	45.1	44.4	43.8	43.8	42.5
		Nominal	Average Customer Bill ($)	1,700	1,677	1,689	1,735	1,779	1,841	1,871	1,908	2,007	2,180	2,408	2,644
		Real		1,700	1,623	1,583	1,574	1,562	1,565	1,540	1,520	1,499	1,477	1,480	1,427
			Total Resource Cost												
			DSR Customer Cost ($M)	-0.1	-0.3	-0.6	-0.9	-1.6	-3.1	-4.9	-6.3	-10.3	-18.9	-32.2	-58.4
			Levelized (20-year at 8.6%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			Energy Svc Charge ($M)	0.6	1.2	1.8	2.2	2.5	2.8	3.2	4.4	8.3	17.0	25.8	37.5
39,062	3.11	Nominal	**Total Resource Cost ($M)**	2,173	2,149	2,176	2,254	2,335	2,441	2,505	2,581	2,773	3,106	3,521	3,935
	-0.18	Real		2,173	2,080	2,039	2,045	2,051	2,075	2,062	2,057	2,070	2,104	2,164	2,123
	2.72	Nominal	Cost in mills/kWh	50.3	50.1	50.6	51.8	53.0	54.7	55.4	56.2	58.9	63.5	69.6	76.4
	-0.56	Real		50.3	48.5	47.4	47.0	46.6	46.5	45.6	44.8	44.0	43.0	42.8	41.2

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.92

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 43.03

Med Low Load - Med Gas

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	47,709	47,017	47,031	47,386	48,059	48,554	49,151	49,860	50,946	52,726	55,456	54,687
	MWa	5,446	5,367	5,369	5,409	5,486	5,543	5,611	5,692	5,816	6,019	6,331	6,243
	Total Annual Emissions (1000 Tons)												
0.50%	CO2	50,786	50,283	50,177	50,268	50,784	51,247	51,679	52,050	52,692	53,938	54,981	55,796
0.28%	NOx	120.5	119.9	119.9	119.6	120.4	121.3	124.6	124.9	125.4	126.2	126.5	127.0
0.22%	TSP	10.8	10.7	10.7	10.7	10.8	10.8	10.9	11.0	11.0	11.1	11.2	11.2
	Annual System Emission Rates (Pounds/MWh)												
-0.22%	CO2	2,129	2,139	2,134	2,122	2,113	2,111	2,103	2,088	2,069	2,046	1,983	2,041
-0.44%	NOx	5.05	5.10	5.10	5.05	5.01	5.00	5.07	5.01	4.92	4.79	4.56	4.65
-0.50%	TSP	0.45	0.45	0.46	0.45	0.45	0.45	0.44	0.44	0.43	0.42	0.40	0.41
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.47	100.22	99.66	99.27	99.15	98.77	98.07	97.16	96.10	93.14	95.85
	NOx	100	100.95	100.93	99.95	99.20	98.93	100.41	99.21	97.52	94.76	90.35	91.98
	TSP	100	100.58	100.80	100.07	98.98	98.81	98.24	97.18	95.70	93.42	89.16	90.90

20 Year Emissions (1000 Tons)	Average	Total
CO2	52,938	1,058,767
NOx	124.3	2,486
TSP	11.0	220

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Med High Load - Med Gas

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.9	23.0	23.5	23.8	24.5	24.7	24.7	24.9	48.9	73.4	69.3	85.8	463.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1					52.9		97.5	150.4					300.8
C	OWC Cogen 2							170.9	441.8	267.6	360.5			1240.8
	OWC Combined Cycle										134.4	791.2	249.7	1175.3
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**16.9**	**23.0**	**23.5**	**23.8**	**77.4**	**24.7**	**293.1**	**617.1**	**316.5**	**568.3**	**860.5**	**335.5**	**3180.3**
	DSM Programs	18.0	19.7	20.1	20.2	20.5	20.4	20.3	20.4	40.2	61.2	59.1	73.8	393.9
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1								8.4		28.3			36.7
U	Utah Cogen 2							2.1	197.4	195.3				394.8
T	Utah Combined Cycle										138.3	62.5		200.8
A	Utah Gadsby Repower					168.0	96.9	32.5						297.4
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4												400.0	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage											83.7		83.7
	Total	**18.0**	**19.7**	**20.1**	**20.2**	**188.5**	**117.3**	**54.9**	**226.2**	**235.5**	**227.8**	**205.3**	**473.8**	**1807.3**
	DSM Programs	6.4	7.0	7.0	7.1	7.2	7.2	7.1	7.2	14.2	21.6	20.8	25.8	138.6
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												39.8	39.8
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**6.4**	**7.0**	**7.0**	**7.1**	**7.2**	**7.2**	**7.1**	**7.2**	**14.2**	**21.6**	**20.8**	**65.6**	**178.4**
	DSM Programs	41.3	49.7	50.6	51.1	52.2	52.3	52.1	52.5	103.3	156.2	149.2	185.4	995.9
T	Renewable													0.0
O	Cogeneration					52.9		270.5	798.0	462.9	388.8			1973.1
T	Combined Cycle CT					168.0	96.9	32.5			272.7	853.7	249.7	1673.5
A	Coal & IGCC												439.8	439.8
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage											83.7		83.7
	Total	**41.3**	**49.7**	**50.6**	**51.1**	**273.1**	**149.2**	**355.1**	**850.5**	**566.2**	**817.7**	**1,086.6**	**874.9**	**5166.0**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,643	7,814	8,067	8,318	8,656	8,882	9,205	9,505	10,117	11,075	11,962	12,885
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(41)	(91)	(142)	(193)	(245)	(297)	(349)	(402)	(505)	(661)	(811)	(996)
T	**Total Requirements**	9,387	9,623	9,825	10,000	10,301	10,380	10,651	10,898	11,097	11,591	12,254	12,816
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,200	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources					221	318	621	1,419	1,882	2,543	3,481	4,170
&	Summer Purch $6/Year	277	38	201	393	500	500	500					
R	**Total Resources**	10,527	10,779	11,005	11,201	11,538	11,625	11,929	12,206	12,429	12,981	13,724	14,354
	Reserves	1,140	1,156	1,180	1,201	1,237	1,245	1,278	1,308	1,332	1,391	1,470	1,538
	Reserve Margin (RM) (%)	12.1	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Med High Load - Med Gas

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	22.9	30.7	32.0	32.7	33.8	34.3	34.4	34.9	68.7	102.9	94.9	115.5	637.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1					56.3		103.7	160.0					320.0
C	OWC Cogen 2							181.8	470.0	284.7	383.5			1320.0
	OWC Combined Cycle										143.0	841.7	265.6	1250.3
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**22.9**	**30.7**	**32.0**	**32.7**	**90.1**	**34.3**	**319.9**	**664.9**	**353.4**	**629.4**	**936.6**	**381.1**	**3528.0**
	DSM Programs	20.5	22.6	23.4	23.7	23.9	23.8	23.7	23.6	46.6	70.5	67.1	83.5	452.9
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1								8.9		30.1			39.0
U	Utah Cogen 2							2.2	210.0	207.8				420.0
T	Utah Combined Cycle										147.1	66.5		213.6
A	Utah Gadsby Repower					187.2	108.0	36.1						331.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4												400.0	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage											83.7		83.7
	Total	**20.5**	**22.6**	**23.4**	**23.7**	**211.1**	**131.8**	**62.0**	**242.5**	**254.4**	**247.7**	**217.3**	**483.5**	**1940.5**
	DSM Programs	5.7	6.1	6.2	6.3	6.3	6.4	6.4	6.4	12.6	19.2	18.3	22.5	122.4
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												39.8	39.8
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**5.7**	**6.1**	**6.2**	**6.3**	**6.3**	**6.4**	**6.4**	**6.4**	**12.6**	**19.2**	**18.3**	**62.3**	**162.2**
	DSM Programs	49.1	59.4	61.6	62.7	64.0	64.5	64.5	64.9	127.9	192.6	180.3	221.5	1213.0
T	Renewable													0.0
O	Cogeneration					56.3		287.7	848.9	492.5	413.6			2099.0
T	Combined Cycle CT					187.2	108.0	36.1			290.1	908.2	265.6	1795.2
A	Coal & IGCC												439.8	439.8
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage											83.7		83.7
	Total	**49.1**	**59.4**	**61.6**	**62.7**	**307.5**	**172.5**	**388.3**	**913.8**	**620.4**	**896.3**	**1,172.2**	**926.9**	**5630.7**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	8,073	8,252	8,408	8,690	8,975	9,267	9,566	9,896	10,473	11,487	12,352	13,504
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(49)	(109)	(170)	(233)	(297)	(361)	(426)	(491)	(619)	(811)	(992)	(1,213)
T	**Total Requirements**	**9,487**	**9,607**	**9,701**	**9,820**	**9,991**	**10,219**	**10,453**	**10,718**	**10,849**	**11,413**	**11,973**	**12,728**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,228	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources					244	352	675	1,524	2,017	2,720	3,712	4,418
&	Summer Purch $6/Year	277	38	201	393	500	500	500					
R	**Total Resources**	**10,625**	**10,888**	**11,221**	**11,434**	**11,770**	**11,870**	**12,195**	**12,540**	**12,497**	**13,036**	**13,874**	**14,556**
	Reserves	1,138	1,282	1,520	1,614	1,779	1,651	1,742	1,822	1,647	1,624	1,902	1,828
	Reserve Margin (RM) (%)	12.0	13.3	15.7	16.4	17.8	16.1	16.7	17.0	15.2	14.2	15.9	14.4

PacifiCorp RAMPP-4

Case # 22

Med High Load - Med Gas

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	11.2	25.6	40.4	55.4	70.8	86.5	102.1	117.8	148.9	195.5	239.5	293.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1					52.4	52.4	148.9	297.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2							169.2	595.6	817.8	1,188.5	1,223.0	1,227.1
	OWC Combined Cycle										62.6	418.8	531.2
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	11.2	25.6	40.4	55.4	123.2	138.8	420.2	1,011.3	1,264.5	1,744.5	2,179.1	2,349.9
	DSM Programs	13.2	27.3	41.6	56.1	70.7	85.3	99.9	114.5	143.3	187.2	229.6	282.7
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1								8.3	8.3	36.3	36.3	36.3
U	Utah Cogen 2							2.1	197.5	388.6	390.8	390.8	390.8
T	Utah Combined Cycle										67.5	127.0	140.9
A	Utah Gadsby Repower					152.7	237.5	252.3	211.0	163.0	185.3	246.3	255.9
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												366.6
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage											6.3	6.2
	Total	13.2	27.3	41.6	56.1	223.4	322.8	354.3	531.3	703.2	867.0	1,036.4	1,479.4
	DSM Programs	5.0	10.2	15.6	21.0	26.4	31.9	37.3	42.8	53.6	70.0	85.9	105.6
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												36.5
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	5.0	10.2	15.6	21.0	26.4	31.9	37.3	42.8	53.6	70.0	85.9	142.1
	DSM Programs	29.4	63.1	97.6	132.5	168.0	203.7	239.3	275.1	345.7	452.6	555.0	682.1
T	Renewable												
O	Cogeneration					52.4	52.4	320.2	1,099.2	1,512.6	1,913.5	1,948.0	1,952.1
T	Combined Cycle CT					152.7	237.5	252.3	211.0	163.0	315.4	792.1	928.0
A	Coal & IGCC												403.0
L	Transmission												
	Simple Cycle CT												
	Pumped Storage											6.3	6.2
	Total	29.4	63.1	97.6	132.5	373.0	493.5	811.8	1,585.3	2,021.2	2,681.5	3,301.4	3,971.4
S	**Native Load**	5,702.4	5,799.8	5,947.4	6,134.5	6,356.5	6,547.5	6,762.9	6,995.3	7,438.3	8,143.0	8,775.1	9,538.4
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	313.1	311.6
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	355.5	495.1	501.9	439.2	506.6	481.1	593.5	1,003.9	1,092.0	1,175.8	1,176.5	1,242.8
E	**DSM Programs**	(29.4)	(63.1)	(97.6)	(132.5)	(168.0)	(203.7)	(239.3)	(275.1)	(345.7)	(452.6)	(555.0)	(682.1)
M	**Total Requirements**	7,945.0	8,164.6	8,233.7	8,281.9	8,516.6	8,621.8	8,913.9	9,485.9	9,755.2	10,264.1	10,746.9	11,239.1
	Existing Generation	7,185.0	7,561.8	7,668.4	7,680.8	7,758.8	7,794.6	7,836.7	7,736.5	7,680.1	7,653.5	7,621.9	7,591.2
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	202.9	99.0	92.4	136.5	98.6	91.8	62.5					
R	**New Resources**					205.0	289.9	572.5	1,310.2	1,675.6	2,228.8	2,746.4	3,289.3
	Total Resources	7,945.0	8,164.6	8,233.7	8,281.9	8,516.6	8,621.8	8,913.9	9,485.8	9,755.2	10,264.1	10,746.9	11,239.0

Med High Load - Med Gas

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	6,012	6,110	6,257	6,445	6,667	6,858	7,073	7,305	7,748	8,453	9,085	9,848
			Conservation (MWa)	29	63	97	132	168	203	239	275	347	455	557	692
			After Conservation												
			System Load (MWa)	5,983	6,047	6,160	6,312	6,499	6,654	6,834	7,031	7,401	7,998	8,529	9,157
	0.77		Energy Sales (MWa)	5,399	5,466	5,566	5,698	5,843	5,995	6,151	6,322	6,643	7,141	7,621	7,858
			Total Customers (000's)	1,374	1,399	1,431	1,468	1,507	1,545	1,584	1,624	1,703	1,824	1,933	2,003
			Net Electric Plant ($M)	8,096	8,332	8,667	9,104	9,547	10,363	11,130	11,530	12,219	13,621	15,480	17,823
			Net Conservation Assets ($M)	63	137	211	260	306	349	391	430	499	576	614	681
			Utility Cost												
47,134	3.42	Nominal	**Operating Revenues ($M)**	2,278	2,260	2,332	2,458	2,528	2,677	2,786	2,916	3,336	3,849	4,496	5,169
	0.12	Real		2,278	2,188	2,185	2,230	2,220	2,275	2,293	2,324	2,491	2,607	2,763	2,790
	2.63	Nominal	Cost in mills/kWh	48.2	47.2	47.8	49.2	49.4	51.0	51.7	52.7	57.3	61.5	67.4	75.1
	-0.65	Real		48.2	45.7	44.8	44.7	43.4	43.3	42.6	42.0	42.8	41.7	41.4	40.5
		Nominal	Average Customer Bill ($)	1,658	1,615	1,629	1,675	1,677	1,732	1,759	1,796	1,959	2,110	2,326	2,581
		Real		1,658	1,563	1,527	1,519	1,473	1,472	1,448	1,431	1,462	1,429	1,430	1,393
			Total Resource Cost												
			DSR Customer Cost ($M)	1.0	2.8	4.6	9.0	13.0	16.6	20.1	23.2	27.3	27.9	23.0	3.7
			Levelized (20-year at 8.6%)	0.1	0.4	0.9	1.9	3.2	5.0	7.1	9.6	15.2	24.3	32.3	37.4
			Energy Svc Charge ($M)	5.6	12.6	20.0	24.5	29.2	34.1	39.0	44.2	54.9	72.3	85.3	89.2
47,849	3.42	Nominal	**Total Resource Cost ($M)**	2,283	2,273	2,353	2,484	2,560	2,716	2,832	2,970	3,406	3,946	4,614	5,296
	0.12	Real		2,283	2,200	2,205	2,254	2,248	2,309	2,331	2,366	2,543	2,673	2,835	2,858
	2.47	Nominal	Cost in mills/kWh	48.0	47.0	47.5	48.7	48.7	50.2	50.8	51.6	55.9	59.6	64.8	71.2
	-0.81	Real		48.0	45.5	44.5	44.2	42.8	42.6	41.8	41.1	41.7	40.4	39.8	38.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.31**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.64**

Med High Load - Med Gas

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	52,417	52,971	53,958	55,268	56,900	58,261	59,835	61,559	64,804	70,040	80,310	79,900
	MWa	5,984	6,047	6,160	6,309	6,495	6,651	6,831	7,027	7,398	7,995	9,168	9,121
	Total Annual Emissions (1000 Tons)												
0.01%	CO2	53,176	53,638	54,101	54,789	55,475	55,997	56,858	57,450	58,842	61,557	64,110	53,317
0.18%	NOx	121.8	122.6	123.1	123.5	123.3	123.1	126.6	126.1	126.0	126.7	127.4	126.0
0.39%	TSP	10.9	11.0	11.1	11.1	11.1	11.2	11.3	11.2	11.2	11.4	11.5	11.8
	Annual System Emission Rates (Pounds/MWh)												
-2.18%	CO2	2,029	2,025	2,005	1,983	1,950	1,922	1,900	1,867	1,816	1,758	1,597	1,335
-2.02%	NOx	4.65	4.63	4.56	4.47	4.34	4.23	4.23	4.10	3.89	3.62	3.17	3.15
-1.82%	TSP	0.42	0.42	0.41	0.40	0.39	0.38	0.38	0.36	0.35	0.32	0.29	0.29
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.82	98.83	97.72	96.10	94.74	93.67	91.99	89.50	86.63	78.69	65.78
	NOx	100	99.67	98.20	96.19	93.31	90.98	91.07	88.17	83.72	77.88	68.31	67.90
	TSP	100	99.62	98.25	96.36	93.76	91.75	90.09	87.32	83.06	77.73	68.42	70.60

20 Year Emissions (1000 Tons)	Average	Total
CO2	57,983	1,159,660
NOx	125.5	2,510
TSP	11.3	226

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Med Load - Low Gas

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	12.9	14.4	15.0	15.3	15.7	15.8	15.9	15.9	31.0	46.0	42.5	51.8	292.2
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1												300.8	300.8
C	OWC Cogen 2								78.0	265.6	294.6	484.0	118.6	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	12.9	14.4	15.0	15.3	15.7	15.8	15.9	93.9	296.6	340.6	526.5	471.2	1833.8
	DSM Programs	9.8	11.0	11.4	11.5	11.6	11.6	11.4	11.5	22.6	34.3	32.0	39.7	218.4
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											271.6	123.2	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower					1.1		128.3	168.0					297.4
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												40.3	40.3
	Total	9.8	11.0	11.4	11.5	12.7	11.6	139.7	179.5	22.6	34.3	303.6	203.2	950.9
	DSM Programs	3.4	3.7	3.8	3.9	4.0	4.0	3.9	4.0	7.8	11.9	11.1	13.6	75.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	3.4	3.7	3.8	3.9	4.0	4.0	3.9	4.0	7.8	11.9	11.1	13.6	75.1
	DSM Programs	26.1	29.1	30.2	30.7	31.3	31.4	31.2	31.4	61.4	92.2	85.6	105.1	585.7
T	Renewable													0.0
O	Cogeneration								78.0	265.6	294.6	755.6	542.6	1936.4
T	Combined Cycle CT					1.1		128.3	168.0					297.4
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												40.3	40.3
	Total	26.1	29.1	30.2	30.7	32.4	31.4	159.5	277.4	327.0	386.8	841.2	688.0	2859.8

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(26)	(55)	(85)	(116)	(147)	(179)	(210)	(241)	(303)	(395)	(481)	(586)
T	Total Requirements	9,028	9,161	9,272	9,382	9,603	9,611	9,792	9,967	9,989	10,155	10,655	11,123
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,207	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources					1	1	129	375	641	936	1,691	2,274
&	Summer Purch $6/Year							30					
R	Total Resources	10,250	10,741	10,804	10,808	10,818	10,809	10,967	11,162	11,188	11,374	11,934	12,458
	Reserves	1,222	1,580	1,532	1,426	1,215	1,198	1,175	1,196	1,199	1,219	1,279	1,335
	Reserve Margin (RM) (%)	13.5	17.2	16.5	15.2	12.7	12.5	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Low Gas

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.3	20.3	21.4	22.1	22.8	23.1	23.0	23.2	45.4	66.6	60.2	72.7	417.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1												320.0	320.0
C	OWC Cogen 2								83.0	282.5	313.4	514.9	126.2	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**16.3**	**20.3**	**21.4**	**22.1**	**22.8**	**23.1**	**23.0**	**106.2**	**327.9**	**380.0**	**575.1**	**518.9**	**2057.1**
	DSM Programs	12.2	13.7	14.6	14.6	14.8	14.6	14.4	14.5	28.3	42.5	39.0	47.8	271.0
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											288.9	131.1	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower					1.2		142.9	187.2					331.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												40.3	40.3
	Total	**12.2**	**13.7**	**14.6**	**14.6**	**16.0**	**14.6**	**157.3**	**201.7**	**28.3**	**42.5**	**327.9**	**219.2**	**1062.6**
	DSM Programs	2.9	3.3	3.4	3.5	3.5	3.6	3.5	3.6	7.1	10.7	9.7	11.9	66.7
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**2.9**	**3.3**	**3.4**	**3.5**	**3.5**	**3.6**	**3.5**	**3.6**	**7.1**	**10.7**	**9.7**	**11.9**	**66.7**
	DSM Programs	31.4	37.3	39.4	40.2	41.1	41.3	40.9	41.3	80.8	119.8	108.9	132.4	754.8
T	Renewable													0.0
O	Cogeneration								83.0	282.5	313.4	803.8	577.3	2060.0
T	Combined Cycle CT					1.2		142.9	187.2					331.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												40.3	40.3
	Total	**31.4**	**37.3**	**39.4**	**40.2**	**42.3**	**41.3**	**183.8**	**311.5**	**363.3**	**433.2**	**912.7**	**750.0**	**3186.4**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(31)	(69)	(108)	(148)	(189)	(231)	(272)	(313)	(394)	(514)	(622)	(755)
T	**Total Requirements**	**9,001**	**9,025**	**9,091**	**9,109**	**9,209**	**9,361**	**9,519**	**9,694**	**9,705**	**9,956**	**10,334**	**10,767**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,228	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources					1	1	144	414	697	1,010	1,814	2,432
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,028**	**11,019**	**11,164**	**11,430**	**11,177**	**11,326**	**11,976**	**12,570**
	Reserves	1,347	1,825	1,929	1,932	1,819	1,658	1,645	1,736	1,472	1,371	1,642	1,802
	Reserve Margin (RM) (%)	15.0	20.2	21.2	21.2	19.8	17.7	17.3	17.9	15.2	13.8	15.9	16.7

Med Load - Low Gas

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	7.9	16.9	26.1	35.6	45.3	55.2	65.0	74.9	94.1	122.7	149.0	181.1
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												297.9
W	OWC Cogen 1								77.2	340.1	631.7	1,103.8	1,201.3
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	7.9	16.9	26.1	35.6	45.3	55.2	65.0	152.1	434.3	754.4	1,252.8	1,680.2
	DSM Programs	6.6	13.9	21.4	29.0	36.6	44.3	51.8	59.4	74.4	97.1	118.3	144.6
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1											268.8	390.8
U	Utah Cogen 2												
T	Utah Combined Cycle												
A	Utah Gadsby Repower					1.0	1.0	112.3	255.0	266.3	286.0	259.8	212.7
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												4.8
	Utah Pumped Storage												
	Total	6.6	13.9	21.4	29.0	37.6	45.2	164.1	314.4	340.7	383.1	646.9	752.9
	DSM Programs	2.3	5.0	7.6	10.4	13.1	15.9	18.7	21.5	27.0	35.3	43.1	52.7
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	2.3	5.0	7.6	10.4	13.1	15.9	18.7	21.5	27.0	35.3	43.1	52.7
	DSM Programs	16.9	35.7	55.1	74.9	95.1	115.3	135.5	155.7	195.5	255.1	310.4	378.4
T	Renewable												
O	Cogeneration								77.2	340.1	631.7	1,372.6	1,889.9
T	Combined Cycle CT					1.0	1.0	112.3	255.0	266.3	286.0	259.8	212.7
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												4.8
	Pumped Storage												
	Total	16.9	35.7	55.1	74.9	96.1	116.3	247.8	487.9	801.9	1,172.8	1,942.8	2,485.9
S	Native Load	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	Pump Storage/Peak Return	310.6	310.1	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	311.2
S	Firm Sales	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	Non-Firm Sales	495.7	748.1	757.5	714.7	640.1	581.5	579.4	697.2	860.3	878.3	1,094.2	1,239.3
E	DSM Programs	(16.9)	(35.7)	(55.1)	(74.9)	(95.1)	(115.3)	(135.5)	(155.7)	(195.5)	(255.1)	(310.4)	(378.4)
M	Total Requirements	7,809.5	8,062.0	8,068.6	8,075.8	8,114.5	8,133.1	8,253.5	8,471.6	8,697.9	8,953.1	9,476.6	9,832.7
	Existing Generation	7,161.5	7,513.2	7,544.0	7,555.7	7,601.4	7,607.6	7,628.6	7,648.6	7,671.7	7,641.0	7,465.2	7,366.2
L	Firm Purchases	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	Non-Firm Purchases	91.0	45.1	51.7	55.5	58.1	79.0	70.3	51.7	20.2	12.7	0.3	0.5
R	New Resources					1.0	1.0	112.3	332.2	606.4	917.7	1,632.4	2,107.5
	Total Resources	7,809.5	8,062.0	8,068.6	8,075.8	8,114.5	8,133.1	8,253.5	8,471.5	8,697.9	8,953.1	9,476.6	9,832.6

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Med Load - Low Gas

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	17	35	55	74	94	115	135	155	195	255	310	381
			After Conservation												
			System Load (MWa)	5,707	5,692	5,740	5,831	5,964	6,065	6,188	6,324	6,577	6,987	7,351	7,761
	0.55		Energy Sales (MWa)	5,158	5,170	5,235	5,331	5,438	5,548	5,662	5,776	5,955	6,213	6,553	6,727
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,071	8,261	8,438	8,643	8,886	9,278	9,632	9,935	10,484	11,475	13,173	15,350
			Net Conservation Assets ($M)	39	80	122	152	181	208	233	256	298	342	362	397
			Utility Cost												
42,649	3.29	Nominal	Operating Revenues ($M)	2,212	2,200	2,241	2,333	2,431	2,557	2,607	2,671	2,939	3,360	3,880	4,550
	-0.01	Real		2,212	2,130	2,100	2,116	2,135	2,174	2,145	2,128	2,194	2,276	2,384	2,456
	2.72	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.0	51.0	52.6	52.6	52.8	56.3	61.7	67.6	77.2
	-0.56	Real		49.0	47.0	45.8	45.3	44.8	44.7	43.3	42.1	42.1	41.8	41.5	41.7
		Nominal	Average Customer Bill ($)	1,668	1,643	1,651	1,691	1,730	1,790	1,796	1,809	1,928	2,102	2,327	2,658
		Real		1,668	1,590	1,547	1,534	1,520	1,522	1,478	1,441	1,439	1,423	1,430	1,434
			Total Resource Cost												
			DSR Customer Cost ($M)	0.6	1.3	1.9	3.6	4.9	5.8	6.3	6.1	3.7	-6.5	-23.3	-58.7
			Levelized (20-year at 8.6%)	0.1	0.2	0.4	0.8	1.3	1.9	2.6	3.3	4.2	4.3	4.3	4.3
			Energy Svc Charge ($M)	3.2	6.8	10.6	13.2	15.8	18.5	21.3	24.1	30.1	39.6	46.4	48.5
42,973	3.28	Nominal	Total Resource Cost ($M)	2,216	2,207	2,252	2,347	2,448	2,577	2,631	2,698	2,973	3,404	3,931	4,603
	-0.02	Real		2,216	2,137	2,110	2,129	2,150	2,191	2,165	2,150	2,220	2,306	2,415	2,484
	2.61	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.6	50.6	52.0	51.9	52.1	55.3	60.3	65.6	74.3
	-0.67	Real		48.9	46.9	45.6	45.0	44.4	44.2	42.7	41.5	41.3	40.8	40.3	40.1

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.21**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.05**

Med Load - Low Gas

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	50,002	49,856	50,273	51,049	52,208	53,100	54,174	55,360	57,572	61,162	68,021	67,808
	MWa	5,708	5,691	5,739	5,828	5,960	6,062	6,184	6,320	6,572	6,982	7,765	7,741
	Total Annual Emissions (1000 Tons)												
-0.05%	CO2	51,963	51,967	52,104	52,561	53,295	53,737	54,033	54,207	55,259	57,203	58,615	51,480
0.05%	NOx	121.1	121.5	121.8	122.2	123.0	123.2	125.2	124.0	124.3	124.8	123.8	122.2
0.07%	TSP	10.9	10.9	10.9	11.0	11.0	11.1	11.0	11.0	11.0	11.1	11.0	11.0
	Annual System Emission Rates (Pounds/MWh)												
-1.64%	CO2	2,078	2,085	2,073	2,059	2,042	2,024	1,995	1,958	1,920	1,871	1,723	1,518
-1.54%	NOx	4.85	4.87	4.84	4.79	4.71	4.64	4.62	4.48	4.32	4.08	3.64	3.61
-1.52%	TSP	0.43	0.44	0.43	0.43	0.42	0.42	0.41	0.40	0.38	0.36	0.32	0.32
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.30	99.73	99.08	98.23	97.38	95.98	94.22	92.36	90.00	82.92	73.06
	NOx	100	100.57	99.96	98.77	97.21	95.78	95.40	92.46	89.12	84.20	75.10	74.41
	TSP	100	100.39	99.84	98.74	97.17	95.89	93.85	91.26	88.14	83.68	74.62	74.73

20 Year Emissions (1000 Tons)

	Average	Total
CO2	54,729	1,094,581
NOx	123.4	2,468
TSP	11.0	220

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Med Load - Med Gas
with Limited Gas (500 MW) at Med Esc

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	20.7	21.2	21.3	21.3	21.4	41.8	62.5	58.9	73.2	388.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1							100.4	150.4	50.0				300.8
C	OWC Cogen 2								47.3	23.0	128.7	565.0		764.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.3**	**15.7**	**16.1**	**20.7**	**21.2**	**21.3**	**121.7**	**219.1**	**114.8**	**191.2**	**623.9**	**73.2**	**1453.2**
	DSM Programs	13.4	14.2	14.6	14.7	14.9	14.7	14.7	14.7	29.0	44.0	41.7	51.9	282.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2									170.0	131.7	20.6		322.3
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											135.7	264.3	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												60.9	60.9
	Total	**13.4**	**14.2**	**14.6**	**14.7**	**14.9**	**14.7**	**14.7**	**14.7**	**199.0**	**175.7**	**198.0**	**377.1**	**1065.7**
	DSM Programs	5.1	5.1	5.3	5.4	5.4	5.4	5.5	5.4	10.7	16.3	15.4	19.0	104.0
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												214.3	214.3
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**5.1**	**5.1**	**5.3**	**5.4**	**5.4**	**5.4**	**5.5**	**5.4**	**10.7**	**16.3**	**15.4**	**233.3**	**318.3**
	DSM Programs	32.8	35.0	36.0	40.8	41.5	41.4	41.5	41.5	81.5	122.8	116.0	144.1	774.9
T	Renewable													0.0
O	Cogeneration							100.4	197.7	243.0	260.4	585.6		1387.1
T	Combined Cycle CT													0.0
A	Coal & IGCC											135.7	478.6	614.3
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												60.9	60.9
	Total	**32.8**	**35.0**	**36.0**	**40.8**	**41.5**	**41.4**	**141.9**	**239.2**	**324.5**	**383.2**	**837.3**	**683.6**	**2837.2**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(68)	(104)	(145)	(186)	(228)	(269)	(311)	(392)	(515)	(631)	(775)
T	Total Requirements	9,021	9,148	9,253	9,353	9,564	9,563	9,733	9,898	9,900	10,035	10,505	10,934
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							100	298	541	802	1,523	2,062
&	Summer Purch $6/Year												
R	Total Resources	10,250	10,741	10,804	10,808	10,817	10,808	10,908	11,085	11,088	11,240	11,766	12,246
	Reserves	1,229	1,593	1,551	1,455	1,253	1,246	1,175	1,188	1,188	1,204	1,261	1,312
	Reserve Margin (RM) (%)	13.6	17.4	16.8	15.5	13.1	13.0	12.1	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with Limited Gas (500 MW) at Med Esc

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	27.0	27.8	28.3	28.1	28.5	55.6	82.3	75.7	92.7	509.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1							106.8	160.0	53.2				320.0
C	OWC Cogen 2								50.3	24.5	136.9	601.0		812.7
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.4**	**21.8**	**22.9**	**27.0**	**27.8**	**28.3**	**134.9**	**238.8**	**133.3**	**219.2**	**676.7**	**92.7**	**1641.8**
	DSM Programs	15.7	16.9	17.7	17.8	18.0	17.9	17.6	17.7	34.7	52.5	49.0	60.6	336.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2									180.8	140.1	22.0		342.9
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											135.7	264.3	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												60.9	60.9
	Total	**15.7**	**16.9**	**17.7**	**17.8**	**18.0**	**17.9**	**17.6**	**17.7**	**215.5**	**192.6**	**206.7**	**385.8**	**1139.9**
	DSM Programs	4.6	4.7	4.9	4.9	5.0	5.1	5.0	5.0	10.0	15.0	14.1	17.3	95.6
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												214.3	214.3
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.6**	**4.7**	**4.9**	**4.9**	**5.0**	**5.1**	**5.0**	**5.0**	**10.0**	**15.0**	**14.1**	**231.6**	**309.9**
	DSM Programs	38.7	43.4	45.5	49.7	50.8	51.3	50.7	51.2	100.3	149.8	138.8	170.6	940.8
T	Renewable													0.0
O	Cogeneration							106.8	210.3	258.5	277.0	623.0		1475.6
T	Combined Cycle CT													0.0
A	Coal & IGCC											135.7	478.6	614.3
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												60.9	60.9
	Total	**38.7**	**43.4**	**45.5**	**49.7**	**50.8**	**51.3**	**157.5**	**261.5**	**358.8**	**426.8**	**897.5**	**710.1**	**3091.6**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(82)	(128)	(177)	(228)	(279)	(330)	(381)	(482)	(631)	(770)	(941)
T	**Total Requirements**	**8,993**	**9,012**	**9,071**	**9,080**	**9,170**	**9,313**	**9,461**	**9,626**	**9,617**	**9,838**	**10,186**	**10,581**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							107	317	576	853	1,611	2,151
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,127**	**11,333**	**11,056**	**11,169**	**11,773**	**12,289**
	Reserves	1,355	1,838	1,949	1,961	1,856	1,705	1,666	1,707	1,438	1,331	1,588	1,708
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.6	20.2	18.3	17.6	17.7	15.0	13.5	15.6	16.1

Med Load - Med Gas
with Limited Gas (500 MW) at Med Esc

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	42.4	55.4	68.6	81.7	94.9	120.7	159.3	195.6	240.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1							99.4	248.3	297.9	297.9	297.9	297.9
C	OWC Cogen 2								46.8	69.6	195.1	697.2	673.3
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.3**	**19.3**	29.7	**42.4**	55.4	**68.6**	**181.1**	**390.1**	**488.2**	**652.3**	**1,190.7**	**1,211.8**
	DSM Programs	9.8	20.2	30.9	41.7	52.5	63.3	74.0	84.8	106.1	138.5	169.4	208.0
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2									165.3	276.2	290.5	276.2
T	Utah Combined Cycle												
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4											124.4	366.6
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												9.2
	Total	**9.8**	**20.2**	30.9	**41.7**	52.5	**63.3**	**74.0**	**84.8**	**271.4**	**414.7**	584.3	**860.0**
	DSM Programs	3.9	7.9	12.1	16.3	20.5	24.7	29.0	33.2	41.6	54.2	66.4	81.5
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												196.4
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.9**	**7.9**	**12.1**	**16.3**	**20.5**	**24.7**	**29.0**	**33.2**	**41.6**	**54.2**	**66.4**	**277.8**
	DSM Programs	23.0	47.5	72.7	100.3	128.4	156.6	184.7	212.9	268.4	352.1	431.5	530.1
T	Renewable												
O	Cogeneration							99.4	295.2	532.7	769.2	1,285.6	1,247.3
T	Combined Cycle CT												
A	Coal & IGCC											124.4	562.9
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												9.2
	Total	**23.0**	**47.5**	**72.7**	**100.3**	**128.4**	**156.6**	**284.1**	**508.1**	**801.1**	**1,121.2**	**1,841.4**	**2,349.6**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	316.8
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	498.8	759.9	827.3	798.4	734.4	720.1	699.8	800.7	925.5	935.5	1,129.6	1,240.3
E	**DSM Programs**	(23.0)	(47.5)	(72.7)	(100.3)	(128.4)	(156.6)	(184.7)	(212.9)	(268.4)	(352.0)	(431.5)	(530.1)
M	**Total Requirements**	7,806.4	8,062.2	8,120.8	8,134.1	8,175.5	8,230.5	8,324.7	8,517.9	8,690.2	8,913.3	9,390.9	9,687.6
	Existing Generation	7,161.0	7,521.7	7,608.6	7,640.3	7,669.4	7,718.5	7,740.8	7,749.3	7,748.2	7,736.9	7,602.3	7,509.6
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	88.4	36.7	39.3	29.1	52.0	66.5	42.3	34.3	9.8	25.5		
R	**New Resources**							99.4	295.2	532.7	769.2	1,410.0	1,819.4
	Total Resources	7,806.4	8,062.2	8,120.8	8,134.1	8,175.5	8,230.5	8,324.8	8,517.9	8,690.2	8,913.3	9,390.9	9,687.5

Med Load - Med Gas

with Limited Gas (500 MW) at Med Esc

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	47	72	100	128	156	184	212	269	353	432	536
			After Conservation												
			System Load (MWa)	5,701	5,680	5,722	5,805	5,930	6,024	6,139	6,266	6,504	6,889	7,229	7,606
	0.51		Energy Sales (MWa)	5,152	5,159	5,219	5,307	5,407	5,510	5,616	5,723	5,887	6,122	6,441	6,584
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,284	8,471	8,686	8,936	9,340	9,712	10,039	10,632	11,725	13,621	16,068
			Net Conservation Assets ($M)	51	103	156	196	234	271	305	337	395	460	493	546
			Utility Cost												
41,924	3.17	Nominal	**Operating Revenues ($M)**	2,211	2,195	2,234	2,322	2,416	2,537	2,618	2,732	2,963	3,362	3,828	4,334
	-0.12	Real		2,211	2,125	2,093	2,107	2,122	2,157	2,154	2,177	2,212	2,277	2,352	2,339
	2.65	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.0	51.0	52.6	53.2	54.5	57.5	62.7	67.9	75.1
	-0.63	Real		49.0	47.0	45.8	45.3	44.8	44.7	43.8	43.4	42.9	42.5	41.7	40.6
		Nominal	Average Customer Bill ($)	1,667	1,639	1,646	1,683	1,720	1,777	1,803	1,851	1,943	2,102	2,296	2,532
		Real		1,667	1,587	1,542	1,527	1,510	1,511	1,484	1,475	1,451	1,424	1,411	1,366
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.7	5.9	8.8	11.4	13.8	15.7	17.7	15.6	8.7	-10.8
			Levelized (20-year at 8.6%)	0.1	0.3	0.5	1.2	2.1	3.3	4.8	6.5	10.2	15.5	19.1	19.7
			Energy Svc Charge ($M)	4.5	9.3	14.4	18.0	21.8	25.7	29.7	33.9	42.5	56.4	66.8	71.4
42,445	3.17	Nominal	**Total Resource Cost ($M)**	2,216	2,205	2,249	2,341	2,440	2,567	2,652	2,773	3,016	3,434	3,914	4,425
	-0.13	Real		2,216	2,134	2,107	2,124	2,143	2,182	2,183	2,209	2,251	2,326	2,405	2,388
	2.49	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.5	50.4	51.8	52.3	53.5	56.1	60.8	65.4	71.4
	-0.78	Real		48.9	46.8	45.5	44.9	44.3	44.1	43.1	42.6	41.9	41.2	40.2	38.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.11**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.54**

Med Load - Med Gas
with Limited Gas (500 MW) at Med Esc

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,948	49,754	50,119	50,826	51,916	52,739	53,743	54,860	56,933	60,312	66,741	66,398
	MWa	5,702	5,680	5,721	5,802	5,926	6,020	6,135	6,263	6,499	6,885	7,619	7,580
	Total Annual Emissions (1000 Tons)												
0.18%	CO2	51,936	51,973	52,148	52,625	53,294	53,771	54,266	54,795	55,689	57,608	59,880	53,728
0.22%	NOx	121.1	121.6	122.0	122.6	123.3	123.7	126.8	127.0	127.0	127.7	130.1	126.3
0.37%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.4	11.7
	Annual System Emission Rates (Pounds/MWh)												
-1.31%	CO2	2,080	2,089	2,081	2,071	2,053	2,039	2,019	1,998	1,956	1,910	1,794	1,618
-1.27%	NOx	4.85	4.89	4.87	4.82	4.75	4.69	4.72	4.63	4.46	4.24	3.90	3.81
-1.12%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.42	0.41	0.39	0.37	0.34	0.35
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.46	100.07	99.57	98.72	98.05	97.11	96.06	94.07	91.86	86.28	77.82
	NOx	100	100.81	100.41	99.45	97.93	96.74	97.32	95.49	91.99	87.33	80.38	78.45
	TSP	100	100.67	100.33	99.50	97.93	96.92	95.46	93.79	90.45	86.19	78.58	80.72

20 Year Emissions (1000 Tons)

	Average	Total
CO2	55,408	1,108,156
NOx	126.2	2,524
TSP	11.2	225

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Case # 33

Med Load - High Gas

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	20.7	21.2	21.3	21.3	21.4	41.8	62.5	58.9	73.2	388.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1							88.2	150.4	62.2				300.8
C	OWC Cogen 2								53.0	152.9	213.2	488.2		907.3
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.3**	**15.7**	**16.1**	**20.7**	**21.2**	**21.3**	**109.5**	**224.8**	**256.9**	**275.7**	**547.1**	**73.2**	**1596.5**
	DSM Programs	13.4	14.2	14.6	14.7	14.9	14.7	14.7	14.7	29.0	44.0	41.7	51.9	282.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1										36.7			36.7
U	Utah Cogen 2									25.4	6.8	1.3		33.5
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											228.1	171.9	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												98.5	98.5
	Total	**13.4**	**14.2**	**14.6**	**14.7**	**14.9**	**14.7**	**14.7**	**14.7**	**54.4**	**87.5**	**271.1**	**322.3**	**851.2**
	DSM Programs	5.1	5.2	5.4	6.4	6.6	6.5	6.6	6.5	13.0	19.6	18.8	23.4	123.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												264.0	264.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**5.1**	**5.2**	**5.4**	**6.4**	**6.6**	**6.5**	**6.6**	**6.5**	**13.0**	**19.6**	**18.8**	**287.4**	**387.1**
	DSM Programs	32.8	35.1	36.1	41.8	42.7	42.5	42.6	42.6	83.8	126.1	119.4	148.5	794.0
T	Renewable													0.0
O	Cogeneration							88.2	203.4	240.5	256.7	489.5		1278.3
T	Combined Cycle CT													0.0
A	Coal & IGCC											228.1	435.9	664.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												98.5	98.5
	Total	**32.8**	**35.1**	**36.1**	**41.8**	**42.7**	**42.5**	**130.8**	**246.0**	**324.3**	**382.8**	**837.0**	**682.9**	**2834.8**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	**Native Load**	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	**Firm Sales**	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(68)	(104)	(146)	(189)	(231)	(274)	(316)	(400)	(526)	(646)	(794)
T	**Total Requirements**	9,021	9,148	9,253	9,352	9,562	9,559	9,728	9,892	9,892	10,024	10,491	10,915
E													
M	**Existing Generation**	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							88	292	532	789	1,506	2,041
&	Summer Purch $6/Year												
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,896	11,079	11,079	11,227	11,749	12,225
	Reserves	1,229	1,593	1,551	1,456	1,256	1,249	1,168	1,187	1,187	1,203	1,259	1,310
	Reserve Margin (RM) (%)	13.6	17.4	16.8	15.6	13.1	13.1	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - High Gas

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	27.0	27.8	28.3	28.1	28.5	55.6	82.3	75.7	92.7	509.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1							93.8	160.0	66.2				320.0
C	OWC Cogen 2								56.4	162.7	226.8	519.3		965.2
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.4**	**21.8**	**22.9**	**27.0**	**27.8**	**28.3**	**121.9**	**244.9**	**284.5**	**309.1**	**595.0**	**92.7**	**1794.3**
	DSM Programs	15.7	16.9	17.7	17.8	18.0	17.9	17.6	17.8	34.8	52.5	49.1	60.6	336.4
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1										39.0			39.0
U	Utah Cogen 2									27.1	7.2	1.3		35.6
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											228.1	171.9	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												98.5	98.5
	Total	**15.7**	**16.9**	**17.7**	**17.8**	**18.0**	**17.9**	**17.6**	**17.8**	**61.9**	**98.7**	**278.5**	**331.0**	**909.5**
	DSM Programs	4.6	4.8	4.9	5.5	5.6	5.6	5.8	5.8	11.5	18.0	17.4	22.3	111.8
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												264.0	264.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.6**	**4.8**	**4.9**	**5.5**	**5.6**	**5.6**	**5.8**	**5.8**	**11.5**	**18.0**	**17.4**	**286.3**	**375.8**
	DSM Programs	38.7	43.5	45.5	50.3	51.4	51.8	51.5	52.1	101.9	152.8	142.2	175.6	957.3
T	Renewable													0.0
O	Cogeneration							93.8	216.4	256.0	273.0	520.6		1359.8
T	Combined Cycle CT													0.0
A	Coal & IGCC											228.1	435.9	664.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												98.5	98.5
	Total	**38.7**	**43.5**	**45.5**	**50.3**	**51.4**	**51.8**	**145.3**	**268.5**	**357.9**	**425.8**	**890.9**	**710.0**	**3079.6**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(82)	(128)	(178)	(229)	(281)	(333)	(385)	(487)	(640)	(782)	(957)
T	**Total Requirements**	**8,993**	**9,012**	**9,071**	**9,079**	**9,169**	**9,311**	**9,458**	**9,622**	**9,612**	**9,830**	**10,174**	**10,565**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							94	310	566	839	1,588	2,122
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,114**	**11,326**	**11,046**	**11,155**	**11,750**	**12,260**
	Reserves	1,355	1,838	1,949	1,962	1,857	1,707	1,656	1,704	1,434	1,326	1,576	1,696
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.6	20.3	18.3	17.5	17.7	14.9	13.5	15.5	16.0

Med Load - High Gas

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	42.4	55.4	68.6	81.7	94.9	120.7	159.3	195.6	240.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1							87.3	236.3	297.9	297.9	297.9	297.9
C	OWC Cogen 2								52.4	203.9	399.5	824.2	803.7
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.3**	**19.3**	**29.7**	**42.4**	**55.4**	**68.6**	**169.0**	**383.6**	**622.5**	**856.7**	**1,317.7**	**1,342.2**
	DSM Programs	9.8	20.2	30.9	41.7	52.5	63.3	74.1	84.9	106.2	138.6	169.6	208.2
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1										36.3	36.3	34.9
U	Utah Cogen 2									22.9	30.0	30.2	28.7
T	Utah Combined Cycle												
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4											209.0	366.6
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												17.5
	Total	**9.8**	**20.2**	**30.9**	**41.7**	**52.5**	**63.3**	**74.1**	**84.9**	**129.1**	**204.8**	**445.1**	**655.8**
	DSM Programs	3.9	8.1	12.2	16.9	21.6	26.4	31.2	36.0	45.5	60.2	74.4	92.5
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												241.9
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.9**	**8.1**	**12.2**	**16.9**	**21.6**	**26.4**	**31.2**	**36.0**	**45.5**	**60.2**	**74.4**	**334.4**
	DSM Programs	23.0	47.6	72.8	101.0	129.6	158.2	186.9	215.7	272.4	358.1	439.6	541.3
T	Renewable												
O	Cogeneration							87.3	288.7	524.7	763.7	1,188.6	1,165.2
T	Combined Cycle CT												
A	Coal & IGCC											209.0	608.5
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												17.5
	Total	**23.0**	**47.6**	**72.8**	**101.0**	**129.6**	**158.2**	**274.3**	**504.5**	**797.1**	**1,121.7**	**1,837.2**	**2,332.5**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	327.4
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	493.6	760.4	827.3	798.7	734.9	714.8	693.9	799.0	927.0	934.3	1,124.2	1,241.9
E	**DSM Programs**	(23.0)	(47.6)	(72.8)	(101.0)	(129.5)	(158.2)	(186.9)	(215.7)	(272.4)	(358.1)	(439.6)	(541.3)
M	**Total Requirements**	7,801.2	8,062.6	8,120.7	8,133.7	8,174.8	8,223.4	8,316.6	8,513.3	8,687.7	8,906.1	9,377.4	9,688.5
	Existing Generation	7,161.0	7,521.7	7,608.6	7,640.1	7,668.8	7,718.1	7,741.0	7,749.1	7,751.1	7,736.0	7,601.0	7,538.8
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	83.2	37.1	39.2	28.9	52.0	59.8	46.0	36.4	12.4	24.7	0.2	
R	**New Resources**							87.3	288.7	524.7	763.7	1,397.6	1,791.1
	Total Resources	7,801.2	8,062.6	8,120.7	8,133.7	8,174.8	8,223.4	8,316.6	8,513.3	8,687.7	8,906.1	9,377.4	9,688.5

Med Load - High Gas

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	47	72	100	129	158	186	215	273	360	441	548
			After Conservation												
			System Load (MWa)	5,701	5,680	5,722	5,805	5,929	6,022	6,136	6,263	6,499	6,882	7,220	7,594
	0.51		Energy Sales (MWa)	5,152	5,159	5,219	5,307	5,406	5,508	5,614	5,720	5,883	6,116	6,432	6,573
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,284	8,472	8,686	8,930	9,326	9,703	10,024	10,616	11,798	13,717	16,165
			Net Conservation Assets ($M)	51	103	157	198	237	275	311	345	408	480	520	581
			Utility Cost												
42,457	3.22	Nominal	**Operating Revenues ($M)**	2,211	2,195	2,234	2,322	2,416	2,537	2,619	2,733	3,000	3,425	3,893	4,432
	-0.08	Real		2,211	2,125	2,093	2,106	2,122	2,157	2,155	2,178	2,240	2,320	2,392	2,392
	2.70	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.0	51.0	52.6	53.3	54.5	58.2	63.9	69.1	77.0
	-0.58	Real		49.0	47.0	45.8	45.3	44.8	44.7	43.8	43.5	43.5	43.3	42.5	41.5
		Nominal	Average Customer Bill ($)	1,667	1,639	1,646	1,683	1,720	1,777	1,804	1,851	1,968	2,142	2,335	2,589
		Real		1,667	1,587	1,542	1,527	1,510	1,510	1,485	1,475	1,469	1,451	1,434	1,397
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.7	6.1	9.1	11.9	14.0	15.9	18.0	16.3	9.9	-8.5
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.2	2.2	3.4	4.9	6.6	10.4	15.9	19.9	20.8
			Energy Svc Charge ($M)	4.5	9.3	14.4	18.2	22.1	26.2	30.4	34.7	43.7	58.1	69.1	74.2
42,995	3.22	Nominal	**Total Resource Cost ($M)**	2,216	2,205	2,249	2,341	2,441	2,567	2,654	2,774	3,054	3,499	3,982	4,527
	-0.08	Real		2,216	2,134	2,107	2,124	2,143	2,182	2,184	2,210	2,280	2,370	2,447	2,443
	2.54	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.5	50.4	51.8	52.4	53.5	56.8	62.0	66.5	73.0
	-0.73	Real		48.9	46.8	45.5	44.9	44.3	44.1	43.1	42.6	42.4	42.0	40.9	39.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.69

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.07

Med Load - High Gas

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,948	49,753	50,118	50,820	51,906	52,724	53,724	54,834	56,898	60,259	66,735	66,319
	MWa	5,702	5,680	5,721	5,801	5,925	6,019	6,133	6,260	6,495	6,879	7,618	7,571
	Total Annual Emissions (1000 Tons)												
0.20%	CO2	51,936	51,972	52,148	52,622	53,288	53,762	54,257	54,782	55,713	57,592	60,252	53,930
0.24%	NOx	121.1	121.6	122.0	122.6	123.3	123.7	126.8	127.0	127.1	127.8	131.6	126.7
0.40%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.4	11.7
	Annual System Emission Rates (Pounds/MWh)												
-1.29%	CO2	2,080	2,089	2,081	2,071	2,053	2,039	2,020	1,998	1,958	1,911	1,806	1,626
-1.25%	NOx	4.85	4.89	4.87	4.82	4.75	4.69	4.72	4.63	4.47	4.24	3.94	3.82
-1.09%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.42	0.41	0.39	0.38	0.34	0.35
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.46	100.07	99.58	98.73	98.06	97.13	96.08	94.17	91.91	86.83	78.20
	NOx	100	100.81	100.41	99.46	97.94	96.76	97.35	95.53	92.13	87.42	81.32	78.76
	TSP	100	100.67	100.34	99.51	97.95	96.95	95.49	93.82	90.62	86.30	78.81	81.23

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,496	1,109,926
NOx	126.5	2,530
TSP	11.3	225

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Med Load - High Gas
with Medium Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	20.4	20.7	21.1	21.4	21.3	21.4	41.8	62.5	58.9	73.2	392.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2								111.0	80.8	242.1	407.8		841.7
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.3**	**15.7**	**20.4**	**20.7**	**21.1**	**21.4**	**21.3**	**282.8**	**273.0**	**304.6**	**466.7**	**73.2**	**1535.2**
	DSM Programs	13.4	14.2	14.6	19.0	19.2	19.1	19.0	19.0	37.5	57.0	54.6	68.9	355.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2													0.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											295.4	104.6	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												146.8	146.8
	Total	**13.4**	**14.2**	**14.6**	**19.0**	**19.2**	**19.1**	**19.0**	**19.0**	**37.5**	**57.0**	**350.0**	**320.3**	**902.3**
	DSM Programs	5.1	5.1	6.4	6.5	6.6	6.5	6.6	6.5	12.9	19.7	18.8	23.4	124.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												264.0	264.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**5.1**	**5.1**	**6.4**	**6.5**	**6.6**	**6.5**	**6.6**	**6.5**	**12.9**	**19.7**	**18.8**	**287.4**	**388.1**
	DSM Programs	32.8	35.0	41.4	46.2	46.9	47.0	46.9	46.9	92.2	139.2	132.3	165.5	872.3
T	Renewable													0.0
O	Cogeneration								261.4	231.2	242.1	407.8		1142.5
T	Combined Cycle CT													0.0
A	Coal & IGCC											295.4	368.6	664.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												146.8	146.8
	Total	**32.8**	**35.0**	**41.4**	**46.2**	**46.9**	**47.0**	**46.9**	**308.3**	**323.4**	**381.3**	**835.5**	**680.9**	**2825.6**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(68)	(109)	(155)	(202)	(249)	(296)	(343)	(435)	(575)	(707)	(872)
T	**Total Requirements**	**9,021**	**9,148**	**9,248**	**9,343**	**9,548**	**9,541**	**9,706**	**9,865**	**9,857**	**9,976**	**10,429**	**10,837**
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources								261	493	735	1,438	1,953
&	Summer Purch $6/Year							63					
R	**Total Resources**	**10,250**	**10,741**	**10,804**	**10,808**	**10,817**	**10,808**	**10,871**	**11,048**	**11,040**	**11,173**	**11,681**	**12,137**
	Reserves	1,229	1,593	1,556	1,465	1,269	1,267	1,165	1,184	1,183	1,197	1,252	1,301
	Reserve Margin (RM) (%)	13.6	17.4	16.8	15.7	13.3	13.3	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - High Gas
with Medium Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	26.4	27.0	27.8	28.3	28.1	28.5	55.6	82.3	75.7	92.7	512.6
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2								118.1	85.9	257.6	433.8		895.4
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	18.4	21.8	26.4	27.0	27.8	28.3	28.1	306.6	301.5	339.9	509.5	92.7	1728.0
	DSM Programs	15.7	16.9	17.7	21.2	21.4	21.2	21.1	21.0	41.5	62.6	59.2	73.9	393.4
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2													0.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower													0.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											295.4	104.6	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												146.8	146.8
	Total	15.7	16.9	17.7	21.2	21.4	21.2	21.1	21.0	41.5	62.6	354.6	325.3	940.2
	DSM Programs	4.6	4.7	5.5	5.5	5.6	5.6	5.6	5.6	11.4	17.6	17.1	22.0	110.8
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												264.0	264.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.6	4.7	5.5	5.5	5.6	5.6	5.6	5.6	11.4	17.6	17.1	286.0	374.8
	DSM Programs	38.7	43.4	49.6	53.7	54.8	55.1	54.8	55.1	108.5	162.5	152.0	188.6	1016.8
T	Renewable													0.0
O	Cogeneration								278.1	245.9	257.6	433.8		1215.4
T	Combined Cycle CT													0.0
A	Coal & IGCC											295.4	368.6	664.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												146.8	146.8
	Total	38.7	43.4	49.6	53.7	54.8	55.1	54.8	333.2	354.4	420.1	881.2	704.0	3043.0

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(82)	(132)	(185)	(240)	(295)	(350)	(405)	(514)	(676)	(828)	(1,017)
T	**Total Requirements**	8,993	9,012	9,067	9,072	9,158	9,297	9,441	9,602	9,585	9,793	10,128	10,505
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								278	524	782	1,511	2,026
&	Summer Purch $6/Year												
R	**Total Resources**	10,348	10,850	11,020	11,041	11,026	11,018	11,020	11,294	11,004	11,098	11,673	12,164
	Reserves	1,355	1,838	1,953	1,969	1,868	1,721	1,579	1,692	1,419	1,305	1,545	1,659
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.7	20.4	18.5	16.7	17.6	14.8	13.3	15.2	15.8

Med Load - High Gas with Medium Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	31.8	44.5	57.5	70.6	83.8	97.0	122.8	161.4	197.7	242.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2								109.9	189.9	413.0	726.9	716.3
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	9.3	19.3	31.8	44.5	57.5	70.6	83.8	355.8	610.5	872.2	1,222.5	1,256.9
	DSM Programs	9.8	20.2	30.9	43.8	56.9	69.9	82.8	95.7	121.3	160.3	197.8	245.0
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2												
T	Utah Combined Cycle												
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4											270.7	366.6
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												21.8
	Total	9.8	20.2	30.9	43.8	56.9	69.9	82.8	95.7	121.3	160.3	468.5	633.3
	DSM Programs	3.9	7.9	12.6	17.3	22.0	26.8	31.5	36.3	45.7	60.3	74.4	92.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												241.9
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	3.9	7.9	12.6	17.3	22.0	26.8	31.5	36.3	45.7	60.3	74.4	334.3
	DSM Programs	23.0	47.5	75.3	105.6	136.4	167.2	198.1	229.0	289.9	381.9	469.9	580.0
T	Renewable												
O	Cogeneration								258.8	487.7	710.8	1,024.8	1,014.2
T	Combined Cycle CT												
A	Coal & IGCC											270.7	608.5
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												21.8
	Total	23.0	47.5	75.3	105.6	136.4	167.2	198.1	487.8	777.6	1,092.7	1,765.4	2,224.5
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	333.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	499.8	756.0	792.5	769.8	719.9	691.5	610.4	767.2	886.2	871.4	1,013.2	1,144.0
E	**DSM Programs**	(23.0)	(47.5)	(75.3)	(105.6)	(136.4)	(167.2)	(198.0)	(229.0)	(289.9)	(381.9)	(469.9)	(580.0)
M	**Total Requirements**	7,807.4	8,058.3	8,083.5	8,100.1	8,153.1	8,191.2	8,221.9	8,468.3	8,629.4	8,819.4	9,236.0	9,557.5
	Existing Generation	7,161.0	7,515.6	7,574.6	7,601.3	7,654.1	7,690.6	7,715.1	7,715.5	7,715.0	7,688.0	7,545.3	7,528.5
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	89.4	39.0	36.0	34.2	44.8	55.1	64.5	54.9	27.1	38.8	16.7	26.1
R	**New Resources**								258.8	487.7	710.8	1,295.5	1,644.4
	Total Resources	7,807.4	8,058.3	8,083.5	8,100.2	8,153.1	8,191.2	8,221.9	8,468.3	8,629.4	8,819.3	9,236.0	9,557.5

Med Load - High Gas
with Medium Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	47	75	105	136	167	197	228	290	383	471	587
			After Conservation												
			System Load (MWa)	5,701	5,680	5,719	5,800	5,922	6,013	6,125	6,250	6,482	6,859	7,190	7,555
	0.49		Energy Sales (MWa)	5,152	5,159	5,216	5,302	5,400	5,500	5,604	5,709	5,868	6,095	6,405	6,538
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,284	8,481	8,694	8,886	9,233	9,655	9,999	10,627	11,819	13,731	16,105
			Net Conservation Assets ($M)	51	103	166	213	257	300	340	379	449	532	581	651
			Utility Cost												
43,052	3.29	Nominal	**Operating Revenues ($M)**	2,211	2,197	2,235	2,325	2,422	2,545	2,635	2,727	3,013	3,460	3,941	4,565
	-0.01	Real		2,211	2,127	2,094	2,110	2,127	2,163	2,168	2,172	2,250	2,344	2,421	2,463
	2.78	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.1	51.2	52.8	53.7	54.5	58.6	64.8	70.2	79.7
	-0.50	Real		49.0	47.1	45.8	45.4	45.0	44.9	44.2	43.4	43.8	43.9	43.2	43.0
		Nominal	Average Customer Bill ($)	1,667	1,640	1,647	1,685	1,724	1,782	1,815	1,847	1,976	2,164	2,363	2,667
		Real		1,667	1,588	1,543	1,529	1,514	1,515	1,494	1,472	1,476	1,466	1,452	1,439
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	3.0	7.0	10.8	14.3	17.5	20.5	24.0	25.0	22.3	9.7
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.3	2.5	4.0	5.9	8.0	13.0	21.0	28.5	35.0
			Energy Svc Charge ($M)	4.5	9.3	15.6	20.0	24.6	29.3	34.1	39.2	49.6	66.5	80.1	86.9
43,705	3.29	Nominal	**Total Resource Cost ($M)**	2,216	2,207	2,251	2,347	2,449	2,578	2,675	2,774	3,076	3,548	4,049	4,687
	-0.01	Real		2,216	2,136	2,109	2,129	2,151	2,192	2,201	2,210	2,296	2,403	2,488	2,529
	2.61	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.6	50.6	52.1	52.8	53.5	57.2	62.8	67.6	75.6
	-0.67	Real		48.9	46.9	45.6	45.0	44.5	44.3	43.4	42.6	42.7	42.6	41.6	40.8

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.44

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.75

Med Load - High Gas
with Medium Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,948	49,754	50,097	50,780	51,847	52,646	53,626	54,719	56,745	60,050	66,445	66,000
	MWa	5,702	5,680	5,719	5,797	5,919	6,010	6,122	6,246	6,478	6,855	7,585	7,534
	Total Annual Emissions (1000 Tons)												
0.25%	CO2	51,937	51,936	52,083	52,523	53,223	53,649	54,142	54,637	55,612	57,418	60,401	54,413
0.24%	NOx	121.1	121.5	121.9	122.4	123.2	123.5	126.6	126.7	127.0	127.4	132.6	126.9
0.41%	TSP	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.5	11.7
	Annual System Emission Rates (Pounds/MWh)												
-1.21%	CO2	2,080	2,088	2,079	2,069	2,053	2,038	2,019	1,997	1,960	1,912	1,818	1,649
-1.22%	NOx	4.85	4.88	4.87	4.82	4.75	4.69	4.72	4.63	4.48	4.24	3.99	3.84
-1.06%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.42	0.41	0.40	0.38	0.35	0.36
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.39	99.99	99.47	98.72	98.00	97.10	96.03	94.25	91.96	87.42	79.29
	NOx	100	100.71	100.34	99.35	97.96	96.71	97.33	95.47	92.27	87.48	82.26	79.25
	TSP	100	100.54	100.24	99.36	97.94	96.85	95.45	93.75	90.80	86.46	79.32	81.73

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,508	1,110,167
NOx	126.5	2,531
TSP	11.3	225

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Case # 41

Med Load - Med Gas
with Resource Lumpiness

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	16.4	16.9	17.1	17.0	17.1	33.4	49.7	46.0	56.4	316.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2										329.0	441.8	376.0	1146.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	14.3	15.7	16.1	16.4	16.9	17.1	17.0	167.5	183.8	378.7	487.8	432.4	1763.7
	DSM Programs	13.4	13.9	14.6	14.7	14.8	14.8	14.7	14.7	29.0	44.0	41.7	51.8	282.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											206.8	179.4	386.2
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							76.4	91.4	129.5				297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	13.4	13.9	14.6	14.7	14.8	14.8	91.1	106.1	158.5	44.0	248.5	231.2	965.6
	DSM Programs	5.1	5.1	5.8	6.0	6.1	6.0	6.1	6.0	12.0	18.1	17.3	21.5	115.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	5.1	5.1	5.8	6.0	6.1	6.0	6.1	6.0	12.0	18.1	17.3	21.5	115.1
	DSM Programs	32.8	34.7	36.5	37.1	37.8	37.9	37.8	37.8	74.4	111.8	105.0	129.7	713.3
T	Renewable													0.0
O	Cogeneration								150.4	150.4	329.0	648.6	555.4	1833.8
T	Combined Cycle CT							76.4	91.4	129.5				297.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	32.8	34.7	36.5	37.1	37.8	37.9	114.2	279.6	354.3	440.8	753.6	685.1	2844.4

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(68)	(104)	(141)	(179)	(217)	(255)	(292)	(367)	(479)	(584)	(713)
T	**Total Requirements**	9,021	9,149	9,253	9,357	9,571	9,573	9,747	9,916	9,925	10,071	10,552	10,996
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,207	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							76	318	598	927	1,576	2,131
&	Summer Purch $6/Year							33					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,917	11,105	11,145	11,365	11,819	12,315
	Reserves	1,229	1,593	1,551	1,451	1,246	1,235	1,169	1,189	1,220	1,294	1,266	1,319
	Reserve Margin (RM) (%)	13.6	17.4	16.8	15.5	13.0	12.9	12.0	12.0	12.3	12.8	12.0	12.0

Med Load - Med Gas
with Resource Lumpiness

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	23.5	24.4	24.8	24.7	25.0	48.8	71.9	65.3	79.0	450.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2										350.0	470.0	400.0	1220.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	18.4	21.8	22.9	23.5	24.4	24.8	24.7	185.0	208.8	421.9	535.3	479.0	1990.5
	DSM Programs	15.7	16.6	17.7	17.8	18.0	17.9	17.6	17.6	34.7	52.3	48.7	60.0	334.6
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											220.0	190.9	410.9
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							85.1	101.8	144.3				331.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	15.7	16.6	17.7	17.8	18.0	17.9	102.7	119.4	179.0	52.3	268.7	250.9	1076.7
	DSM Programs	4.6	4.7	5.1	5.2	5.4	5.3	5.4	5.3	10.6	16.0	15.0	18.6	101.2
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.6	4.7	5.1	5.2	5.4	5.3	5.4	5.3	10.6	16.0	15.0	18.6	101.2
	DSM Programs	38.7	43.1	45.7	46.5	47.8	48.0	47.7	47.9	94.1	140.2	129.0	157.6	886.3
T	Renewable													0.0
O	Cogeneration								160.0	160.0	350.0	690.0	590.9	1950.9
T	Combined Cycle CT							85.1	101.8	144.3				331.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	38.7	43.1	45.7	46.5	47.8	48.0	132.8	309.7	398.4	490.2	819.0	748.5	3168.4

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(82)	(128)	(174)	(222)	(270)	(318)	(365)	(460)	(600)	(729)	(886)
T	Total Requirements	8,993	9,012	9,072	9,083	9,176	9,322	9,474	9,642	9,640	9,869	10,227	10,636
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,250	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							85	347	651	1,001	1,691	2,282
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,850	11,020	11,041	11,026	11,018	11,105	11,363	11,131	11,317	11,853	12,420
	Reserves	1,355	1,838	1,949	1,958	1,850	1,696	1,631	1,721	1,492	1,448	1,626	1,784
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.6	20.2	18.2	17.2	17.9	15.5	14.7	15.9	16.8

Med Load - Med Gas
with Resource Lumpiness

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	40.4	51.3	62.4	73.5	84.6	106.4	138.8	168.9	205.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2										325.7	743.0	1,035.1
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	9.3	19.3	29.7	40.4	51.3	62.4	73.5	233.5	404.3	762.3	1,209.8	1,538.8
	DSM Programs	9.8	19.9	30.6	41.3	52.2	63.0	73.7	84.5	105.8	138.1	168.9	207.2
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											200.3	360.5
T	Utah Combined Cycle												
A	Utah Gadsby Repower							60.8	131.9	231.8	245.7	213.0	155.3
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	9.8	19.9	30.6	41.3	52.2	63.0	134.5	216.4	337.5	383.8	582.2	723.1
	DSM Programs	3.9	7.9	12.2	16.7	21.2	25.7	30.3	34.8	43.7	57.2	70.3	86.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	3.9	7.9	12.2	16.7	21.2	25.7	30.3	34.8	43.7	57.2	70.3	86.4
	DSM Programs	23.0	47.1	72.6	98.4	124.7	151.1	177.4	203.9	255.8	334.1	408.0	499.5
T	Renewable												
O	Cogeneration								148.9	297.9	623.5	1,241.2	1,693.5
T	Combined Cycle CT							60.8	131.9	231.8	245.7	213.0	155.3
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	23.0	47.1	72.6	98.4	124.7	151.1	238.2	484.7	785.5	1,203.3	1,862.2	2,348.3
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	309.7	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	504.0	763.7	795.1	765.1	704.4	684.9	668.1	775.2	939.3	998.1	1,143.7	1,244.2
E	**DSM Programs**	(23.0)	(47.1)	(72.5)	(98.4)	(124.7)	(151.1)	(177.4)	(203.9)	(255.8)	(334.1)	(408.0)	(499.5)
M	**Total Requirements**	7,811.6	8,065.8	8,088.7	8,102.7	8,149.2	8,200.7	8,300.2	8,501.4	8,716.6	8,993.9	9,428.4	9,710.3
	Existing Generation	7,161.0	7,515.2	7,575.6	7,601.7	7,656.1	7,693.4	7,733.0	7,745.5	7,782.6	7,741.7	7,595.6	7,503.0
L	Firm Purchases	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	Non-Firm Purchases	93.6	46.9	40.2	36.4	39.0	61.8	64.3	35.9	4.8	1.1		
R	New Resources							60.8	280.9	529.6	869.3	1,454.2	1,848.7
	Total Resources	7,811.6	8,065.8	8,088.7	8,102.7	8,149.2	8,200.7	8,300.3	8,501.4	8,716.6	8,993.9	9,428.4	9,710.3

Med Load - Med Gas
with Resource Lumpiness

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	47	72	98	124	151	177	203	256	335	408	505
			After Conservation												
			System Load (MWa)	5,701	5,680	5,722	5,807	5,934	6,030	6,146	6,275	6,516	6,907	7,252	7,637
	0.52		Energy Sales (MWa)	5,152	5,159	5,219	5,309	5,410	5,515	5,623	5,731	5,898	6,138	6,462	6,612
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,284	8,472	8,679	8,903	9,294	9,704	10,076	10,709	11,732	13,262	15,149
			Net Conservation Assets ($M)	51	103	157	193	228	261	291	320	372	427	454	501
			Utility Cost												
42,312	3.26	Nominal	**Operating Revenues ($M)**	2,211	2,197	2,236	2,327	2,424	2,547	2,610	2,684	2,914	3,347	3,865	4,491
	-0.04	Real		2,211	2,127	2,095	2,111	2,129	2,165	2,148	2,138	2,176	2,267	2,375	2,424
	2.73	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.0	51.1	52.7	53.0	53.5	56.4	62.2	68.3	77.5
	-0.55	Real		49.0	47.1	45.8	45.4	44.9	44.8	43.6	42.6	42.1	42.2	42.0	41.8
		Nominal	Average Customer Bill ($)	1,667	1,640	1,647	1,686	1,725	1,783	1,798	1,818	1,912	2,093	2,318	2,624
		Real		1,667	1,588	1,544	1,530	1,515	1,516	1,480	1,448	1,427	1,418	1,424	1,416
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.7	5.4	7.8	9.9	11.7	13.0	13.7	9.3	-0.4	-24.2
			Levelized (20-year at 8.6%)	0.1	0.3	0.5	1.1	2.0	3.0	4.3	5.6	8.6	12.2	13.3	13.3
			Energy Svc Charge ($M)	4.5	9.2	14.4	17.7	21.1	24.6	28.1	31.8	39.5	51.9	60.6	63.4
42,773	3.26	Nominal	**Total Resource Cost ($M)**	2,216	2,207	2,251	2,346	2,447	2,574	2,642	2,721	2,962	3,411	3,939	4,568
	-0.04	Real		2,216	2,136	2,109	2,128	2,149	2,189	2,175	2,168	2,212	2,310	2,420	2,465
	2.58	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.6	50.6	52.0	52.1	52.5	55.1	60.4	65.8	73.7
	-0.69	Real		48.9	46.9	45.6	45.0	44.4	44.2	42.9	41.8	41.2	40.9	40.4	39.8

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.38

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 40.86

Med Load - Med Gas
with Resource Lumpiness

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,948	49,753	50,120	50,843	51,949	52,787	53,806	54,938	57,043	60,469	66,906	66,618
	MWa	5,702	5,680	5,721	5,804	5,930	6,026	6,142	6,271	6,512	6,903	7,638	7,605
	Total Annual Emissions (1000 Tons)												
0.13%	CO2	51,936	51,937	52,095	52,554	53,276	53,721	54,157	54,590	55,503	57,340	59,072	53,240
0.21%	NOx	121.1	121.5	121.9	122.4	123.2	123.5	126.3	126.1	125.9	126.3	126.6	126.0
0.25%	TSP	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.38%	CO2	2,080	2,088	2,079	2,067	2,051	2,035	2,013	1,987	1,946	1,896	1,766	1,598
-1.30%	NOx	4.85	4.88	4.86	4.81	4.74	4.68	4.69	4.59	4.42	4.18	3.78	3.78
-1.26%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.39	99.96	99.41	98.63	97.87	96.80	95.56	93.57	91.19	84.91	76.86
	NOx	100	100.71	100.29	99.24	97.79	96.48	96.79	94.63	91.04	86.11	77.99	77.96
	TSP	100	100.55	100.19	99.25	97.78	96.64	95.09	93.30	90.21	85.70	77.81	78.65

20 Year Emissions (1000 Tons)

	Average	Total
CO2	55,109	1,102,187
NOx	125.0	2,501
TSP	11.2	224

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Med Load - Med Gas
with 25% Lower Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	12.9	15.4	15.8	16.2	16.6	16.8	16.7	16.8	32.9	48.8	45.2	55.6	309.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	125.0	25.4			300.8
C	OWC Cogen 2											720.3	409.6	1129.9
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**12.9**	**15.4**	**15.8**	**16.2**	**16.6**	**16.8**	**16.7**	**167.2**	**157.9**	**74.2**	**765.5**	**465.2**	**1740.4**
	DSM Programs	12.1	12.6	13.0	14.3	14.5	14.5	14.3	14.4	28.4	43.1	40.7	50.9	272.8
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2								18.6		251.7	17.9	106.6	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								168.0	129.3				297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												44.4	44.4
	Total	12.1	12.6	13.0	14.3	14.5	14.5	14.3	201.0	157.7	294.8	58.6	201.9	1009.3
	DSM Programs	3.7	4.6	4.6	4.6	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.8	98.8
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	3.7	4.6	4.6	4.6	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.8	98.8
	DSM Programs	28.7	32.6	33.4	35.1	36.4	36.6	36.3	36.5	71.7	107.8	100.9	125.3	681.3
T	Renewable													0.0
O	Cogeneration								169.0	125.0	277.1	738.2	516.2	1825.5
T	Combined Cycle CT								168.0	129.3				297.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												44.4	44.4
	Total	28.7	32.6	33.4	35.1	36.4	36.6	36.3	373.5	326.0	384.9	839.1	685.9	2848.5

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(29)	(61)	(95)	(130)	(166)	(203)	(239)	(276)	(347)	(455)	(556)	(681)
T	**Total Requirements**	9,025	9,155	9,262	9,368	9,584	9,587	9,763	9,932	9,945	10,095	10,580	11,028
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources								337	591	868	1,607	2,167
&	Summer Purch $6/Year							127					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,935	11,124	11,138	11,306	11,850	12,351
	Reserves	1,225	1,586	1,542	1,440	1,233	1,221	1,172	1,191	1,194	1,212	1,270	1,324
	Reserve Margin (RM) (%)	13.6	17.3	16.6	15.4	12.9	12.7	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with 25% Lower Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.3	21.2	22.3	22.9	23.6	24.0	23.9	24.2	47.1	69.2	62.9	76.3	433.9
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	133.0	27.0			320.0
C	OWC Cogen 2											766.3	435.7	1202.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	16.3	21.2	22.3	22.9	23.6	24.0	23.9	184.2	180.1	96.2	829.2	512.0	1955.9
	DSM Programs	14.4	15.2	16.1	17.6	17.6	17.5	17.4	17.3	34.0	51.4	47.7	59.0	325.2
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2								19.7		267.9	18.9	113.5	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								187.2	144.0				331.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												44.4	44.4
	Total	14.4	15.2	16.1	17.6	17.6	17.5	17.4	224.2	178.0	319.3	66.6	216.9	1120.8
	DSM Programs	3.3	4.1	4.1	4.2	4.9	4.9	4.9	4.9	9.7	14.6	13.7	17.0	90.3
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	3.3	4.1	4.1	4.2	4.9	4.9	4.9	4.9	9.7	14.6	13.7	17.0	90.3
	DSM Programs	34.0	40.5	42.5	44.7	46.1	46.4	46.2	46.4	90.8	135.2	124.3	152.3	849.4
T	Renewable													0.0
O	Cogeneration								179.7	133.0	294.9	785.2	549.2	1942.0
T	Combined Cycle CT								187.2	144.0				331.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												44.4	44.4
	Total	34.0	40.5	42.5	44.7	46.1	46.4	46.2	413.3	367.8	430.1	909.5	745.9	3167.0

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(34)	(75)	(117)	(162)	(208)	(254)	(300)	(347)	(438)	(573)	(697)	(849)
T	Total Requirements	8,998	9,020	9,082	9,095	9,190	9,338	9,491	9,660	9,661	9,896	10,259	10,673
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								367	644	939	1,724	2,318
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,850	11,020	11,041	11,026	11,018	11,020	11,383	11,124	11,255	11,886	12,456
	Reserves	1,350	1,831	1,938	1,946	1,836	1,680	1,529	1,723	1,463	1,359	1,627	1,783
	Reserve Margin (RM) (%)	15.0	20.3	21.3	21.4	20.0	18.0	16.1	17.8	15.1	13.7	15.9	16.7

Med Load - Med Gas
with 25% Lower Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	8.0	17.7	27.8	38.1	48.6	59.3	69.9	80.6	101.6	132.6	161.4	196.9
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	272.7	297.9	297.9	297.9
C	OWC Cogen 2											613.1	961.6
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	8.0	17.7	27.8	38.1	48.6	59.3	69.9	229.6	374.3	430.5	1,072.4	1,456.4
	DSM Programs	8.5	17.3	26.4	36.8	47.3	57.8	68.3	78.7	99.4	130.7	160.6	198.0
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2								15.9	15.8	230.1	245.2	336.0
T	Utah Combined Cycle												
A	Utah Gadsby Repower								64.1	113.4	113.4	113.4	113.4
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												0.1
	Total	8.5	17.3	26.4	36.8	47.3	57.8	68.3	158.7	228.6	474.2	519.2	647.5
	DSM Programs	2.6	6.0	9.4	12.9	17.0	21.1	25.2	29.3	37.4	49.7	61.4	76.2
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	2.6	6.0	9.4	12.9	17.0	21.1	25.2	29.3	37.4	49.7	61.4	76.2
	DSM Programs	19.1	41.0	63.6	87.7	112.9	138.2	163.4	188.6	238.3	313.0	383.5	471.1
T	Renewable												
O	Cogeneration								164.8	288.5	527.9	1,156.2	1,595.5
T	Combined Cycle CT								64.1	113.4	113.4	113.4	113.4
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												0.1
	Total	19.1	41.0	63.6	87.7	112.9	138.2	163.4	417.6	640.2	954.3	1,653.0	2,180.1
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.2
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	497.3	467.1	473.7	464.8	458.1	444.7	476.1	541.4	645.1	616.4	794.9	1,078.7
E	**DSM Programs**	(19.1)	(41.0)	(63.6)	(87.7)	(112.9)	(138.2)	(163.4)	(188.6)	(238.3)	(313.0)	(383.5)	(471.1)
M	**Total Requirements**	7,808.8	7,775.8	7,776.4	7,813.0	7,914.6	7,973.4	8,122.3	8,282.9	8,440.0	8,633.3	9,104.2	9,573.3
	Existing Generation	7,161.3	7,065.0	7,084.0	7,114.0	7,250.7	7,286.8	7,482.5	7,461.9	7,513.6	7,446.9	7,354.6	7,457.2
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	90.6	207.1	219.5	234.4	209.8	241.1	197.6	152.9	125.0	163.3	101.5	48.6
R	**New Resources**								228.9	401.9	641.3	1,269.5	1,709.0
	Total Resources	7,808.9	7,775.8	7,776.4	7,813.0	7,914.6	7,973.4	8,122.4	8,282.9	8,440.0	8,633.3	9,104.2	9,573.2

Med Load - Med Gas
with 25% Lower Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	19	41	63	87	112	137	163	188	238	313	383	475
			After Conservation												
			System Load (MWa)	5,705	5,686	5,731	5,818	5,946	6,043	6,160	6,291	6,534	6,929	7,278	7,667
	0.53		Energy Sales (MWa)	5,156	5,165	5,227	5,319	5,421	5,527	5,636	5,746	5,915	6,158	6,485	6,640
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,076	8,272	8,454	8,654	8,841	9,232	9,709	10,060	10,665	11,697	13,307	15,172
			Net Conservation Assets ($M)	43	91	138	173	206	238	268	296	345	400	426	470
			Utility Cost												
43,459	3.34	Nominal	**Operating Revenues ($M)**	2,212	2,222	2,262	2,353	2,450	2,571	2,666	2,728	3,010	3,453	3,999	4,660
	0.04	Real		2,212	2,151	2,120	2,135	2,151	2,186	2,194	2,173	2,248	2,339	2,457	2,515
	2.80	Nominal	Cost in mills/kWh	49.0	49.1	49.4	50.5	51.6	53.1	54.0	54.2	58.1	64.0	70.4	80.1
	-0.49	Real		49.0	47.6	46.3	45.8	45.3	45.1	44.4	43.2	43.4	43.4	43.3	43.2
		Nominal	Average Customer Bill ($)	1,668	1,659	1,667	1,706	1,744	1,800	1,836	1,848	1,975	2,159	2,399	2,722
		Real		1,668	1,606	1,562	1,547	1,531	1,530	1,511	1,472	1,474	1,463	1,474	1,469
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.5	5.2	7.5	9.6	11.3	12.5	13.0	8.0	-2.6	-27.6
			Levelized (20-year at 8.6%)	0.1	0.3	0.5	1.1	1.9	2.9	4.1	5.4	8.2	11.4	12.1	12.1
			Energy Svc Charge ($M)	3.7	7.9	12.4	15.4	18.6	22.0	25.4	28.9	36.2	47.9	56.8	60.2
43,885	3.34	Nominal	**Total Resource Cost ($M)**	2,216	2,231	2,275	2,370	2,470	2,596	2,695	2,762	3,055	3,512	4,068	4,732
	0.04	Real		2,216	2,159	2,132	2,150	2,169	2,207	2,218	2,200	2,281	2,379	2,500	2,554
	2.66	Nominal	Cost in mills/kWh	48.9	49.0	49.2	50.1	51.1	52.4	53.2	53.3	56.9	62.2	67.9	76.4
	-0.62	Real		48.9	47.4	46.1	45.5	44.8	44.6	43.8	42.5	42.5	42.1	41.7	41.2

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.39

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.92

Med Load - Med Gas
with 25% Lower Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,983	49,810	50,199	50,936	52,051	52,900	53,930	55,072	57,197	60,654	67,156	66,831
	MWa	5,706	5,686	5,731	5,815	5,942	6,039	6,156	6,287	6,529	6,924	7,666	7,629
	Total Annual Emissions (1000 Tons)												
0.20%	CO2	51,954	49,436	49,486	50,037	51,282	51,831	53,402	53,656	54,828	56,585	58,323	53,932
0.20%	NOx	121.1	112.9	113.0	113.8	116.4	117.1	123.6	122.7	123.4	123.4	123.7	125.8
0.24%	TSP	10.9	10.1	10.1	10.2	10.3	10.4	10.8	10.8	10.9	11.0	11.0	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.32%	CO2	2,079	1,985	1,972	1,965	1,970	1,960	1,980	1,949	1,917	1,866	1,737	1,614
-1.32%	NOx	4.85	4.53	4.50	4.47	4.47	4.43	4.58	4.45	4.31	4.07	3.68	3.76
-1.28%	TSP	0.43	0.41	0.40	0.40	0.40	0.39	0.40	0.39	0.38	0.36	0.33	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	95.48	94.84	94.51	94.78	94.26	95.27	93.73	92.22	89.75	83.55	77.64
	NOx	100	93.55	92.86	92.14	92.26	91.32	94.52	91.90	89.01	83.95	76.00	77.66
	TSP	100	93.32	92.83	92.29	91.18	90.38	92.33	90.14	87.87	83.22	75.49	78.25

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,185	1,083,695
NOx	121.4	2,428
TSP	10.8	216

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Med Load - Med Gas
with 25% Higher Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.2	15.6	16.1	16.4	16.9	17.1	17.0	17.1	33.5	49.6	46.0	56.5	316.0
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1					19.6	119.5	81.0	80.7					300.8
C	OWC Cogen 2									39.4	354.9	444.8	378.4	1217.5
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.2**	**15.6**	**16.1**	**16.4**	**36.5**	**136.6**	**98.0**	**97.8**	**72.9**	**404.5**	**490.8**	**434.9**	**1834.3**
	DSM Programs	11.4	13.8	14.3	14.4	14.5	14.5	14.3	14.4	28.4	43.0	40.8	51.0	274.8
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											213.7	181.1	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower					126.2		13.5	103.1					242.8
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**11.4**	**13.8**	**14.3**	**14.4**	**140.7**	**14.5**	**27.8**	**117.5**	**28.4**	**43.0**	**254.5**	**232.1**	**912.4**
	DSM Programs	4.3	4.5	5.2	5.2	5.3	5.3	5.3	5.3	10.5	15.8	15.1	18.6	100.4
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.3**	**4.5**	**5.2**	**5.2**	**5.3**	**5.3**	**5.3**	**5.3**	**10.5**	**15.8**	**15.1**	**18.6**	**100.4**
	DSM Programs	29.9	33.9	35.6	36.0	36.7	36.9	36.6	36.8	72.4	108.4	101.9	126.1	691.2
T	Renewable													0.0
O	Cogeneration					19.6	119.5	81.0	80.7	39.4	354.9	658.5	559.5	1913.1
T	Combined Cycle CT					126.2		13.5	103.1					242.8
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**29.9**	**33.9**	**35.6**	**36.0**	**182.5**	**156.4**	**131.1**	**220.6**	**111.8**	**463.3**	**760.4**	**685.6**	**2847.1**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(30)	(64)	(99)	(135)	(172)	(209)	(246)	(282)	(355)	(463)	(565)	(691)
T	**Total Requirements**	9,024	9,152	9,258	9,363	9,578	9,581	9,756	9,926	9,937	10,087	10,571	11,018
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,207	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources					146	265	360	544	583	938	1,596	2,156
&	Summer Purch $6/Year												
R	**Total Resources**	10,250	10,741	10,804	10,808	10,963	11,073	11,167	11,331	11,130	11,376	11,839	12,340
	Reserves	1,226	1,589	1,546	1,445	1,385	1,492	1,411	1,405	1,193	1,289	1,268	1,322
	Reserve Margin (RM) (%)	13.6	17.4	16.7	15.4	14.5	15.6	14.5	14.2	12.0	12.8	12.0	12.0

Med Load - Med Gas
with 25% Higher Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.3	21.7	22.9	23.5	24.4	24.8	24.7	25.0	48.8	71.9	65.3	79.1	450.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1					20.8	127.2	86.2	85.8					320.0
C	OWC Cogen 2									42.0	377.4	473.3	402.6	1295.3
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.3**	**21.7**	**22.9**	**23.5**	**45.2**	**152.0**	**110.9**	**110.8**	**90.8**	**449.3**	**538.6**	**481.7**	**2065.7**
	DSM Programs	13.8	16.6	17.4	17.5	17.7	17.5	17.3	17.3	34.1	51.3	47.7	59.1	327.3
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											227.4	192.6	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower					140.6		15.1	114.9	0.0	(0.0)	(0.0)	(0.0)	270.6
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compress Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**16.6**	**17.4**	**17.5**	**158.3**	**17.5**	**32.4**	**132.2**	**34.1**	**51.3**	**275.1**	**251.7**	**1017.9**
	DSM Programs	3.9	4.1	4.8	4.8	4.8	4.9	4.9	4.9	9.7	14.7	13.6	16.9	92.0
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**3.9**	**4.1**	**4.8**	**4.8**	**4.8**	**4.9**	**4.9**	**4.9**	**9.7**	**14.7**	**13.6**	**16.9**	**92.0**
	DSM Programs	36.0	42.4	45.1	45.8	46.9	47.2	46.9	47.2	92.6	137.9	126.6	155.1	869.7
T	Renewable													0.0
O	Cogeneration					20.8	127.2	86.2	85.8	42.0	377.4	700.7	595.2	2035.3
T	Combined Cycle CT					140.6		15.1	114.9	0.0	(0.0)	(0.0)	(0.0)	270.6
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**36.0**	**42.4**	**45.1**	**45.8**	**208.3**	**174.4**	**148.2**	**247.9**	**134.6**	**515.3**	**827.3**	**750.3**	**3175.6**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(36)	(78)	(124)	(169)	(216)	(263)	(310)	(358)	(450)	(588)	(715)	(870)
T	**Total Requirements**	**8,996**	**9,016**	**9,076**	**9,088**	**9,182**	**9,329**	**9,481**	**9,650**	**9,649**	**9,881**	**10,241**	**10,652**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,228	10,244	10,250	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources					161	289	390	591	633	1,010	1,711	2,306
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,188**	**11,306**	**11,409**	**11,607**	**11,113**	**11,326**	**11,873**	**12,444**
	Reserves	1,352	1,834	1,945	1,953	2,006	1,978	1,929	1,957	1,464	1,445	1,631	1,792
	Reserve Margin (RM) (%)	15.0	20.4	21.4	21.5	21.8	21.2	20.3	20.3	15.2	14.6	15.9	16.8

Med Load - Med Gas
with 25% Higher Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.1	19.2	29.6	40.2	51.1	62.2	73.3	84.4	106.2	138.6	168.7	205.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1					19.4	137.8	218.0	297.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2									39.0	388.7	806.1	1,085.3
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.1**	**19.2**	**29.6**	**40.2**	**70.5**	**200.0**	**291.3**	**382.3**	**443.1**	**825.2**	**1,272.7**	**1,588.9**
	DSM Programs	8.1	18.2	28.6	39.0	49.6	60.1	70.5	81.0	101.6	133.0	162.8	200.3
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											206.8	367.1
T	Utah Combined Cycle												
A	Utah Gadsby Repower					112.4	112.3	116.0	190.3	210.2	217.1	179.6	124.9
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**8.1**	**18.2**	**28.6**	**39.0**	**162.0**	**172.4**	**186.5**	**271.2**	**311.8**	**350.1**	**549.2**	**692.2**
	DSM Programs	3.3	6.6	10.7	14.7	18.8	22.9	27.0	31.1	39.2	51.5	63.3	77.9
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**6.6**	**10.7**	**14.7**	**18.8**	**22.9**	**27.0**	**31.1**	**39.2**	**51.5**	**63.3**	**77.9**
	DSM Programs	20.5	44.0	68.8	93.9	119.5	145.2	170.8	196.5	247.0	323.1	394.8	483.9
T	Renewable												
O	Cogeneration					19.4	137.8	218.0	297.9	336.9	686.6	1,310.8	1,750.3
T	Combined Cycle CT					112.4	112.3	116.0	190.3	210.2	217.1	179.6	124.9
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**20.5**	**44.0**	**68.8**	**93.9**	**251.3**	**395.3**	**504.8**	**684.6**	**794.1**	**1,226.7**	**1,885.2**	**2,359.0**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	306.8	306.5	306.6	306.8	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	497.2	783.5	885.6	835.5	862.8	920.6	917.9	988.6	990.5	1,068.7	1,167.8	1,245.2
E	**DSM Programs**	(20.5)	(44.0)	(68.8)	(93.9)	(119.5)	(145.2)	(170.8)	(196.5)	(247.0)	(323.1)	(394.8)	(483.9)
M	**Total Requirements**	7,807.3	8,089.2	8,183.0	8,177.6	8,312.6	8,441.9	8,556.3	8,722.1	8,776.6	9,075.6	9,465.7	9,726.9
	Existing Generation	7,161.2	7,564.9	7,679.1	7,690.7	7,719.7	7,739.9	7,776.0	7,794.8	7,830.0	7,788.2	7,596.8	7,493.2
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	89.1	20.6	31.1	22.2	7.1	6.4	4.1			2.0		
R	**New Resources**					131.8	250.1	334.0	488.1	547.1	903.7	1,490.3	1,875.1
	Total Resources	7,807.3	8,089.2	8,183.0	8,177.6	8,312.6	8,441.9	8,556.3	8,722.1	8,776.6	9,075.6	9,465.7	9,726.9

Med Load - Med Gas
with 25% Higher Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	20	44	68	93	119	145	170	196	247	324	395	489
			After Conservation												
			System Load (MWa)	5,704	5,683	5,726	5,812	5,939	6,036	6,153	6,283	6,525	6,918	7,266	7,653
	0.52		Energy Sales (MWa)	5,155	5,162	5,222	5,313	5,415	5,520	5,629	5,738	5,907	6,149	6,474	6,627
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,079	8,286	8,560	8,945	9,284	9,652	9,973	10,161	10,565	11,627	13,176	15,073
			Net Conservation Assets ($M)	46	97	149	185	218	250	281	309	359	414	440	485
			Utility Cost												
41,564	3.21	Nominal	**Operating Revenues ($M)**	2,212	2,168	2,205	2,296	2,349	2,489	2,592	2,668	2,910	3,275	3,782	4,389
	-0.08	Real		2,212	2,098	2,067	2,083	2,063	2,116	2,133	2,126	2,173	2,218	2,324	2,368
	2.68	Nominal	Cost in mills/kWh	49.0	47.9	48.2	49.3	49.5	51.5	52.6	53.1	56.2	60.8	66.7	75.6
	-0.60	Real		49.0	46.4	45.2	44.8	43.5	43.8	43.3	42.3	42.0	41.2	41.0	40.8
		Nominal	Average Customer Bill ($)	1,668	1,618	1,625	1,664	1,672	1,743	1,785	1,807	1,909	2,048	2,268	2,564
		Real		1,668	1,567	1,523	1,510	1,468	1,482	1,469	1,440	1,425	1,387	1,394	1,383
			Total Resource Cost												
			DSR Customer Cost ($M)	0.5	1.5	2.3	5.0	7.3	9.2	10.8	12.0	12.4	7.3	-3.1	-28.1
			Levelized (20-year at 8.6%)	0.1	0.2	0.5	1.0	1.8	2.7	3.9	5.2	7.8	10.9	11.4	11.4
			Energy Svc Charge ($M)	3.9	8.5	13.5	16.6	19.8	23.2	26.6	30.2	37.5	49.3	58.0	60.6
41,998	3.21	Nominal	**Total Resource Cost ($M)**	2,216	2,176	2,219	2,314	2,371	2,515	2,623	2,703	2,956	3,335	3,851	4,461
	-0.09	Real		2,216	2,107	2,080	2,099	2,082	2,138	2,158	2,154	2,207	2,259	2,366	2,407
	2.54	Nominal	Cost in mills/kWh	48.9	47.8	47.9	48.9	49.0	50.8	51.8	52.2	55.0	59.1	64.3	72.0
	-0.74	Real		48.9	46.2	44.9	44.4	43.0	43.2	42.6	41.6	41.1	40.0	39.5	38.8

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.57**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.12**

Med Load - Med Gas
with 25% Higher Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,970	49,784	50,153	50,883	51,993	52,835	53,861	55,002	57,120	60,566	67,043	66,752
	MWa	5,704	5,683	5,725	5,809	5,935	6,031	6,149	6,279	6,521	6,914	7,653	7,620
	Total Annual Emissions (1000 Tons)												
0.14%	CO_2	51,948	52,246	52,375	52,788	53,170	53,622	54,203	54,633	55,640	57,473	59,152	53,297
0.21%	NO_x	121.1	122.5	122.7	123.0	122.6	123.0	126.3	126.1	126.4	126.7	126.7	126.0
0.25%	TSP	10.9	11.0	11.0	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.38%	CO_2	2,079	2,099	2,089	2,075	2,045	2,030	2,013	1,987	1,948	1,898	1,765	1,597
-1.31%	NO_x	4.85	4.92	4.89	4.83	4.72	4.66	4.69	4.59	4.43	4.18	3.78	3.78
-1.27%	TSP	0.43	0.44	0.44	0.43	0.42	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO_2	100	100.95	100.45	99.80	98.37	97.63	96.80	95.55	93.70	91.28	84.87	76.80
	NO_x	100	101.52	100.91	99.72	97.30	96.02	96.76	94.57	91.27	86.28	77.96	77.89
	TSP	100	101.53	100.96	99.84	97.54	96.44	95.20	93.38	90.27	85.69	77.67	78.47

20 Year Emissions (1000 Tons)	Average	Total
CO_2	55,205	1,104,093
NO_x	125.3	2,505
TSP	11.2	224

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Med Load - Med Gas - 250 MW Plant in 1999
with 25% Lower Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	12.9	14.5	15.8	16.2	16.6	16.8	16.7	16.9	32.8	48.8	45.2	55.6	308.8
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									61.6	239.2			300.8
C	OWC Cogen 2				235.0							486.3	409.3	1130.6
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**12.9**	**14.5**	**15.8**	**251.2**	**16.6**	**16.8**	**16.7**	**16.9**	**94.4**	**288.0**	**531.5**	**464.9**	**1740.2**
	DSM Programs	10.6	12.5	13.0	14.4	14.5	14.5	14.3	14.4	28.4	43.0	40.8	51.1	271.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2										38.0	251.9	104.9	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								104.7	192.6				297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												46.1	46.1
	Total	**10.6**	**12.5**	**13.0**	**14.4**	**14.5**	**14.5**	**14.3**	**119.1**	**221.0**	**81.0**	**292.7**	**202.1**	**1009.7**
	DSM Programs	3.7	4.6	4.6	4.6	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.8	98.8
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**3.7**	**4.6**	**4.6**	**4.6**	**5.3**	**5.3**	**5.3**	**5.3**	**10.4**	**15.9**	**15.0**	**18.8**	**98.8**
	DSM Programs	27.2	31.6	33.4	35.2	36.4	36.6	36.3	36.6	71.6	107.7	101.0	125.5	679.1
T	Renewable													0.0
O	Cogeneration				235.0					61.6	277.2	738.2	514.2	1826.2
T	Combined Cycle CT								104.7	192.6				297.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												46.1	46.1
	Total	**27.2**	**31.6**	**33.4**	**270.2**	**36.4**	**36.6**	**36.3**	**141.3**	**325.8**	**384.9**	**839.2**	**685.8**	**2848.7**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(27)	(59)	(92)	(127)	(164)	(200)	(237)	(273)	(345)	(453)	(554)	(679)
T	**Total Requirements**	**9,027**	**9,157**	**9,265**	**9,371**	**9,586**	**9,590**	**9,765**	**9,935**	**9,947**	**10,097**	**10,582**	**11,030**
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources				235	235	235	235	340	594	871	1,609	2,170
&	Summer Purch $6/Year												
R	**Total Resources**	**10,250**	**10,741**	**10,804**	**11,043**	**11,052**	**11,043**	**11,043**	**11,126**	**11,141**	**11,309**	**11,852**	**12,354**
	Reserves	1,223	1,584	1,539	1,672	1,466	1,453	1,278	1,192	1,194	1,212	1,270	1,324
	Reserve Margin (RM) (%)	13.5	17.3	16.6	17.8	15.3	15.2	13.1	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas - 250 MW Plant in 1999 with 25% Lower Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.3	20.4	22.3	22.9	23.6	24.0	23.9	24.1	47.1	69.3	62.9	76.3	433.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									65.6	254.4			320.0
C	OWC Cogen 2				250.0							517.3	435.4	1202.7
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**16.3**	**20.4**	**22.3**	**272.9**	**23.6**	**24.0**	**23.9**	**24.1**	**112.7**	**323.7**	**580.2**	**511.7**	**1955.8**
	DSM Programs	12.9	15.2	16.1	17.5	17.7	17.5	17.3	17.4	34.0	51.3	47.8	59.2	323.9
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2										40.4	268.0	111.6	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								116.6	214.6				331.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												46.1	46.1
	Total	**12.9**	**15.2**	**16.1**	**17.5**	**17.7**	**17.5**	**17.3**	**134.0**	**248.6**	**91.7**	**315.8**	**216.9**	**1121.2**
	DSM Programs	3.3	4.1	4.1	4.2	4.9	4.9	4.9	4.9	9.7	14.6	13.7	17.0	90.3
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**3.3**	**4.1**	**4.1**	**4.2**	**4.9**	**4.9**	**4.9**	**4.9**	**9.7**	**14.6**	**13.7**	**17.0**	**90.3**
	DSM Programs	32.5	39.7	42.5	44.6	46.2	46.4	46.1	46.4	90.8	135.2	124.4	152.5	847.3
T	Renewable													0.0
O	Cogeneration				250.0					65.6	294.8	785.3	547.0	1942.7
T	Combined Cycle CT								116.6	214.6				331.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												46.1	46.1
	Total	**32.5**	**39.7**	**42.5**	**294.6**	**46.2**	**46.4**	**46.1**	**163.0**	**371.0**	**430.0**	**909.7**	**745.6**	**3167.3**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(33)	(72)	(115)	(159)	(206)	(252)	(298)	(344)	(435)	(570)	(695)	(847)
T	**Total Requirements**	**9,000**	**9,022**	**9,084**	**9,098**	**9,193**	**9,340**	**9,493**	**9,663**	**9,664**	**9,899**	**10,261**	**10,675**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources				250	250	250	250	367	647	942	1,727	2,320
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,291**	**11,276**	**11,268**	**11,270**	**11,382**	**11,127**	**11,258**	**11,889**	**12,458**
	Reserves	1,349	1,828	1,936	2,193	2,084	1,928	1,777	1,720	1,463	1,359	1,628	1,783
	Reserve Margin (RM) (%)	15.0	20.3	21.3	24.1	22.7	20.6	18.7	17.8	15.1	13.7	15.9	16.7

Med Load - Med Gas - 250 MW Plant in 1999 with 25% Lower Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	8.0	16.9	27.0	37.3	47.8	58.5	69.2	79.9	100.8	131.8	160.7	196.2
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1									61.0	297.9	297.9	297.9
C	OWC Cogen 2				200.0	200.0	200.0	200.0	200.0	200.0	200.0	613.9	962.2
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**8.0**	**16.9**	**27.0**	**237.3**	**247.8**	**258.5**	**269.2**	**279.9**	**361.8**	**629.7**	**1,072.4**	**1,456.2**
	DSM Programs	7.0	15.8	24.9	35.3	45.8	56.3	66.8	77.2	97.9	129.2	159.1	196.8
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2										32.6	246.7	336.0
T	Utah Combined Cycle												
A	Utah Gadsby Repower								40.0	113.4	114.7	113.4	113.4
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												0.1
	Total	**7.0**	**15.8**	**24.9**	**35.3**	**45.8**	**56.3**	**66.8**	**117.2**	**211.2**	**276.5**	**519.2**	**646.3**
	DSM Programs	2.6	6.0	9.4	12.9	17.0	21.1	25.2	29.3	37.4	49.7	61.4	76.2
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**2.6**	**6.0**	**9.4**	**12.9**	**17.0**	**21.1**	**25.2**	**29.3**	**37.4**	**49.7**	**61.4**	**76.2**
	DSM Programs	17.6	38.7	61.3	85.4	110.6	135.9	161.1	186.3	236.0	310.7	381.2	469.1
T	Renewable												
O	Cogeneration				200.0	200.0	200.0	200.0	200.0	261.0	530.5	1,158.4	1,596.1
T	Combined Cycle CT								40.0	113.4	114.7	113.4	113.4
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												0.1
	Total	**17.6**	**38.7**	**61.3**	**285.4**	**310.6**	**335.9**	**361.1**	**426.3**	**610.4**	**955.8**	**1,653.0**	**2,178.7**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.2
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	496.4	460.1	473.1	550.9	600.0	574.4	525.4	541.1	638.1	632.6	801.5	1,077.2
E	**DSM Programs**	(17.6)	(38.7)	(61.3)	(85.4)	(110.6)	(135.9)	(161.1)	(186.3)	(236.0)	(310.7)	(381.2)	(469.1)
M	**Total Requirements**	7,809.4	7,771.1	7,778.0	7,901.4	8,058.8	8,105.5	8,174.0	8,284.8	8,435.2	8,651.8	9,113.0	9,573.9
	Existing Generation	7,161.4	7,065.9	7,084.5	7,035.5	7,239.0	7,289.9	7,428.1	7,459.0	7,513.6	7,447.8	7,354.7	7,457.2
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	91.0	201.5	220.6	201.3	165.8	170.0	103.7	146.7	147.7	177.1	107.9	48.5
R	**New Resources**				200.0	200.0	200.0	200.0	240.0	374.4	645.1	1,271.8	1,709.6
	Total Resources	7,809.4	7,771.1	7,778.0	7,901.4	8,058.8	8,105.5	8,174.0	8,284.8	8,435.2	8,651.8	9,113.0	9,573.8

Med Load - Med Gas - 250 MW Plant in 1999
with 25% Lower Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	17	38	61	85	110	135	160	186	236	311	381	473
			After Conservation												
			System Load (MWa)	5,707	5,689	5,733	5,820	5,948	6,045	6,163	6,293	6,537	6,931	7,280	7,669
	0.53		Energy Sales (MWa)	5,157	5,167	5,229	5,321	5,423	5,529	5,638	5,748	5,917	6,160	6,487	6,642
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,372	8,679	8,873	9,036	9,269	9,538	9,884	10,487	11,640	13,307	15,171
			Net Conservation Assets ($M)	40	86	134	169	203	235	265	293	343	399	426	470
			Utility Cost												
43,512	3.34	Nominal	**Operating Revenues ($M)**	2,212	2,223	2,262	2,362	2,492	2,612	2,693	2,770	2,989	3,431	3,992	4,661
	0.04	Real		2,212	2,152	2,120	2,143	2,189	2,221	2,217	2,207	2,232	2,324	2,453	2,515
	2.80	Nominal	Cost in mills/kWh	49.0	49.1	49.4	50.7	52.5	53.9	54.5	55.0	57.7	63.6	70.3	80.1
	-0.49	Real		49.0	47.5	46.3	46.0	46.1	45.9	44.9	43.8	43.1	43.1	43.2	43.2
		Nominal	Average Customer Bill ($)	1,668	1,659	1,667	1,712	1,774	1,829	1,855	1,877	1,961	2,146	2,394	2,723
		Real		1,668	1,606	1,562	1,553	1,558	1,555	1,527	1,495	1,464	1,453	1,471	1,469
			Total Resource Cost												
			DSR Customer Cost ($M)	0.7	1.6	2.4	5.0	7.4	9.5	11.1	12.3	12.8	7.8	-2.8	-27.8
			Levelized (20-year at 8.6%)	0.1	0.2	0.5	1.0	1.8	2.8	4.0	5.3	8.0	11.2	11.9	11.9
			Energy Svc Charge ($M)	3.4	7.4	11.9	14.9	18.2	21.5	24.9	28.4	35.7	47.4	56.6	60.2
43,932	3.34	Nominal	**Total Resource Cost ($M)**	2,216	2,230	2,275	2,378	2,512	2,637	2,722	2,804	3,033	3,489	4,061	4,733
	0.04	Real		2,216	2,159	2,132	2,157	2,206	2,242	2,240	2,234	2,264	2,363	2,495	2,554
	2.66	Nominal	Cost in mills/kWh	48.9	48.9	49.1	50.3	51.9	53.3	53.7	54.1	56.4	61.8	67.8	76.4
	-0.62	Real		48.9	47.4	46.1	45.6	45.6	45.3	44.2	43.1	42.1	41.9	41.7	41.2

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **43.43**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.97**

Med Load - Med Gas - 250 MW Plant in 1999
with 25% Lower Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,995	49,830	50,219	50,956	52,072	52,921	53,950	55,092	57,217	60,674	67,174	66,831
	MWa	5,707	5,688	5,733	5,817	5,944	6,041	6,159	6,289	6,532	6,926	7,668	7,629
	Total Annual Emissions (1000 Tons)												
0.20%	CO2	51,960	49,451	49,497	49,583	51,222	51,858	53,082	53,678	54,837	56,593	58,332	53,938
0.20%	NOx	121.1	113.0	113.0	112.2	116.2	117.2	122.4	122.8	123.4	123.4	123.7	125.8
0.24%	TSP	10.9	10.1	10.1	10.2	10.3	10.4	10.7	10.8	10.9	11.0	11.0	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.32%	CO2	2,079	1,985	1,971	1,946	1,967	1,960	1,968	1,949	1,917	1,865	1,737	1,614
-1.32%	NOx	4.85	4.53	4.50	4.40	4.46	4.43	4.54	4.46	4.31	4.07	3.68	3.76
-1.28%	TSP	0.43	0.41	0.40	0.40	0.40	0.39	0.40	0.39	0.38	0.36	0.33	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	95.49	94.84	93.63	94.65	94.29	94.67	93.75	92.22	89.75	83.55	77.66
	NOx	100	93.55	92.86	90.85	92.06	91.36	93.67	91.97	89.00	83.95	76.00	77.68
	TSP	100	93.31	92.82	91.97	91.12	90.42	91.29	90.05	87.86	83.21	75.49	78.27

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,153	1,083,050
NOx	121.3	2,425
TSP	10.8	216

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Med Load - Med Gas - 250 MW Plant in 1999 with Medium Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	12.9	15.4	15.8	16.4	16.8	17.1	17.0	17.0	33.5	49.7	46.1	56.7	314.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									128.8	172.0			300.8
C	OWC Cogen 2				235.0						104.2	519.8	381.8	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**12.9**	**15.4**	**15.8**	**251.4**	**16.8**	**17.1**	**17.0**	**17.0**	**162.3**	**325.9**	**565.9**	**438.5**	**1856.0**
	DSM Programs	11.4	12.5	14.3	14.4	14.5	14.5	14.3	14.4	28.4	43.0	40.8	51.0	273.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											217.3	177.5	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								98.6	124.7	(0.0)			223.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**11.4**	**12.5**	**14.3**	**14.4**	**14.5**	**14.5**	**14.3**	**113.0**	**153.1**	**43.0**	**258.1**	**228.5**	**891.6**
	DSM Programs	4.5	4.5	4.6	5.2	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.7	100.0
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.5**	**4.5**	**4.6**	**5.2**	**5.3**	**5.3**	**5.3**	**5.3**	**10.4**	**15.9**	**15.0**	**18.7**	**100.0**
	DSM Programs	28.8	32.4	34.7	36.0	36.6	36.9	36.6	36.7	72.3	108.6	101.9	126.4	687.9
T	Renewable													0.0
O	Cogeneration				235.0					128.8	276.2	737.1	559.3	1936.4
T	Combined Cycle CT								98.6	124.7	(0.0)			223.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**28.8**	**32.4**	**34.7**	**271.0**	**36.6**	**36.9**	**36.6**	**135.3**	**325.8**	**384.8**	**839.0**	**685.7**	**2847.6**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(29)	(61)	(96)	(132)	(169)	(205)	(242)	(279)	(351)	(460)	(562)	(688)
T	**Total Requirements**	**9,025**	**9,155**	**9,261**	**9,366**	**9,582**	**9,585**	**9,760**	**9,929**	**9,941**	**10,090**	**10,575**	**11,021**
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,844
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources				235	235	235	235	334	587	863	1,600	2,160
&	Summer Purch $6/Year												
R	**Total Resources**	**10,250**	**10,741**	**10,804**	**11,043**	**11,052**	**11,043**	**11,043**	**11,121**	**11,134**	**11,301**	**11,843**	**12,344**
	Reserves	1,225	1,586	1,543	1,677	1,471	1,458	1,283	1,191	1,193	1,210	1,268	1,323
	Reserve Margin (RM) (%)	13.6	17.3	16.7	17.9	15.3	15.2	13.1	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas - 250 MW Plant in 1999 with Medium Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.3	21.2	22.3	23.3	24.1	24.5	24.5	24.8	48.8	71.9	65.6	79.7	447.0
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									137.0	183.0			320.0
C	OWC Cogen 2				250.0						110.9	553.0	406.1	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**16.3**	**21.2**	**22.3**	**273.3**	**24.1**	**24.5**	**24.5**	**24.8**	**185.8**	**365.8**	**618.6**	**485.8**	**2087.0**
	DSM Programs	13.8	15.3	17.4	17.5	17.7	17.5	17.3	17.3	34.1	51.3	47.7	59.1	326.0
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											231.2	188.8	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								109.9	138.9	0.0			248.8
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**15.3**	**17.4**	**17.5**	**17.7**	**17.5**	**17.3**	**127.2**	**173.0**	**51.3**	**278.9**	**247.9**	**994.8**
	DSM Programs	4.0	4.1	4.1	4.8	4.9	4.9	4.9	4.9	9.7	14.6	13.7	16.9	91.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.0	4.1	4.1	4.8	4.9	4.9	4.9	4.9	9.7	14.6	13.7	16.9	91.5
	DSM Programs	34.1	40.6	43.8	45.6	46.7	46.9	46.7	47.0	92.6	137.8	127.0	155.7	864.5
T	Renewable													0.0
O	Cogeneration				250.0					137.0	293.9	784.2	594.9	2060.0
T	Combined Cycle CT								109.9	138.9	0.0			248.8
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**34.1**	**40.6**	**43.8**	**295.6**	**46.7**	**46.9**	**46.7**	**156.9**	**368.5**	**431.7**	**911.2**	**750.6**	**3173.3**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(34)	(75)	(119)	(164)	(211)	(258)	(304)	(351)	(444)	(582)	(709)	(865)
T	**Total Requirements**	**8,998**	**9,019**	**9,081**	**9,093**	**9,187**	**9,334**	**9,487**	**9,656**	**9,655**	**9,887**	**10,247**	**10,658**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,162	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources				250	250	250	250	360	636	930	1,714	2,309
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,291**	**11,276**	**11,268**	**11,270**	**11,376**	**11,116**	**11,245**	**11,875**	**12,446**
	Reserves	1,350	1,831	1,940	2,198	2,089	1,934	1,783	1,720	1,461	1,358	1,628	1,789
	Reserve Margin (RM) (%)	15.0	20.3	21.4	24.2	22.7	20.7	18.8	17.8	15.1	13.7	15.9	16.8

Med Load - Med Gas - 250 MW Plant in 1999 with Medium Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	8.0	17.7	27.8	38.3	49.2	60.1	71.1	82.2	104.0	136.3	166.6	203.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1									127.6	297.9	297.9	297.9
C	OWC Cogen 2				228.7	232.6	232.6	232.6	232.6	232.6	335.8	820.5	1,101.0
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**8.0**	**17.7**	27.8	**267.0**	281.8	**292.7**	303.7	**314.8**	**464.1**	**770.0**	**1,284.9**	**1,602.7**
	DSM Programs	8.1	16.9	27.3	37.7	48.3	58.8	69.2	79.7	100.3	131.7	161.5	199.0
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											210.2	367.2
T	Utah Combined Cycle												
A	Utah Gadsby Repower								82.5	183.6	189.7	156.8	114.9
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**8.1**	**16.9**	**27.3**	**37.7**	**48.3**	**58.8**	**69.2**	**162.2**	**283.9**	**321.3**	528.6	**681.0**
	DSM Programs	3.3	6.7	10.1	14.2	18.3	22.4	26.5	30.6	38.7	51.0	62.7	77.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**6.7**	**10.1**	**14.2**	**18.3**	**22.4**	**26.5**	**30.6**	**38.7**	**51.0**	**62.7**	**77.4**
	DSM Programs	19.4	41.3	65.2	90.2	115.7	141.3	166.8	192.4	242.9	319.0	390.9	480.2
T	Renewable												
O	Cogeneration				228.7	232.6	232.6	232.6	232.6	360.2	633.6	1,328.6	1,766.1
T	Combined Cycle CT								82.5	183.6	189.7	156.8	114.9
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**19.4**	**41.3**	65.2	**318.9**	**348.3**	**373.9**	**399.4**	**507.5**	786.7	**1,142.3**	**1,876.3**	**2,361.1**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	306.9	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	496.4	753.3	782.2	923.1	881.5	843.3	776.2	794.6	923.2	946.2	1,145.8	1,244.1
E	**DSM Programs**	(19.4)	(41.3)	(65.2)	(90.2)	(115.7)	(141.3)	(166.8)	(192.4)	(242.9)	(319.0)	(390.9)	(480.2)
M	**Total Requirements**	7,807.6	8,061.6	8,083.3	8,268.9	8,335.3	8,368.9	8,419.1	8,532.2	8,713.4	8,957.1	9,447.7	9,729.5
	Existing Generation	7,161.2	7,516.5	7,578.8	7,566.3	7,635.1	7,663.9	7,696.6	7,737.4	7,768.5	7,739.9	7,583.7	7,490.0
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	89.4	41.4	31.5	9.2	13.5	26.9	47.6	40.6	1.6	12.2		
R	**New Resources**				228.7	232.6	232.6	232.6	315.1	543.8	823.3	1,485.4	1,880.9
	Total Resources	7,807.6	8,061.6	8,083.3	8,268.9	8,335.3	8,368.9	8,419.1	8,532.3	8,713.4	8,957.1	9,447.7	9,729.5

Med Load - Med Gas - 250 MW Plant in 1999
with Medium Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	19	41	65	90	115	141	166	192	244	320	391	486
			After Conservation												
			System Load (MWa)	5,705	5,686	5,730	5,816	5,943	6,039	6,156	6,286	6,529	6,922	7,269	7,657
	0.52		Energy Sales (MWa)	5,156	5,165	5,226	5,316	5,419	5,524	5,632	5,742	5,910	6,152	6,477	6,630
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,087	8,377	8,686	8,882	9,044	9,274	9,542	9,898	10,516	11,613	13,275	15,164
			Net Conservation Assets ($M)	44	91	142	178	212	244	275	303	355	412	440	485
			Utility Cost												
42,598	3.28	Nominal	Operating Revenues ($M)	2,212	2,198	2,237	2,330	2,458	2,577	2,660	2,722	2,921	3,355	3,885	4,529
	-0.02	Real		2,212	2,127	2,096	2,114	2,159	2,191	2,189	2,169	2,181	2,272	2,387	2,444
	2.74	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.0	51.8	53.3	53.9	54.1	56.4	62.3	68.5	78.0
	-0.54	Real		49.0	47.0	45.8	45.4	45.5	45.3	44.4	43.1	42.1	42.2	42.1	42.1
		Nominal	Average Customer Bill ($)	1,668	1,641	1,648	1,689	1,749	1,804	1,832	1,844	1,916	2,098	2,330	2,646
		Real		1,668	1,588	1,544	1,532	1,536	1,534	1,508	1,469	1,431	1,421	1,432	1,428
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.6	4.9	7.1	9.0	10.6	11.8	12.1	7.0	-3.4	-28.4
			Levelized (20-year at 8.6%)	0.1	0.3	0.5	1.1	1.8	2.8	3.9	5.1	7.7	10.7	11.2	11.2
			Energy Svc Charge ($M)	3.7	8.0	12.7	15.9	19.1	22.5	25.9	29.4	36.8	48.6	57.5	60.6
43,025	3.28	Nominal	Total Resource Cost ($M)	2,216	2,206	2,250	2,347	2,479	2,602	2,690	2,757	2,966	3,414	3,954	4,601
	-0.02	Real		2,216	2,135	2,108	2,130	2,177	2,212	2,214	2,197	2,214	2,313	2,430	2,483
	2.60	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.6	51.2	52.6	53.1	53.2	55.2	60.5	66.0	74.2
	-0.68	Real		48.9	46.9	45.5	45.0	45.0	44.7	43.7	42.4	41.2	41.0	40.6	40.1

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.58

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.10

Med Load - Med Gas - 250 MW Plant in 1999
with Medium Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,980	49,807	50,185	50,915	52,028	52,873	53,900	55,039	57,156	60,602	67,075	66,753
	MWa	5,705	5,686	5,729	5,812	5,939	6,036	6,153	6,283	6,525	6,918	7,657	7,620
	Total Annual Emissions (1000 Tons)												
0.14%	CO2	51,952	51,965	52,131	52,444	53,232	53,745	54,258	54,707	55,621	57,474	59,187	53,319
0.21%	NOx	121.1	121.5	121.9	121.9	123.0	123.5	126.6	126.4	126.2	126.6	126.8	126.1
0.25%	TSP	10.9	10.9	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.38%	CO2	2,079	2,087	2,078	2,060	2,046	2,033	2,013	1,988	1,946	1,897	1,765	1,598
-1.30%	NOx	4.85	4.88	4.86	4.79	4.73	4.67	4.70	4.59	4.42	4.18	3.78	3.78
-1.27%	TSP	0.43	0.44	0.44	0.43	0.42	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.37	99.93	99.09	98.43	97.79	96.84	95.62	93.62	91.24	84.89	76.84
	NOx	100	100.68	100.24	98.77	97.50	96.39	96.87	94.74	91.12	86.20	77.99	77.92
	TSP	100	100.52	100.15	98.69	97.45	96.54	95.05	93.27	90.14	85.63	77.68	78.46

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,186	1,103,713
NOx	125.2	2,503
TSP	11.2	224

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Med Load - Med Gas - 250 MW Plant in 1999 with 25% Higher Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.2	15.4	15.9	16.3	16.7	16.8	16.9	16.9	33.1	49.0	45.5	55.7	312.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								136.3		164.5			300.8
C	OWC Cogen 2				235.0						180.4	422.7	402.7	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.2**	**15.4**	**15.9**	**251.3**	**16.7**	**16.8**	**16.9**	**153.2**	**33.1**	**393.9**	**468.2**	**458.4**	**1854.0**
	DSM Programs	11.4	12.7	14.3	14.4	14.5	14.4	14.4	14.4	28.3	43.1	40.8	50.9	273.6
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											237.2	157.6	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower					5.0	46.7	71.3	99.5	3.0				225.5
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**11.4**	**12.7**	**14.3**	**14.4**	**19.5**	**61.1**	**85.7**	**113.9**	**31.3**	**43.1**	**278.0**	**208.5**	**893.9**
	DSM Programs	4.3	4.5	4.6	5.2	5.3	5.3	5.3	5.3	10.5	15.8	15.1	18.6	99.8
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.3**	**4.5**	**4.6**	**5.2**	**5.3**	**5.3**	**5.3**	**5.3**	**10.5**	**15.8**	**15.1**	**18.6**	**99.8**
	DSM Programs	29.9	32.6	34.8	35.9	36.5	36.5	36.6	36.6	71.9	107.9	101.4	125.2	685.8
T	Renewable													0.0
O	Cogeneration				235.0				136.3		344.9	659.9	560.3	1936.4
T	Combined Cycle CT					5.0	46.7	71.3	99.5	3.0				225.5
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**29.9**	**32.6**	**34.8**	**270.9**	**41.5**	**83.2**	**107.9**	**272.4**	**74.9**	**452.8**	**761.3**	**685.5**	**2847.7**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(30)	(63)	(97)	(133)	(170)	(206)	(243)	(279)	(351)	(459)	(561)	(686)
T	Total Requirements	9,024	9,154	9,260	9,365	9,580	9,584	9,759	9,929	9,941	10,091	10,575	11,023
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,207	10,208	10,122	10,013	9,868	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources				235	240	287	358	594	597	942	1,602	2,162
&	Summer Purch $6/Year												
R	Total Resources	10,250	10,741	10,804	11,043	11,057	11,095	11,165	11,381	11,143	11,379	11,844	12,346
	Reserves	1,226	1,588	1,544	1,678	1,477	1,511	1,406	1,452	1,202	1,288	1,268	1,323
	Reserve Margin (RM) (%)	13.6	17.3	16.7	17.9	15.4	15.8	14.4	14.6	12.1	12.8	12.0	12.0

Med Load - Med Gas - 250 MW Plant in 1999 with 25% Higher Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.3	21.5	22.8	23.3	24.2	24.6	24.5	24.8	48.5	71.3	64.8	78.4	447.0
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								145.0		175.0			320.0
C	OWC Cogen 2				250.0						192.0	449.6	428.4	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.3**	**21.5**	**22.8**	**273.3**	**24.2**	**24.6**	**24.5**	**169.8**	**48.5**	**438.3**	**514.4**	**506.8**	**2087.0**
	DSM Programs	13.8	15.4	17.4	17.6	17.6	17.5	17.4	17.3	34.0	51.4	47.7	59.1	326.2
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											252.3	167.7	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower					5.5	52.1	79.5	110.8	3.4				251.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**15.4**	**17.4**	**17.6**	**23.1**	**69.6**	**96.9**	**128.1**	**37.4**	**51.4**	**300.0**	**226.8**	**997.5**
	DSM Programs	3.9	4.1	4.2	4.8	4.8	4.9	4.9	4.9	9.7	14.7	13.6	16.9	91.4
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**3.9**	**4.1**	**4.2**	**4.8**	**4.8**	**4.9**	**4.9**	**4.9**	**9.7**	**14.7**	**13.6**	**16.9**	**91.4**
	DSM Programs	36.0	41.0	44.4	45.7	46.6	47.0	46.8	47.0	92.2	137.4	126.1	154.4	864.6
T	Renewable													0.0
O	Cogeneration				250.0				145.0		367.0	701.9	596.1	2060.0
T	Combined Cycle CT					5.5	52.1	79.5	110.8	3.4				251.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**36.0**	**41.0**	**44.4**	**295.7**	**52.1**	**99.1**	**126.3**	**302.8**	**95.6**	**504.4**	**828.0**	**750.5**	**3175.9**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(36)	(77)	(121)	(167)	(214)	(261)	(308)	(355)	(447)	(584)	(710)	(865)
T	**Total Requirements**	**8,996**	**9,017**	**9,078**	**9,090**	**9,184**	**9,331**	**9,484**	**9,653**	**9,652**	**9,885**	**10,246**	**10,657**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,046	9,892	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources				250	256	308	387	643	646	1,013	1,715	2,311
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,291**	**11,281**	**11,326**	**11,407**	**11,659**	**11,127**	**11,329**	**11,876**	**12,450**
	Reserves	1,352	1,833	1,942	2,201	2,097	1,994	1,924	2,006	1,474	1,444	1,631	1,792
	Reserve Margin (RM) (%)	15.0	20.3	21.4	24.2	22.8	21.4	20.3	20.8	15.3	14.6	15.9	16.8

Med Load - Med Gas - 250 MW Plant in 1999 with 25% Higher Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.1	19.0	29.2	39.7	50.5	61.4	72.3	83.2	104.7	136.6	166.2	202.5
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								134.9	134.9	297.9	297.9	297.9
C	OWC Cogen 2				227.6	232.6	232.6	232.6	232.6	232.6	409.1	805.7	1,100.3
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.1**	**19.0**	**29.2**	**267.3**	**283.1**	**294.0**	**304.9**	**450.8**	**472.2**	**843.5**	**1,269.8**	**1,600.7**
	DSM Programs	8.1	17.1	27.5	37.9	48.4	58.9	69.4	79.8	100.5	131.8	161.7	199.1
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											228.0	367.2
T	Utah Combined Cycle												
A	Utah Gadsby Repower					4.4	46.0	103.8	169.3	194.4	201.7	166.4	116.8
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**8.1**	**17.1**	**27.5**	**37.9**	**52.9**	**104.9**	**173.1**	**249.2**	**294.8**	**333.5**	**556.1**	**683.1**
	DSM Programs	3.3	6.6	10.1	14.1	18.2	22.3	26.4	30.5	38.6	50.9	62.7	77.3
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**6.6**	**10.1**	**14.1**	**18.2**	**22.3**	**26.4**	**30.5**	**38.6**	**50.9**	**62.7**	**77.3**
	DSM Programs	20.5	42.7	66.7	91.7	117.1	142.6	168.0	193.6	243.8	319.3	390.6	479.0
T	Renewable												
O	Cogeneration				227.6	232.6	232.6	232.6	367.6	367.6	706.9	1,331.5	1,765.4
T	Combined Cycle CT					4.4	46.0	103.8	169.3	194.4	201.7	166.4	116.8
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**20.5**	**42.7**	**66.7**	**319.3**	**354.1**	**421.2**	**504.4**	**730.5**	**805.7**	**1,227.9**	**1,888.5**	**2,361.1**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.7	307.2	306.7	307.0	306.5	306.2	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	497.2	785.3	884.3	963.8	940.2	929.2	912.0	1,009.9	994.2	1,064.2	1,166.8	1,245.3
E	**DSM Programs**	(20.5)	(42.7)	(66.7)	(91.7)	(117.1)	(142.6)	(168.0)	(193.6)	(243.8)	(319.3)	(390.6)	(478.9)
M	**Total Requirements**	7,807.3	8,092.3	8,183.7	8,308.0	8,392.4	8,453.5	8,553.2	8,745.7	8,783.6	9,074.9	9,469.0	9,731.9
	Existing Generation	7,161.2	7,565.2	7,679.5	7,615.8	7,701.2	7,729.4	7,774.5	7,769.7	7,822.1	7,782.4	7,592.4	7,491.2
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.9	378.6	358.5
&	**Non-Firm Purchases**	89.1	23.3	31.3							2.0		
R	**New Resources**				227.6	237.1	278.6	336.4	536.9	561.9	908.6	1,498.0	1,882.2
	Total Resources	7,807.3	8,092.3	8,183.7	8,308.1	8,392.4	8,453.5	8,553.2	8,745.7	8,783.6	9,074.9	9,469.0	9,731.9

Med Load - Med Gas - 250 MW Plant in 1999
with 25% Higher Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	20	42	66	91	116	141	167	192	243	318	388	481
			After Conservation												
			System Load (MWa)	5,704	5,685	5,728	5,814	5,942	6,039	6,156	6,287	6,530	6,924	7,272	7,661
	0.53		Energy Sales (MWa)	5,155	5,164	5,224	5,315	5,418	5,523	5,632	5,742	5,911	6,154	6,480	6,634
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,089	8,380	8,695	8,922	9,166	9,538	9,910	10,083	10,473	11,643	13,199	15,088
			Net Conservation Assets ($M)	46	94	145	180	214	245	275	304	354	409	436	480
			Utility Cost												
41,676	3.22	Nominal	**Operating Revenues ($M)**	2,212	2,168	2,206	2,292	2,418	2,521	2,587	2,657	2,912	3,272	3,794	4,400
	-0.08	Real		2,212	2,099	2,067	2,080	2,123	2,143	2,129	2,117	2,174	2,216	2,331	2,374
	2.68	Nominal	Cost in mills/kWh	49.0	47.9	48.2	49.2	50.9	52.1	52.4	52.8	56.3	60.7	66.8	75.7
	-0.60	Real		49.0	46.4	45.2	44.7	44.7	44.3	43.2	42.1	42.0	41.1	41.1	40.9
		Nominal	Average Customer Bill ($)	1,668	1,619	1,625	1,662	1,721	1,765	1,782	1,800	1,910	2,046	2,275	2,570
		Real		1,668	1,567	1,523	1,507	1,511	1,501	1,467	1,434	1,426	1,386	1,398	1,387
			Total Resource Cost												
			DSR Customer Cost ($M)	0.5	1.4	2.2	4.8	7.0	8.9	10.5	11.6	11.8	6.5	-4.1	-29.5
			Levelized (20-year at 8.6%)	0.1	0.2	0.4	1.0	1.7	2.6	3.8	5.0	7.5	10.4	10.8	10.8
			Energy Svc Charge ($M)	3.9	8.2	12.9	16.0	19.2	22.5	25.9	29.4	36.7	48.3	56.8	59.7
42,098	3.21	Nominal	**Total Resource Cost ($M)**	2,216	2,176	2,219	2,309	2,439	2,546	2,617	2,692	2,957	3,330	3,861	4,470
	-0.08	Real		2,216	2,107	2,079	2,095	2,142	2,165	2,153	2,144	2,207	2,256	2,373	2,412
	2.54	Nominal	Cost in mills/kWh	48.9	47.8	47.9	48.8	50.4	51.4	51.6	51.9	55.0	59.0	64.5	72.1
	-0.73	Real		48.9	46.2	44.9	44.3	44.3	43.7	42.5	41.4	41.1	40.0	39.6	38.9

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.64**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.21**

Med Load - Med Gas - 250 MW Plant in 1999
with 25% Higher Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,970	49,795	50,170	50,901	52,013	52,861	53,885	55,022	57,149	60,600	67,086	66,784
	MWa	5,704	5,684	5,727	5,811	5,938	6,034	6,151	6,281	6,524	6,918	7,658	7,624
	Total Annual Emissions (1000 Tons)												
0.14%	CO2	51,948	52,253	52,385	52,538	53,411	53,766	54,227	54,636	55,656	57,500	59,173	53,315
0.21%	NOx	121.1	122.5	122.7	122.2	123.5	123.5	126.4	126.1	126.4	126.7	126.7	126.1
0.25%	TSP	10.9	11.0	11.0	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.38%	CO2	2,079	2,099	2,088	2,064	2,054	2,034	2,013	1,986	1,948	1,898	1,764	1,597
-1.31%	NOx	4.85	4.92	4.89	4.80	4.75	4.67	4.69	4.58	4.42	4.18	3.78	3.78
-1.27%	TSP	0.43	0.44	0.44	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.94	100.44	99.29	98.78	97.84	96.80	95.52	93.68	91.27	84.85	76.79
	NOx	100	101.50	100.88	99.00	97.95	96.37	96.76	94.51	91.24	86.27	77.93	77.87
	TSP	100	101.52	100.93	98.98	98.01	96.67	95.16	93.29	90.21	85.65	77.61	78.41

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,226	1,104,517
NOx	125.3	2,506
TSP	11.2	224

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Med Load - Med Gas - 500 MW Plant in 1999 with 25% Lower Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	12.9	14.2	14.9	16.1	16.6	16.8	16.7	16.9	32.9	48.8	45.3	55.6	307.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1										109.5	191.3		300.8
C	OWC Cogen 2				470.0							254.2	406.4	1130.6
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**12.9**	**14.2**	**14.9**	**486.1**	**16.6**	**16.8**	**16.7**	**16.9**	**32.9**	**158.3**	**490.8**	**462.0**	**1739.1**
	DSM Programs	9.8	12.6	13.0	13.0	14.5	14.5	14.3	14.4	28.4	43.1	40.7	51.3	269.6
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											292.6	102.2	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									129.7	167.6	(0.0)	(0.0)	297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												51.3	51.3
	Total	9.8	12.6	13.0	13.0	14.5	14.5	**14.3**	**14.4**	**158.1**	**210.7**	**333.3**	**204.8**	**1013.0**
	DSM Programs	3.4	3.7	4.6	4.6	4.6	5.3	5.3	5.3	10.5	15.9	15.1	18.8	97.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**3.4**	**3.7**	4.6	**4.6**	4.6	**5.3**	5.3	**5.3**	10.5	15.9	15.1	18.8	**97.1**
	DSM Programs	26.1	30.5	32.5	33.7	35.7	36.6	36.3	36.6	71.8	107.8	101.1	125.7	674.4
T	Renewable													0.0
O	Cogeneration				470.0						109.5	738.1	508.6	1826.2
T	Combined Cycle CT									129.7	167.6	(0.0)	(0.0)	297.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												51.3	51.3
	Total	**26.1**	**30.5**	**32.5**	**503.7**	**35.7**	**36.6**	**36.3**	**36.6**	**201.5**	**384.9**	**839.2**	**685.6**	**2849.2**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	**Native Load**	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	**Firm Sales**	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	**DSM Programs**	(26)	(57)	(89)	(123)	(159)	(195)	(231)	(268)	(340)	(448)	(549)	(674)
T	**Total Requirements**	9,028	9,159	9,268	9,375	9,592	9,595	9,771	9,940	9,952	10,102	10,587	11,035
E													
M	**Existing Generation**	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources				470	470	470	470	470	600	877	1,615	2,175
&	Summer Purch $6/Year												
R	**Total Resources**	10,250	10,741	10,804	11,278	11,287	11,278	11,278	11,257	11,146	11,315	11,858	12,359
	Reserves	1,222	1,582	1,536	1,903	1,696	1,683	1,507	1,317	1,194	1,212	1,271	1,324
	Reserve Margin (RM) (%)	13.5	17.3	16.6	20.3	17.7	17.5	15.4	13.3	12.0	12.0	12.0	12.0

Med Load - Med Gas - 500 MW Plant in 1999
with 25% Lower Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.3	19.5	21.3	22.8	23.7	23.9	23.9	24.2	47.1	69.4	63.2	76.3	431.6
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1										116.5	203.5		320.0
C	OWC Cogen 2				500.0							270.4	432.4	1202.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**16.3**	**19.5**	**21.3**	522.8	**23.7**	**23.9**	**23.9**	**24.2**	**47.1**	**185.9**	**537.1**	**508.7**	**1954.4**
	DSM Programs	12.3	15.2	16.1	16.2	17.7	17.5	17.3	17.4	34.0	51.3	47.8	59.3	322.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											311.2	108.8	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									144.5	186.8	(0.0)	(0.0)	331.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage												51.3	51.3
	Total	**12.3**	**15.2**	**16.1**	**16.2**	**17.7**	**17.5**	**17.3**	**17.4**	**178.5**	**238.1**	**359.0**	**219.4**	**1124.7**
	DSM Programs	2.9	3.3	4.1	4.2	4.2	4.9	4.9	4.9	9.7	14.7	13.7	17.1	88.6
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	2.9	3.3	4.1	4.2	4.2	4.9	4.9	4.9	9.7	14.7	13.7	17.1	88.6
	DSM Programs	31.5	38.0	41.5	43.2	45.6	46.3	46.1	46.5	90.8	135.4	124.7	152.7	842.3
T	Renewable													0.0
O	Cogeneration				500.0						116.5	785.1	541.2	1942.8
T	Combined Cycle CT									144.5	186.8	(0.0)	(0.0)	331.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage												51.3	51.3
	Total	**31.5**	**38.0**	**41.5**	**543.2**	**45.6**	**46.3**	**46.1**	**46.5**	**235.3**	**438.7**	**909.8**	**745.2**	**3167.7**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(32)	(70)	(111)	(154)	(200)	(246)	(292)	(339)	(430)	(565)	(690)	(842)
T	**Total Requirements**	**9,001**	**9,025**	**9,088**	**9,103**	**9,198**	**9,346**	**9,499**	**9,668**	**9,670**	**9,904**	**10,266**	**10,680**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,162	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources				500	500	500	500	500	645	948	1,733	2,325
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,541**	**11,526**	**11,518**	**11,520**	**11,516**	**11,125**	**11,264**	**11,895**	**12,463**
	Reserves	1,348	1,826	1,932	2,438	2,328	2,172	2,021	1,848	1,456	1,360	1,628	1,784
	Reserve Margin (RM) (%)	15.0	20.2	21.3	26.8	25.3	23.2	21.3	19.1	15.0	13.7	15.9	16.7

Med Load - Med Gas - 500 MW Plant in 1999 with 25% Lower Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	8.0	16.7	25.9	36.2	46.7	57.4	68.0	78.7	99.7	130.8	159.7	195.2
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1										108.5	297.9	297.9
C	OWC Cogen 2				400.0	400.0	400.0	400.0	400.0	400.0	400.0	616.4	962.2
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**8.0**	**16.7**	**25.9**	**436.2**	**446.7**	**457.4**	**468.0**	**478.7**	**499.7**	**639.2**	**1,073.9**	**1,455.3**
	DSM Programs	6.6	15.4	24.5	33.6	44.2	54.6	65.1	75.5	96.2	127.5	157.4	195.1
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											249.0	336.0
T	Utah Combined Cycle												
A	Utah Gadsby Repower									49.5	117.3	113.4	113.4
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												0.2
	Total	**6.6**	**15.4**	**24.5**	**33.6**	**44.2**	**54.6**	**65.1**	**75.5**	**145.6**	**244.9**	**519.8**	**644.7**
	DSM Programs	2.4	5.0	8.4	11.8	15.3	19.4	23.5	27.6	35.7	48.0	59.8	74.6
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**2.4**	**5.0**	**8.4**	**11.8**	**15.3**	**19.4**	**23.5**	**27.6**	**35.7**	**48.0**	**59.8**	**74.6**
	DSM Programs	16.9	37.1	58.8	81.6	106.2	131.4	156.6	181.9	231.5	306.3	376.9	465.0
T	Renewable												
O	Cogeneration				400.0	400.0	400.0	400.0	400.0	400.0	508.5	1,163.2	1,596.1
T	Combined Cycle CT									49.5	117.3	113.4	113.4
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												0.2
	Total	**16.9**	**37.1**	**58.8**	**481.6**	**506.2**	**531.4**	**556.6**	**581.9**	**681.0**	**932.1**	**1,653.5**	**2,174.6**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.2
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	495.8	459.6	472.2	602.3	679.6	663.6	630.8	597.7	673.5	633.9	802.1	1,074.6
E	**DSM Programs**	(16.9)	(37.1)	(58.8)	(81.6)	(106.2)	(131.4)	(156.6)	(181.9)	(231.5)	(306.3)	(376.9)	(465.0)
M	**Total Requirements**	7,809.5	7,772.2	7,779.7	7,956.7	8,142.9	8,199.1	8,283.8	8,345.9	8,475.1	8,657.5	9,117.9	9,575.4
	Existing Generation	7,161.5	7,066.5	7,085.0	6,929.2	7,187.2	7,245.6	7,357.3	7,415.1	7,518.8	7,454.9	7,354.8	7,457.4
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	91.0	202.0	221.8	162.8	101.6	107.9	84.3	91.7	107.3	195.0	107.9	49.9
R	**New Resources**				400.0	400.0	400.0	400.0	400.0	449.5	625.8	1,276.6	1,709.6
	Total Resources	7,809.5	7,772.2	7,779.7	7,956.7	8,142.9	8,199.1	8,283.8	8,345.9	8,475.1	8,657.5	9,117.9	9,575.4

Med Load - Med Gas - 500 MW Plant in 1999
with 25% Lower Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	17	37	58	81	106	131	156	181	232	307	376	469
			After Conservation												
			System Load (MWa)	5,707	5,690	5,736	5,824	5,952	6,049	6,167	6,297	6,541	6,935	7,284	7,674
	0.53		Energy Sales (MWa)	5,158	5,169	5,232	5,325	5,427	5,533	5,642	5,752	5,921	6,164	6,491	6,646
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,093	8,473	8,903	9,090	9,239	9,406	9,587	9,846	10,339	11,455	13,290	15,155
			Net Conservation Assets ($M)	39	83	130	163	196	229	259	288	339	396	426	470
			Utility Cost												
43,641	3.34	Nominal	**Operating Revenues ($M)**	2,212	2,223	2,263	2,371	2,535	2,654	2,733	2,826	3,033	3,413	3,967	4,660
	0.04	Real		2,212	2,152	2,120	2,151	2,226	2,256	2,250	2,251	2,265	2,312	2,437	2,514
	2.80	Nominal	Cost in mills/kWh	49.0	49.1	49.4	50.8	53.3	54.8	55.3	56.1	58.5	63.2	69.8	80.0
	-0.49	Real		49.0	47.5	46.3	46.1	46.8	46.6	45.5	44.7	43.7	42.8	42.9	43.2
		Nominal	Average Customer Bill ($)	1,668	1,660	1,667	1,718	1,804	1,858	1,883	1,914	1,990	2,134	2,379	2,722
		Real		1,668	1,607	1,562	1,559	1,585	1,580	1,550	1,525	1,486	1,446	1,462	1,469
			Total Resource Cost												
			DSR Customer Cost ($M)	0.6	1.4	2.1	4.6	6.8	8.9	10.5	11.7	12.1	7.0	-3.6	-28.8
			Levelized (20-year at 8.6%)	0.1	0.2	0.4	0.9	1.7	2.6	3.7	5.0	7.5	10.5	11.0	11.0
			Energy Svc Charge ($M)	3.2	7.1	11.4	14.3	17.4	20.7	24.1	27.6	35.0	46.7	56.0	60.2
44,051	3.34	Nominal	**Total Resource Cost ($M)**	2,216	2,230	2,274	2,386	2,554	2,677	2,761	2,859	3,076	3,470	4,034	4,731
	0.04	Real		2,216	2,159	2,131	2,164	2,243	2,276	2,273	2,277	2,296	2,350	2,479	2,553
	2.66	Nominal	Cost in mills/kWh	48.9	48.9	49.1	50.5	52.8	54.1	54.5	55.1	57.3	61.5	67.4	76.3
	-0.61	Real		48.9	47.4	46.0	45.8	46.4	46.0	44.9	43.9	42.7	41.6	41.4	41.2

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.53

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 42.08

Med Load - Med Gas - 500 MW Plant in 1999
with 25% Lower Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	50,001	49,845	50,241	50,990	52,111	52,959	53,989	55,131	57,256	60,713	67,210	66,836
	MWa	5,708	5,690	5,735	5,821	5,949	6,046	6,163	6,294	6,536	6,931	7,672	7,630
	Total Annual Emissions (1000 Tons)												
0.20%	CO2	51,963	49,460	49,511	48,970	50,933	51,614	52,675	53,481	54,968	56,642	58,349	53,955
0.20%	NOx	121.1	113.0	113.0	110.0	115.1	116.3	121.0	122.1	123.9	123.5	123.7	125.8
0.24%	TSP	10.9	10.1	10.1	10.2	10.3	10.4	10.6	10.7	10.9	11.0	11.0	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.32%	CO2	2,078	1,985	1,971	1,921	1,955	1,949	1,951	1,940	1,920	1,866	1,736	1,615
-1.32%	NOx	4.85	4.53	4.50	4.32	4.42	4.39	4.48	4.43	4.33	4.07	3.68	3.76
-1.28%	TSP	0.43	0.41	0.40	0.40	0.40	0.39	0.39	0.39	0.38	0.36	0.33	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	95.48	94.83	92.41	94.05	93.78	93.88	93.35	92.38	89.77	83.54	77.68
	NOx	100	93.54	92.83	89.06	91.18	90.61	92.52	91.44	89.32	83.97	75.97	77.68
	TSP	100	93.31	92.80	91.62	90.92	90.19	90.18	89.14	87.84	83.26	75.46	78.28

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,090	1,081,802
NOx	121.0	2,421
TSP	10.8	216

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Med Load - Med Gas - 500 MW Plant in 1999 with Medium Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	12.9	15.4	15.8	16.2	16.8	17.1	17.0	17.0	33.5	49.7	46.1	56.7	314.2
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1										234.5	66.3		300.8
C	OWC Cogen 2				470.0							361.3	409.5	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	12.9	15.4	15.8	486.2	16.8	17.1	17.0	17.0	33.5	284.2	473.7	466.2	1855.8
	DSM Programs	11.4	12.5	13.0	14.4	14.5	14.4	14.4	14.4	28.4	43.0	40.8	50.9	272.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											309.5	85.3	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									120.6	41.7		64.2	226.5
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	11.4	12.5	13.0	14.4	14.5	14.4	14.4	14.4	149.0	84.7	350.3	200.4	893.4
	DSM Programs	3.5	4.5	4.6	4.6	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.8	98.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	3.5	4.5	4.6	4.6	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.8	98.5
	DSM Programs	27.8	32.4	33.4	35.2	36.6	36.8	36.7	36.7	72.3	108.6	101.9	126.4	684.8
T	Renewable													0.0
O	Cogeneration				470.0						234.5	737.1	494.8	1936.4
T	Combined Cycle CT									120.6	41.7		64.2	226.5
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	27.8	32.4	33.4	505.2	36.6	36.8	36.7	36.7	192.9	384.8	839.0	685.4	2847.7

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(28)	(60)	(94)	(129)	(165)	(202)	(239)	(276)	(348)	(457)	(558)	(685)
T	Total Requirements	9,026	9,156	9,263	9,369	9,585	9,588	9,763	9,932	9,944	10,094	10,578	11,024
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,122	10,013	9,868	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources				470	470	470	470	470	591	867	1,604	2,163
&	Summer Purch $6/Year												
R	Total Resources	10,250	10,741	10,804	11,278	11,287	11,278	11,278	11,257	11,137	11,304	11,846	12,347
	Reserves	1,224	1,585	1,541	1,909	1,702	1,690	1,515	1,325	1,193	1,211	1,269	1,323
	Reserve Margin (RM) (%)	13.6	17.3	16.6	20.4	17.8	17.6	15.5	13.3	12.0	12.0	12.0	12.0

Med Load - Med Gas - 500 MW Plant in 1999
with Medium Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.3	21.2	22.3	23.1	24.1	24.5	24.5	24.9	48.7	71.9	65.7	79.6	446.8
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1										249.4	70.6		320.0
C	OWC Cogen 2				500.0							384.4	435.6	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**16.3**	**21.2**	**22.3**	**523.1**	**24.1**	**24.5**	**24.5**	**24.9**	**48.7**	**321.3**	**520.7**	**515.2**	**2086.8**
	DSM Programs	13.8	15.3	16.1	17.5	17.6	17.6	17.3	17.3	34.1	51.3	47.7	59.1	324.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											329.2	90.8	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									134.4	46.4		71.6	252.4
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**15.3**	**16.1**	**17.5**	**17.6**	**17.6**	**17.3**	**17.3**	**168.5**	**97.7**	**376.9**	**221.5**	**997.1**
	DSM Programs	3.1	4.1	4.1	4.2	4.9	4.9	4.8	5.0	9.6	14.7	13.7	17.0	90.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	3.1	4.1	4.1	4.2	4.9	4.9	4.8	5.0	9.6	14.7	13.7	17.0	90.1
	DSM Programs	33.2	40.6	42.5	44.8	46.6	47.0	46.6	47.2	92.4	137.9	127.1	155.7	861.6
T	Renewable													0.0
O	Cogeneration				500.0						249.4	784.2	526.4	2060.0
T	Combined Cycle CT									134.4	46.4		71.6	252.4
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**33.2**	**40.6**	**42.5**	**544.8**	**46.6**	**47.0**	**46.6**	**47.2**	**226.8**	**433.7**	**911.3**	**753.7**	**3174.0**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(33)	(74)	(116)	(161)	(208)	(255)	(301)	(349)	(441)	(579)	(706)	(862)
T	**Total Requirements**	**8,999**	**9,020**	**9,083**	**9,096**	**9,190**	**9,337**	**9,490**	**9,659**	**9,658**	**9,890**	**10,250**	**10,660**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,046	9,892	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources				500	500	500	500	500	634	930	1,714	2,312
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,541**	**11,526**	**11,518**	**11,520**	**11,516**	**11,115**	**11,246**	**11,876**	**12,451**
	Reserves	1,349	1,830	1,937	2,445	2,336	2,181	2,030	1,858	1,457	1,355	1,626	1,790
	Reserve Margin (RM) (%)	15.0	20.3	21.3	26.9	25.4	23.3	21.4	19.2	15.1	13.7	15.9	16.8

Med Load - Med Gas - 500 MW Plant in 1999 with Medium Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	8.0	17.7	27.8	38.2	49.0	60.0	71.0	82.0	103.8	136.2	166.4	203.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1										232.2	297.9	297.9
C	OWC Cogen 2				444.2	444.2	444.3	465.2	465.2	465.2	465.2	796.0	1,101.7
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	8.0	17.7	27.8	482.3	493.2	504.3	536.2	547.3	569.0	833.6	1,260.3	1,603.2
	DSM Programs	8.1	16.9	26.0	36.4	47.0	57.5	67.9	78.4	99.0	130.4	160.2	197.7
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											290.3	367.3
T	Utah Combined Cycle												
A	Utah Gadsby Repower									99.5	136.7	109.9	116.4
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	8.1	16.9	26.0	36.4	47.0	57.5	67.9	78.4	198.5	267.1	560.5	681.4
	DSM Programs	2.5	5.8	9.2	12.7	16.8	20.9	25.0	29.1	37.2	49.5	61.3	76.1
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	2.5	5.8	9.2	12.7	16.8	20.9	25.0	29.1	37.2	49.5	61.3	76.1
	DSM Programs	18.6	40.5	63.0	87.3	112.7	138.3	163.8	189.5	240.0	316.0	387.9	477.4
T	Renewable												
O	Cogeneration				444.2	444.2	444.3	465.2	465.2	465.2	697.4	1,384.2	1,766.9
T	Combined Cycle CT									99.5	136.7	109.9	116.4
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	18.6	40.5	63.0	531.5	556.9	582.6	629.0	654.7	804.7	1,150.2	1,882.0	2,360.7
S	Native Load	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	Pump Storage/Peak Return	310.6	310.2	309.8	307.2	307.0	307.0	306.7	307.0	305.0	305.0	305.0	305.0
S	Firm Sales	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	Non-Firm Sales	495.9	752.9	781.8	1,019.6	969.3	964.0	913.6	859.5	918.6	944.0	1,132.7	1,244.1
E	DSM Programs	(18.6)	(40.5)	(63.0)	(87.3)	(112.7)	(138.3)	(163.8)	(189.5)	(240.0)	(316.0)	(387.9)	(477.4)
M	Total Requirements	7,807.9	8,062.1	8,085.0	8,368.2	8,426.1	8,492.6	8,559.1	8,600.1	8,711.8	8,957.9	9,437.5	9,732.3
	Existing Generation	7,161.3	7,516.6	7,579.9	7,459.4	7,527.8	7,602.8	7,647.3	7,672.2	7,741.7	7,724.0	7,564.8	7,490.5
L	Firm Purchases	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	Non-Firm Purchases	89.6	41.9	32.2				4.4	23.6	5.8	18.0		
R	New Resources				444.2	444.2	444.3	465.2	465.2	564.8	834.2	1,494.1	1,883.3
	Total Resources	7,807.9	8,062.1	8,085.0	8,368.3	8,426.1	8,492.6	8,559.2	8,600.1	8,711.8	8,957.9	9,437.5	9,732.3

Med Load - Med Gas - 500 MW Plant in 1999
with Medium Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	18	40	63	87	112	138	163	189	241	317	388	483
			After Conservation												
			System Load (MWa)	5,706	5,687	5,732	5,818	5,946	6,042	6,159	6,289	6,532	6,925	7,272	7,660
	0.52		Energy Sales (MWa)	5,156	5,166	5,228	5,319	5,421	5,527	5,635	5,744	5,913	6,155	6,480	6,633
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,097	8,479	8,911	9,099	9,250	9,417	9,598	9,851	10,342	11,509	13,249	15,136
			Net Conservation Assets ($M)	42	89	137	173	207	240	270	300	352	410	439	485
			Utility Cost												
42,767	3.28	Nominal	**Operating Revenues ($M)**	2,212	2,198	2,237	2,335	2,495	2,613	2,691	2,785	2,968	3,358	3,896	4,524
	-0.02	Real		2,212	2,127	2,096	2,118	2,191	2,222	2,215	2,218	2,216	2,274	2,394	2,442
	2.74	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.1	52.5	54.0	54.5	55.3	57.3	62.3	68.6	77.9
	-0.54	Real		49.0	47.0	45.8	45.5	46.1	45.9	44.9	44.1	42.8	42.2	42.2	42.0
		Nominal	Average Customer Bill ($)	1,668	1,641	1,648	1,692	1,776	1,830	1,854	1,886	1,947	2,100	2,336	2,643
		Real		1,668	1,588	1,544	1,535	1,560	1,556	1,526	1,503	1,454	1,422	1,436	1,426
			Total Resource Cost												
			DSR Customer Cost ($M)	0.7	1.6	2.4	4.7	6.8	8.7	10.3	11.5	11.8	6.6	-3.8	-28.9
			Levelized (20-year at 8.6%)	0.1	0.2	0.5	1.0	1.7	2.6	3.7	5.0	7.5	10.3	10.8	10.8
			Energy Svc Charge ($M)	3.5	7.8	12.3	15.3	18.5	21.9	25.3	28.8	36.2	48.0	57.1	60.6
43,187	3.28	Nominal	**Total Resource Cost ($M)**	2,216	2,206	2,250	2,351	2,516	2,638	2,720	2,818	3,012	3,416	3,964	4,596
	-0.02	Real		2,216	2,135	2,108	2,133	2,209	2,243	2,239	2,245	2,249	2,314	2,435	2,480
	2.60	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.7	52.0	53.3	53.7	54.4	56.1	60.5	66.2	74.2
	-0.67	Real		48.9	46.9	45.5	45.1	45.7	45.3	44.2	43.3	41.9	41.0	40.7	40.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.73**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.25**

Med Load - Med Gas - 500 MW Plant in 1999
with Medium Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,987	49,815	50,203	50,940	52,054	52,899	53,924	55,065	57,183	60,628	67,100	66,756
	MWa	5,706	5,687	5,731	5,815	5,942	6,039	6,156	6,286	6,528	6,921	7,660	7,621
	Total Annual Emissions (1000 Tons)												
0.14%	CO2	51,956	51,968	52,142	51,868	52,676	53,496	54,100	54,692	55,708	57,537	59,222	53,316
0.21%	NOx	121.1	121.5	121.9	119.9	121.0	122.6	126.0	126.4	126.6	126.8	126.9	126.1
0.25%	TSP	10.9	10.9	10.9	10.8	10.8	11.0	11.1	11.1	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.38%	CO2	2,079	2,086	2,077	2,036	2,024	2,023	2,007	1,986	1,948	1,898	1,765	1,597
-1.30%	NOx	4.85	4.88	4.86	4.71	4.65	4.64	4.67	4.59	4.43	4.18	3.78	3.78
-1.27%	TSP	0.43	0.44	0.44	0.42	0.42	0.42	0.41	0.40	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.37	99.93	97.96	97.36	97.30	96.53	95.56	93.73	91.31	84.91	76.84
	NOx	100	100.68	100.22	97.13	95.94	95.66	96.38	94.68	91.33	86.32	78.05	77.92
	TSP	100	100.51	100.13	97.38	95.75	95.66	94.50	92.98	90.14	85.64	77.62	78.47

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,134	1,102,690
NOx	125.0	2,500
TSP	11.2	223

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Med Load - Med Gas - 500 MW Plant in 1999 with 25% Higher Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	13.0	15.3	15.9	16.3	16.7	16.8	16.9	16.9	33.1	49.1	45.6	55.9	311.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1										285.1	15.7		300.8
C	OWC Cogen 2				470.0							369.9	400.9	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	13.0	15.3	15.9	486.3	16.7	16.8	16.9	16.9	33.1	334.2	431.2	456.8	1853.1
	DSM Programs	11.4	12.5	13.0	14.4	14.5	14.4	14.4	14.4	28.4	43.0	40.8	50.9	272.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											235.7	159.1	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								135.4	33.5	60.3			229.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	11.4	12.5	13.0	14.4	14.5	14.4	14.4	149.8	61.9	103.3	276.5	210.0	896.1
	DSM Programs	3.9	4.5	4.5	4.6	5.3	5.3	5.3	5.3	10.5	15.8	15.1	18.8	98.9
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	3.9	4.5	4.5	4.6	5.3	5.3	5.3	5.3	10.5	15.8	15.1	18.8	98.9
	DSM Programs	28.3	32.3	33.4	35.3	36.5	36.5	36.6	36.6	72.0	107.9	101.5	125.6	682.5
T	Renewable													0.0
O	Cogeneration				470.0						285.1	621.3	560.0	1936.4
T	Combined Cycle CT								135.4	33.5	60.3			229.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	28.3	32.3	33.4	505.3	36.5	36.5	36.6	172.0	105.5	453.3	722.8	685.6	2848.1

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(28)	(61)	(94)	(129)	(166)	(202)	(239)	(276)	(348)	(455)	(557)	(683)
T	Total Requirements	9,026	9,155	9,263	9,369	9,584	9,588	9,763	9,933	9,945	10,095	10,579	11,027
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,122	10,013	9,868	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources				470	470	470	470	605	639	984	1,606	2,166
&	Summer Purch $6/Year												
R	Total Resources	10,250	10,741	10,804	11,278	11,287	11,278	11,278	11,392	11,165	11,421	11,848	12,350
	Reserves	1,224	1,586	1,541	1,909	1,703	1,690	1,515	1,460	1,241	1,327	1,269	1,323
	Reserve Margin (RM) (%)	13.6	17.3	16.6	20.4	17.8	17.6	15.5	14.7	12.5	13.2	12.0	12.0

Med Load - Med Gas - 500 MW Plant in 1999
with 25% Higher Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.6	21.4	22.6	23.3	24.2	24.6	24.6	24.8	48.5	71.5	65.0	78.7	445.8
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1										303.3	16.7		320.0
C	OWC Cogen 2				500.0							393.5	426.5	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**16.6**	**21.4**	**22.6**	**523.3**	**24.2**	**24.6**	**24.6**	**24.8**	**48.5**	**374.8**	**475.2**	**505.2**	**2085.8**
	DSM Programs	13.8	15.3	16.1	17.5	17.6	17.6	17.3	17.3	34.1	51.3	47.7	59.1	324.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											250.8	169.2	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								150.8	37.4	67.2			255.4
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**15.3**	**16.1**	**17.5**	**17.6**	**17.6**	**17.3**	**168.1**	**71.5**	**118.5**	**298.5**	**228.3**	**1000.1**
	DSM Programs	3.5	4.1	4.0	4.2	4.9	4.9	4.9	4.9	9.7	14.6	13.8	17.0	90.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**3.5**	**4.1**	**4.0**	**4.2**	**4.9**	**4.9**	**4.9**	**4.9**	**9.7**	**14.6**	**13.8**	**17.0**	**90.5**
	DSM Programs	33.9	40.8	42.7	45.0	46.7	47.1	46.8	47.0	92.3	137.4	126.5	154.8	861.0
T	Renewable													0.0
O	Cogeneration				500.0						303.3	661.0	595.7	2060.0
T	Combined Cycle CT								150.8	37.4	67.2			255.4
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**33.9**	**40.8**	**42.7**	**545.0**	**46.7**	**47.1**	**46.8**	**197.8**	**129.7**	**507.9**	**787.5**	**750.5**	**3176.4**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(34)	(75)	(117)	(162)	(209)	(256)	(303)	(350)	(442)	(580)	(706)	(861)
T	**Total Requirements**	**8,998**	**9,019**	**9,082**	**9,095**	**9,189**	**9,336**	**9,488**	**9,657**	**9,657**	**9,889**	**10,250**	**10,661**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,892	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources				500	500	500	500	651	688	1,059	1,720	2,315
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,541**	**11,526**	**11,518**	**11,520**	**11,667**	**11,169**	**11,375**	**11,881**	**12,454**
	Reserves	1,350	1,831	1,938	2,446	2,337	2,182	2,032	2,010	1,512	1,486	1,631	1,793
	Reserve Margin (RM) (%)	15.0	20.3	21.3	26.9	25.4	23.4	21.4	20.8	15.6	15.0	15.9	16.8

Med Load - Med Gas - 500 MW Plant in 1999 with 25% Higher Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	8.0	17.9	28.1	38.6	49.3	60.3	71.2	82.1	103.6	135.5	165.2	201.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1										282.3	297.9	297.9
C	OWC Cogen 2				444.2	444.2	444.2	465.2	465.2	465.2	459.4	807.1	1,101.4
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**8.0**	**17.9**	**28.1**	**482.8**	**493.5**	**504.4**	**536.4**	**547.4**	**568.8**	**877.2**	**1,270.1**	**1,601.0**
	DSM Programs	8.1	16.9	26.0	36.4	47.0	57.5	67.9	78.4	99.0	130.4	160.2	197.7
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											227.2	367.3
T	Utah Combined Cycle												
A	Utah Gadsby Repower								104.7	148.3	204.6	169.2	118.3
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**8.1**	**16.9**	**26.0**	**36.4**	**47.0**	**57.5**	**67.9**	**183.0**	**247.3**	**335.0**	**556.6**	**683.3**
	DSM Programs	3.0	6.3	9.7	13.1	17.2	21.3	25.4	29.5	37.6	49.9	61.8	76.5
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.0**	**6.3**	**9.7**	**13.1**	**17.2**	**21.3**	**25.4**	**29.5**	**37.6**	**49.9**	**61.8**	**76.5**
	DSM Programs	19.2	41.2	63.8	88.2	113.5	139.0	164.5	190.0	240.2	315.8	387.2	475.9
T	Renewable												
O	Cogeneration				444.2	444.2	444.2	465.2	465.2	465.2	741.7	1,332.1	1,766.6
T	Combined Cycle CT								104.7	148.3	204.6	169.2	118.3
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**19.2**	**41.2**	63.8	**532.3**	557.7	583.2	629.7	**759.9**	**853.8**	**1,262.1**	**1,888.4**	**2,360.8**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.7	307.2	306.7	307.0	306.7	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	496.2	784.1	882.2	1,043.5	1,002.6	1,011.7	961.1	1,008.6	1,011.0	1,081.6	1,167.1	1,245.3
E	**DSM Programs**	(19.2)	(41.2)	(63.8)	(88.1)	(113.5)	(139.0)	(164.5)	(190.0)	(240.2)	(315.8)	(387.2)	(475.9)
M	**Total Requirements**	7,807.6	8,092.7	8,184.5	8,391.3	8,458.3	8,539.6	8,605.9	8,748.6	8,803.9	9,095.6	9,472.7	9,735.0
	Existing Generation	7,161.2	7,565.4	7,680.0	7,482.5	7,560.1	7,649.9	7,698.5	7,739.6	7,790.8	7,766.3	7,592.8	7,491.5
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	89.4	23.6	31.6							1.2		
R	**New Resources**				444.2	444.2	444.2	465.2	569.9	613.5	946.3	1,501.3	1,884.9
	Total Resources	7,807.6	8,092.7	8,184.5	8,391.4	8,458.3	8,539.6	8,605.9	8,748.6	8,803.9	9,095.6	9,472.7	9,735.0

Med Load - Med Gas - 500 MW Plant in 1999
with 25% Higher Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	19	41	63	88	113	139	164	189	241	317	387	481
			After Conservation												
			System Load (MWa)	5,705	5,686	5,731	5,818	5,945	6,042	6,159	6,289	6,532	6,925	7,273	7,661
	0.53		Energy Sales (MWa)	5,156	5,165	5,227	5,318	5,421	5,526	5,635	5,744	5,913	6,155	6,481	6,635
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,098	8,481	8,913	9,101	9,260	9,504	9,773	9,968	10,393	11,666	13,181	15,072
			Net Conservation Assets ($M)	43	91	139	175	209	241	272	300	352	409	438	483
			Utility Cost												
41,779	3.22	Nominal	**Operating Revenues ($M)**	2,212	2,168	2,206	2,292	2,452	2,569	2,647	2,693	2,916	3,259	3,796	4,397
	-0.08	Real		2,212	2,099	2,067	2,079	2,154	2,184	2,179	2,146	2,177	2,207	2,332	2,372
	2.68	Nominal	Cost in mills/kWh	49.0	47.9	48.2	49.2	51.7	53.1	53.6	53.5	56.3	60.4	66.9	75.7
	-0.60	Real		49.0	46.4	45.2	44.6	45.4	45.1	44.1	42.6	42.0	40.9	41.1	40.8
		Nominal	Average Customer Bill ($)	1,668	1,619	1,625	1,661	1,745	1,799	1,824	1,824	1,913	2,038	2,276	2,568
		Real		1,668	1,567	1,523	1,507	1,533	1,529	1,501	1,454	1,428	1,380	1,399	1,386
			Total Resource Cost												
			DSR Customer Cost ($M)	0.4	1.3	2.0	4.5	6.8	8.6	10.2	11.4	11.7	6.5	-4.0	-29.2
			Levelized (20-year at 8.6%)	0.1	0.2	0.4	0.9	1.6	2.5	3.6	4.8	7.3	10.1	10.5	10.5
			Energy Svc Charge ($M)	3.6	7.9	12.4	15.4	18.6	21.9	25.3	28.8	36.2	47.9	56.8	60.2
42,196	3.21	Nominal	**Total Resource Cost ($M)**	2,216	2,176	2,219	2,308	2,473	2,593	2,676	2,727	2,959	3,317	3,863	4,467
	-0.08	Real		2,216	2,107	2,079	2,094	2,171	2,205	2,203	2,173	2,210	2,246	2,374	2,411
	2.54	Nominal	Cost in mills/kWh	48.9	47.8	47.9	48.8	51.1	52.4	52.8	52.6	55.1	58.7	64.5	72.1
	-0.74	Real		48.9	46.2	44.9	44.3	44.9	44.5	43.5	41.9	41.1	39.8	39.6	38.9

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.74**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.31**

Med Load - Med Gas - 500 MW Plant in 1999
with 25% Higher Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,982	49,809	50,196	50,933	52,044	52,893	53,917	55,060	57,180	60,629	67,113	66,787
	MWa	5,706	5,686	5,730	5,814	5,941	6,038	6,155	6,285	6,527	6,921	7,661	7,624
	Total Annual Emissions (1000 Tons)												
0.14%	CO2	51,953	52,260	52,399	51,920	52,787	53,611	54,216	54,654	55,687	57,461	59,183	53,311
0.21%	NOx	121.1	122.5	122.7	120.1	121.4	123.0	126.4	126.2	126.5	126.6	126.7	126.1
0.25%	TSP	10.9	11.0	11.0	10.8	10.9	11.0	11.1	11.1	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.38%	CO2	2,079	2,098	2,088	2,039	2,029	2,027	2,011	1,985	1,948	1,896	1,764	1,596
-1.31%	NOx	4.85	4.92	4.89	4.71	4.66	4.65	4.69	4.58	4.42	4.17	3.78	3.78
-1.27%	TSP	0.43	0.44	0.44	0.42	0.42	0.42	0.41	0.40	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.94	100.43	98.07	97.58	97.51	96.74	95.50	93.69	91.18	84.84	76.79
	NOx	100	101.50	100.86	97.27	96.23	95.93	96.72	94.53	91.28	86.12	77.91	77.88
	TSP	100	101.51	100.91	97.56	96.12	95.99	94.82	93.09	90.12	85.49	77.59	78.44

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,157	1,103,147
NOx	125.1	2,501
TSP	11.2	223

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Med Load - Med Gas - Underbuild
with 25% Lower Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.1	15.4	16.1	16.3	16.8	17.0	16.9	17.0	33.3	49.2	45.8	56.0	313.9
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									85.9	214.9			300.8
C	OWC Cogen 2											615.9	386.3	1002.2
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.1**	**15.4**	**16.1**	**16.3**	**16.8**	**17.0**	**16.9**	**17.0**	119.2	264.1	661.7	442.3	1616.9
	DSM Programs	12.1	12.6	14.3	14.3	14.6	14.4	14.4	14.4	28.3	43.1	40.8	50.8	274.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2										61.7	121.7	173.9	357.3
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									168.0				168.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT								330.6					330.6
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	12.1	12.6	**14.3**	14.3	**14.6**	**14.4**	14.4	**345.0**	**196.3**	**104.8**	162.5	224.7	1130.0
	DSM Programs	4.5	4.5	5.2	5.2	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.7	100.6
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.5**	**4.5**	**5.2**	**5.2**	**5.3**	**5.3**	**5.3**	**5.3**	**10.4**	**15.9**	**15.0**	**18.7**	**100.6**
	DSM Programs	30.7	32.5	35.6	35.8	36.7	36.7	36.6	36.7	72.0	108.2	101.6	125.5	688.6
T	Renewable													0.0
O	Cogeneration									85.9	276.6	737.6	560.2	1660.3
T	Combined Cycle CT									168.0				168.0
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT								330.6					330.6
	Pumped Storage													0.0
	Total	**30.7**	**32.5**	**35.6**	**35.8**	**36.7**	**36.7**	**36.6**	**367.3**	**325.9**	**384.8**	**839.2**	**685.7**	**2847.5**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(31)	(63)	(99)	(135)	(171)	(208)	(245)	(281)	(353)	(462)	(563)	(689)
T	**Total Requirements**	9,023	9,153	9,258	9,363	9,579	9,582	9,757	9,927	9,939	10,089	10,573	11,020
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources								331	585	861	1,599	2,159
&	Summer Purch $6/Year							121					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,929	11,118	11,131	11,299	11,842	12,343
	Reserves	1,227	1,588	1,546	1,445	1,238	1,226	1,172	1,191	1,193	1,210	1,269	1,322
	Reserve Margin (RM) (%)	13.6	17.3	16.7	15.4	12.9	12.8	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas - Underbuild with 25% Lower Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.0	21.3	22.6	23.1	23.9	24.1	24.1	24.3	47.4	69.6	63.3	76.6	438.3
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									91.4	228.6			320.0
C	OWC Cogen 2											655.2	410.9	1066.1
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.0**	**21.3**	**22.6**	**23.1**	**23.9**	**24.1**	**24.1**	**24.3**	**138.8**	**298.2**	**718.5**	**487.5**	**1824.4**
	DSM Programs	14.4	15.2	17.5	17.5	17.6	17.6	17.3	17.3	34.1	51.3	47.7	59.0	326.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2										65.6	129.6	184.9	380.1
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									187.2				187.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT								351.7					351.7
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**14.4**	**15.2**	**17.5**	**17.5**	**17.6**	**17.6**	**17.3**	**369.0**	**221.3**	**116.9**	**177.3**	**243.9**	**1245.5**
	DSM Programs	4.0	4.1	4.8	4.7	4.9	4.9	4.9	4.9	9.7	14.6	13.7	16.9	92.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.0	4.1	4.8	**4.7**	**4.9**	**4.9**	**4.9**	**4.9**	**9.7**	**14.6**	13.7	16.9	92.1
	DSM Programs	36.4	40.6	44.9	45.3	46.4	46.6	46.3	46.5	91.2	135.5	124.7	152.5	856.9
T	Renewable													0.0
O	Cogeneration									91.4	294.2	784.8	595.8	1766.2
T	Combined Cycle CT									187.2				187.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT								351.7					351.7
	Pumped Storage													0.0
	Total	**36.4**	**40.6**	**44.9**	**45.3**	**46.4**	**46.6**	**46.3**	**398.2**	**369.8**	**429.7**	**909.5**	**748.3**	**3162.0**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(36)	(77)	(122)	(167)	(214)	(260)	(307)	(353)	(444)	(580)	(704)	(857)
T	**Total Requirements**	**8,996**	**9,017**	**9,077**	**9,090**	**9,184**	**9,332**	**9,485**	**9,654**	**9,655**	**9,889**	**10,252**	**10,665**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								352	630	925	1,709	2,305
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,020**	**11,368**	**11,110**	**11,240**	**11,871**	**12,443**
	Reserves	1,352	1,833	1,943	1,951	1,842	1,686	1,536	1,714	1,455	1,351	1,620	1,778
	Reserve Margin (RM) (%)	15.0	20.3	21.4	21.5	20.1	18.1	16.2	17.8	15.1	13.7	15.8	16.7

Med Load - Med Gas - Underbuild with 25% Lower Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.0	18.8	29.1	39.5	50.3	61.1	71.9	82.8	104.0	135.5	164.8	200.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1									85.1	297.9	297.9	297.9
C	OWC Cogen 2											524.2	852.9
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.0**	**18.8**	**29.1**	**39.5**	**50.3**	**61.1**	**71.9**	**82.8**	**189.0**	**433.4**	**986.8**	**1,351.5**
	DSM Programs	8.5	17.3	27.7	38.1	48.6	59.1	69.6	80.0	100.7	132.0	161.9	199.3
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2										54.4	161.3	307.5
T	Utah Combined Cycle												
A	Utah Gadsby Repower									68.2	76.1	66.6	64.1
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT								13.2	13.2	13.2	13.2	13.2
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**8.5**	**17.3**	**27.7**	**38.1**	**48.6**	**59.1**	**69.6**	**93.2**	**182.0**	**275.6**	**403.0**	**584.0**
	DSM Programs	3.3	6.7	10.7	14.8	18.9	23.0	27.1	31.2	39.3	51.6	63.3	78.0
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**6.7**	**10.7**	**14.8**	**18.9**	**23.0**	**27.1**	**31.2**	**39.3**	**51.6**	**63.3**	**78.0**
	DSM Programs	20.8	42.8	67.5	92.4	117.8	143.2	168.5	194.0	244.0	319.1	390.1	478.0
T	Renewable												
O	Cogeneration									85.1	352.2	983.3	1,458.3
T	Combined Cycle CT									68.2	76.1	66.6	64.1
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT								13.2	13.2	13.2	13.2	13.2
	Pumped Storage												
	Total	**20.8**	**42.8**	**67.5**	**92.4**	**117.8**	**143.2**	**168.5**	**207.1**	**410.3**	**760.6**	**1,453.1**	**2,013.5**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	498.5	460.7	478.9	453.9	461.6	438.9	477.9	431.7	501.5	491.9	649.0	960.5
E	**DSM Programs**	(20.8)	(42.8)	(67.5)	(92.4)	(117.8)	(143.2)	(168.5)	(194.0)	(243.9)	(319.1)	(390.1)	(478.0)
M	**Total Requirements**	7,808.3	7,767.6	7,777.7	7,797.5	7,913.3	7,962.6	8,119.0	8,167.8	8,290.6	8,502.7	8,951.7	9,448.0
	Existing Generation	7,161.2	7,064.2	7,083.1	7,113.2	7,250.2	7,286.4	7,481.9	7,497.7	7,520.3	7,465.0	7,362.9	7,460.5
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	90.1	199.6	221.7	219.6	209.0	230.7	194.8	217.9	204.4	214.5	147.1	93.5
R	**New Resources**								13.2	166.4	441.5	1,063.1	1,535.5
	Total Resources	7,808.3	7,767.6	7,777.7	7,797.5	7,913.3	7,962.6	8,119.0	8,167.8	8,290.6	8,502.7	8,951.7	9,448.0

Med Load - Med Gas - Underbuild
with 25% Lower Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	21	42	67	92	117	142	168	193	244	320	390	483
			After Conservation												
			System Load (MWa)	5,703	5,684	5,727	5,813	5,941	6,038	6,155	6,285	6,529	6,922	7,271	7,660
	0.53		Energy Sales (MWa)	5,154	5,163	5,224	5,315	5,417	5,522	5,631	5,741	5,910	6,153	6,479	6,633
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,079	8,275	8,461	8,662	8,838	9,140	9,493	9,842	10,451	11,589	13,227	15,116
			Net Conservation Assets ($M)	47	94	146	181	214	245	275	303	351	404	429	472
			Utility Cost												
43,707	3.37	Nominal	**Operating Revenues ($M)**	2,211	2,222	2,262	2,353	2,450	2,571	2,665	2,768	3,014	3,459	4,029	4,702
	0.07	Real		2,211	2,151	2,120	2,135	2,151	2,186	2,193	2,205	2,251	2,343	2,476	2,537
	2.83	Nominal	Cost in mills/kWh	49.0	49.1	49.4	50.5	51.6	53.1	54.0	55.1	58.2	64.2	71.0	80.9
	-0.46	Real		49.0	47.6	46.3	45.9	45.3	45.2	44.5	43.9	43.5	43.5	43.6	43.7
		Nominal	Average Customer Bill ($)	1,668	1,659	1,667	1,705	1,743	1,800	1,836	1,875	1,977	2,164	2,416	2,747
		Real		1,668	1,606	1,562	1,547	1,531	1,530	1,511	1,494	1,476	1,465	1,485	1,482
			Total Resource Cost												
			DSR Customer Cost ($M)	0.9	1.8	2.8	5.5	7.9	10.0	11.7	13.0	13.5	8.6	-1.9	-26.6
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.2	2.0	3.1	4.3	5.7	8.6	12.0	12.9	12.9
			Energy Svc Charge ($M)	4.0	8.3	13.2	16.4	19.6	22.9	26.4	29.9	37.3	49.1	57.7	60.6
44,146	3.36	Nominal	**Total Resource Cost ($M)**	2,216	2,231	2,276	2,371	2,471	2,597	2,696	2,804	3,060	3,521	4,100	4,776
	0.06	Real		2,216	2,160	2,133	2,151	2,170	2,208	2,219	2,234	2,285	2,385	2,519	2,577
	2.69	Nominal	Cost in mills/kWh	48.9	49.0	49.2	50.1	51.1	52.4	53.2	54.1	57.0	62.4	68.5	77.1
	-0.59	Real		48.9	47.4	46.1	45.5	44.9	44.6	43.8	43.1	42.5	42.2	42.1	41.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.68

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 42.17

Med Load - Med Gas - Underbuild
with 25% Lower Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,967	49,794	50,165	50,896	52,009	52,856	53,885	55,025	57,147	60,601	67,094	66,797
	MWa	5,704	5,684	5,727	5,810	5,937	6,034	6,151	6,281	6,524	6,918	7,659	7,625
	Total Annual Emissions (1000 Tons)												
0.28%	CO2	51,946	49,425	49,465	50,014	51,260	51,809	53,379	53,933	54,891	56,680	58,399	54,806
0.22%	NOx	121.1	112.9	113.0	113.7	116.4	117.1	123.5	123.8	123.8	123.9	124.1	126.3
0.24%	TSP	10.9	10.1	10.1	10.2	10.3	10.4	10.8	10.9	10.9	11.0	11.0	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.24%	CO2	2,079	1,985	1,972	1,965	1,971	1,960	1,981	1,960	1,921	1,871	1,741	1,641
-1.30%	NOx	4.85	4.54	4.50	4.47	4.48	4.43	4.59	4.50	4.33	4.09	3.70	3.78
-1.28%	TSP	0.43	0.41	0.40	0.40	0.40	0.39	0.40	0.39	0.38	0.36	0.33	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	95.48	94.85	94.52	94.81	94.28	95.29	94.28	92.39	89.97	83.73	78.92
	NOx	100	93.54	92.88	92.17	92.30	91.36	94.56	92.80	89.35	84.34	76.32	77.98
	TSP	100	93.31	92.85	92.32	91.22	90.42	92.36	90.77	87.93	83.37	75.59	78.27

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,344	1,086,879
NOx	121.7	2,435
TSP	10.8	216

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Med Load - Med Gas - Underbuild with Medium Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	16.4	16.9	17.1	17.0	17.1	33.4	49.7	46.0	56.4	316.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									150.4	150.4			300.8
C	OWC Cogen 2										124.3	649.7	249.5	1023.5
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	14.3	15.7	16.1	16.4	16.9	17.1	17.0	17.1	183.8	324.4	695.7	305.9	1640.4
	DSM Programs	13.8	14.1	14.6	14.7	14.9	14.7	14.7	14.7	29.0	44.0	41.7	51.8	282.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											86.1	308.7	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									102.3				102.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT								321.2					321.2
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	13.8	14.1	14.6	14.7	14.9	14.7	14.7	335.9	131.3	44.0	127.8	360.5	1101.0
	DSM Programs	5.2	5.3	5.3	5.3	5.5	5.4	5.4	5.5	10.7	16.2	15.5	19.0	104.3
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	5.2	5.3	5.3	5.3	5.5	5.4	5.4	5.5	10.7	16.2	15.5	19.0	104.3
	DSM Programs	33.3	35.1	36.0	36.4	37.3	37.2	37.1	37.3	73.1	109.9	103.2	127.2	703.1
T	Renewable													0.0
O	Cogeneration									150.4	274.7	735.8	558.2	1719.1
T	Combined Cycle CT									102.3				102.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT								321.2					321.2
	Pumped Storage													0.0
	Total	33.3	35.1	36.0	36.4	37.3	37.2	37.1	358.5	325.8	384.6	839.0	685.4	2845.7

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(68)	(104)	(141)	(178)	(215)	(252)	(290)	(363)	(473)	(576)	(703)
T	Total Requirements	9,021	9,148	9,253	9,357	9,572	9,575	9,750	9,918	9,929	10,077	10,560	11,006
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources								321	574	849	1,584	2,143
&	Summer Purch $6/Year							112					
R	Total Resources	10,250	10,741	10,804	10,808	10,817	10,808	10,920	11,108	11,121	11,286	11,827	12,326
	Reserves	1,229	1,593	1,551	1,451	1,245	1,233	1,170	1,190	1,192	1,209	1,267	1,321
	Reserve Margin (RM) (%)	13.6	17.4	16.8	15.5	13.0	12.9	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas - Underbuild with Medium Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	23.5	24.4	24.8	24.7	25.0	48.8	71.9	65.3	79.0	450.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									160.0	160.0			320.0
C	OWC Cogen 2										132.2	691.2	265.5	1088.9
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.4**	**21.8**	**22.9**	**23.5**	**24.4**	**24.8**	**24.7**	**25.0**	**208.8**	**364.1**	**756.5**	**344.5**	**1859.4**
	DSM Programs	16.0	16.9	17.7	17.9	17.9	17.9	17.6	17.7	34.7	52.6	49.0	60.5	336.4
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											91.6	328.4	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									114.0				114.0
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT								341.7					341.7
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**16.0**	**16.9**	**17.7**	**17.9**	**17.9**	**17.9**	**17.6**	**359.4**	**148.7**	**52.6**	**140.6**	**388.9**	**1212.1**
	DSM Programs	4.7	4.9	4.9	4.9	5.0	5.0	5.0	5.1	10.3	15.8	15.4	19.7	100.7
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.7**	**4.9**	**4.9**	**4.9**	**5.0**	**5.0**	**5.0**	**5.1**	**10.3**	**15.8**	**15.4**	**19.7**	**100.7**
	DSM Programs	39.1	43.6	45.5	46.3	47.3	47.7	47.3	47.8	93.8	140.3	129.7	159.2	887.6
T	Renewable													0.0
O	Cogeneration									160.0	292.2	782.8	593.9	1828.9
T	Combined Cycle CT									114.0				114.0
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT								341.7					341.7
	Pumped Storage													0.0
	Total	**39.1**	**43.6**	**45.5**	**46.3**	**47.3**	**47.7**	**47.3**	**389.5**	**367.8**	**432.5**	**912.5**	**753.1**	**3172.2**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(83)	(128)	(175)	(222)	(270)	(317)	(365)	(458)	(599)	(728)	(888)
T	**Total Requirements**	**8,993**	**9,011**	**9,071**	**9,083**	**9,176**	**9,323**	**9,474**	**9,642**	**9,641**	**9,870**	**10,228**	**10,634**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								342	616	908	1,691	2,285
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,020**	**11,358**	**11,096**	**11,224**	**11,853**	**12,422**
	Reserves	1,355	1,839	1,949	1,959	1,850	1,696	1,546	1,715	1,455	1,353	1,625	1,788
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.6	20.2	18.2	16.3	17.8	15.1	13.7	15.9	16.8

Med Load - Med Gas - Underbuild with Medium Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	40.4	51.3	62.4	73.5	84.6	106.4	138.8	168.9	205.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1									148.9	297.9	297.9	297.9
C	OWC Cogen 2										123.1	752.1	977.6
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	9.3	19.3	29.7	40.4	51.3	62.4	73.5	84.6	255.3	559.7	1,218.9	1,481.3
	DSM Programs	10.1	20.5	31.2	42.0	52.8	63.6	74.3	85.1	106.4	138.8	169.8	208.3
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											85.1	365.9
T	Utah Combined Cycle												
A	Utah Gadsby Repower									85.6	89.3	88.3	73.5
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT								12.8	12.8	12.8	12.8	12.8
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	10.1	20.5	31.2	42.0	52.8	63.6	74.3	97.9	204.8	240.9	355.9	660.5
	DSM Programs	4.1	8.2	12.3	16.5	20.8	25.0	29.2	33.5	41.9	54.9	67.5	83.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	4.1	8.2	12.3	16.5	20.8	25.0	29.2	33.5	41.9	54.9	67.5	83.4
	DSM Programs	23.4	48.0	73.3	98.8	124.9	151.0	177.0	203.2	254.7	332.5	406.2	497.6
T	Renewable												
O	Cogeneration									148.9	420.9	1,135.1	1,641.4
T	Combined Cycle CT									85.6	89.3	88.3	73.5
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT								12.8	12.8	12.8	12.8	12.8
	Pumped Storage												
	Total	23.4	48.0	73.3	98.8	124.9	151.0	177.0	216.0	502.0	855.5	1,642.4	2,225.3
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	309.7	309.3	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	492.9	756.3	791.4	765.2	703.8	685.2	586.4	549.3	695.1	704.9	975.3	1,174.5
E	**DSM Programs**	(23.4)	(48.0)	(73.3)	(98.8)	(124.8)	(151.0)	(177.0)	(203.2)	(254.7)	(332.5)	(406.2)	(497.6)
M	**Total Requirements**	7,800.1	8,057.5	8,083.9	8,102.3	8,148.4	8,201.1	8,219.0	8,276.3	8,473.5	8,702.3	9,261.9	9,642.5
	Existing Generation	7,161.0	7,515.0	7,574.8	7,601.5	7,655.9	7,693.4	7,715.3	7,728.2	7,777.5	7,737.0	7,625.8	7,554.3
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	82.1	38.8	36.2	36.2	38.4	62.2	61.5	96.1	49.2	60.5	21.3	2.0
R	**New Resources**								12.8	247.3	523.0	1,236.1	1,727.7
	Total Resources	7,800.1	8,057.5	8,083.9	8,102.4	8,148.4	8,201.1	8,219.0	8,276.2	8,473.5	8,702.3	9,261.9	9,642.5

Case # 51

Med Load - Med Gas - Underbuild
with Medium Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	48	73	98	124	150	176	203	255	334	407	504
			After Conservation												
			System Load (MWa)	5,701	5,679	5,721	5,807	5,934	6,030	6,146	6,276	6,517	6,908	7,253	7,638
	0.52		Energy Sales (MWa)	5,152	5,159	5,218	5,309	5,410	5,515	5,623	5,732	5,899	6,139	6,463	6,613
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,285	8,472	8,674	8,850	9,149	9,500	9,859	10,483	11,567	13,203	15,142
			Net Conservation Assets ($M)	52	104	157	193	227	259	289	317	368	427	457	510
			Utility Cost												
42,966	3.31	Nominal	**Operating Revenues ($M)**	2,211	2,197	2,236	2,327	2,424	2,547	2,642	2,748	2,980	3,425	3,950	4,579
	0.01	Real		2,211	2,127	2,095	2,111	2,129	2,165	2,174	2,190	2,225	2,320	2,427	2,471
	2.77	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.0	51.1	52.7	53.6	54.7	57.7	63.7	69.8	79.0
	-0.51	Real		49.0	47.1	45.8	45.4	44.9	44.8	44.1	43.6	43.1	43.1	42.9	42.7
		Nominal	Average Customer Bill ($)	1,667	1,640	1,647	1,686	1,725	1,783	1,820	1,862	1,954	2,142	2,369	2,675
		Real		1,667	1,588	1,544	1,530	1,515	1,516	1,498	1,483	1,459	1,451	1,456	1,443
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.8	2.7	5.4	7.7	9.7	11.4	12.6	12.4	6.9	-3.6	-28.6
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.1	2.0	3.0	4.2	5.5	8.2	11.2	11.7	11.7
			Energy Svc Charge ($M)	4.6	9.4	14.5	17.7	21.0	24.4	27.9	31.5	39.0	51.0	59.3	61.8
43,415	3.30	Nominal	**Total Resource Cost ($M)**	2,216	2,207	2,251	2,346	2,447	2,574	2,674	2,785	3,027	3,487	4,021	4,652
	0.00	Real		2,216	2,136	2,109	2,128	2,149	2,188	2,201	2,219	2,260	2,362	2,471	2,510
	2.63	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.6	50.6	52.0	52.8	53.7	56.3	61.8	67.2	75.1
	-0.65	Real		48.9	46.9	45.6	45.0	44.4	44.2	43.4	42.8	42.1	41.8	41.3	40.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.03

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.47

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Med Load - Med Gas - Underbuild
with Medium Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,944	49,745	50,110	50,839	51,947	52,788	53,810	54,945	57,053	60,483	66,923	66,629
	MWa	5,701	5,679	5,720	5,804	5,930	6,026	6,143	6,272	6,513	6,905	7,640	7,606
	Total Annual Emissions (1000 Tons)												
0.22%	CO2	51,935	51,933	52,091	52,551	53,274	53,721	54,225	54,759	55,718	57,579	59,292	54,101
0.24%	NOx	121.1	121.5	121.9	122.4	123.2	123.5	126.6	126.8	126.8	127.3	127.5	126.8
0.25%	TSP	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.4	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.29%	CO2	2,080	2,088	2,079	2,067	2,051	2,035	2,015	1,993	1,953	1,904	1,772	1,624
-1.27%	NOx	4.85	4.89	4.87	4.81	4.74	4.68	4.71	4.62	4.45	4.21	3.81	3.80
-1.26%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.40	99.97	99.41	98.62	97.87	96.91	95.84	93.92	91.55	85.20	78.09
	NOx	100	100.72	100.30	99.24	97.78	96.48	97.00	95.15	91.67	86.75	78.54	78.44
	TSP	100	100.55	100.20	99.25	97.77	96.63	95.14	93.44	90.41	85.95	77.98	78.64

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,334	1,106,674
NOx	125.6	2,512
TSP	11.2	224

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Med Load - Med Gas - Underbuild with 25% Higher Non-Firm Market Prices

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	16.4	16.9	17.1	17.0	17.1	33.4	49.7	46.0	56.4	316.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									150.4	150.4			300.8
C	OWC Cogen 2									193.7	167.8	343.4	324.9	1029.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	14.3	15.7	16.1	16.4	16.9	17.1	17.0	17.1	377.5	367.9	389.4	381.3	1646.7
	DSM Programs	13.8	14.1	14.6	14.7	14.9	14.7	14.7	14.7	29.0	44.0	41.7	51.8	282.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2												233.4	233.4
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									168.0	89.5	(0.0)	(0.0)	257.5
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT								321.2					321.2
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	13.8	14.1	14.6	14.7	14.9	14.7	14.7	335.9	197.0	133.5	41.7	285.2	1094.8
	DSM Programs	5.2	5.3	5.3	5.3	5.5	5.4	5.4	5.5	10.7	16.2	15.5	19.0	104.3
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	5.2	5.3	5.3	5.3	5.5	5.4	5.4	5.5	10.7	16.2	15.5	19.0	104.3
	DSM Programs	33.3	35.1	36.0	36.4	37.3	37.2	37.1	37.3	73.1	109.9	103.2	127.2	703.1
T	Renewable													0.0
O	Cogeneration									344.1	318.2	343.4	558.3	1564.0
T	Combined Cycle CT									168.0	89.5	(0.0)	(0.0)	257.5
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT								321.2					321.2
	Pumped Storage													0.0
	Total	33.3	35.1	36.0	36.4	37.3	37.2	37.1	358.5	585.2	517.6	446.6	685.5	2845.8

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(33)	(68)	(104)	(141)	(178)	(215)	(252)	(290)	(363)	(473)	(576)	(703)
T	**Total Requirements**	9,021	9,148	9,253	9,357	9,572	9,575	9,750	9,918	9,929	10,077	10,560	11,006
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,013	9,868	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources								321	833	1,241	1,584	2,143
&	Summer Purch $6/Year							112					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,920	11,108	11,380	11,678	11,827	12,327
	Reserves	1,229	1,593	1,551	1,451	1,245	1,233	1,170	1,190	1,451	1,601	1,267	1,321
	Reserve Margin (RM) (%)	13.6	17.4	16.8	15.5	13.0	12.9	12.0	12.0	14.6	15.9	12.0	12.0

Med Load - Med Gas - Underbuild
with 25% Higher Non-Firm Market Prices

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	23.5	24.4	24.8	24.7	25.0	48.8	71.9	65.3	79.0	450.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1									160.0	160.0			320.0
C	OWC Cogen 2									206.1	178.5	365.3	345.6	1095.5
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.4**	**21.8**	**22.9**	**23.5**	**24.4**	**24.8**	**24.7**	**25.0**	**414.9**	**410.4**	**430.6**	**424.6**	**1866.0**
	DSM Programs	16.0	16.9	17.7	17.9	17.9	17.9	17.7	17.8	34.8	52.6	49.1	60.5	336.8
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2												248.3	248.3
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower									187.2	99.7	0.0	0.0	286.9
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT								341.7					341.7
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**16.0**	**16.9**	**17.7**	**17.9**	**17.9**	**17.9**	**17.7**	**359.5**	**222.0**	**152.3**	**49.1**	**308.8**	**1213.7**
	DSM Programs	4.7	4.9	4.9	4.9	5.0	5.2	5.2	5.2	10.6	16.3	15.9	20.2	103.0
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.7**	**4.9**	**4.9**	**4.9**	**5.0**	**5.2**	**5.2**	**5.2**	**10.6**	**16.3**	**15.9**	**20.2**	**103.0**
	DSM Programs	39.1	43.6	45.5	46.3	47.3	47.9	47.6	48.0	94.2	140.8	130.3	159.7	890.3
T	Renewable													0.0
O	Cogeneration									366.1	338.5	365.3	593.9	1663.8
T	Combined Cycle CT									187.2	99.7	0.0	0.0	286.9
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT								341.7					341.7
	Pumped Storage													0.0
	Total	**39.1**	**43.6**	**45.5**	**46.3**	**47.3**	**47.9**	**47.6**	**389.7**	**647.5**	**579.0**	**495.6**	**753.6**	**3182.7**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(83)	(128)	(175)	(222)	(270)	(317)	(365)	(460)	(600)	(731)	(890)
T	**Total Requirements**	**8,993**	**9,011**	**9,071**	**9,083**	**9,176**	**9,322**	**9,474**	**9,642**	**9,640**	**9,869**	**10,225**	**10,632**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,046	9,892	9,868
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								342	895	1,333	1,699	2,292
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,020**	**11,358**	**11,375**	**11,649**	**11,860**	**12,430**
	Reserves	1,355	1,839	1,949	1,959	1,850	1,696	1,546	1,716	1,735	1,780	1,635	1,798
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.6	20.2	18.2	16.3	17.8	18.0	18.0	16.0	16.9

Med Load - Med Gas - Underbuild
with 25% Higher Non-Firm Market Prices

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	40.4	51.3	62.4	73.5	84.6	106.4	138.8	168.9	205.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1									148.9	297.9	297.9	297.9
C	OWC Cogen 2									191.8	357.8	697.6	991.5
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.3**	**19.3**	**29.7**	**40.4**	**51.3**	**62.4**	**73.5**	**84.6**	**447.1**	**794.5**	**1,164.4**	**1,495.2**
	DSM Programs	10.1	20.5	31.2	42.0	52.8	63.6	74.4	85.2	106.5	138.9	169.9	208.5
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2												223.8
T	Utah Combined Cycle												
A	Utah Gadsby Repower									149.4	230.2	232.1	190.8
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT								180.9	74.8	63.7	84.8	26.7
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**10.1**	**20.5**	**31.2**	**42.0**	**52.8**	**63.6**	**74.4**	**266.1**	**330.7**	**432.8**	**486.8**	**649.8**
	DSM Programs	4.1	8.2	12.3	16.5	20.8	25.0	29.3	33.7	42.2	55.4	68.2	84.2
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**4.1**	**8.2**	**12.3**	**16.5**	**20.8**	**25.0**	**29.3**	**33.7**	**42.2**	**55.4**	**68.2**	**84.2**
	DSM Programs	23.4	48.0	73.3	98.8	124.9	151.1	177.2	203.4	255.1	333.1	407.0	498.6
T	Renewable												
O	Cogeneration									340.7	655.7	995.4	1,513.2
T	Combined Cycle CT									149.4	230.2	232.1	190.8
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT								180.9	74.8	63.7	84.8	26.7
	Pumped Storage												
	Total	**23.4**	**48.0**	**73.3**	**98.8**	**124.9**	**151.1**	**177.2**	**384.3**	**820.0**	**1,282.7**	**1,719.3**	**2,229.2**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.4	307.2	306.8	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	500.3	788.4	888.0	841.1	752.5	723.8	635.5	749.3	1,008.6	1,125.9	1,115.3	1,241.4
E	**DSM Programs**	(23.4)	(48.0)	(73.3)	(98.8)	(124.8)	(151.0)	(177.2)	(203.4)	(255.1)	(333.1)	(407.0)	(498.6)
M	**Total Requirements**	7,807.5	8,090.1	8,180.6	8,178.2	8,196.9	8,239.6	8,267.9	8,476.0	8,786.6	9,122.7	9,401.1	9,708.5
	Existing Generation	7,161.0	7,563.8	7,677.5	7,689.0	7,734.1	7,750.9	7,772.6	7,789.4	7,822.2	7,791.3	7,709.9	7,619.2
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	89.5	22.6	30.1	24.6	8.7	43.2	50.3	66.6			0.2	
R	**New Resources**							2.8	180.9	564.9	949.6	1,312.3	1,730.7
	Total Resources	7,807.5	8,090.1	8,180.6	8,178.3	8,196.9	8,239.6	8,268.0	8,476.0	8,786.6	9,122.7	9,401.1	9,708.4

Med Load - Med Gas - Underbuild
with 25% Higher Non-Firm Market Prices

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	48	73	98	124	150	177	203	256	335	408	505
			After Conservation												
			System Load (MWa)	5,701	5,679	5,721	5,807	5,934	6,030	6,146	6,275	6,517	6,907	7,253	7,637
	0.52		Energy Sales (MWa)	5,152	5,159	5,218	5,309	5,410	5,515	5,623	5,731	5,899	6,139	6,462	6,612
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,285	8,472	8,674	8,850	9,150	9,517	10,011	10,810	12,019	13,069	14,995
			Net Conservation Assets ($M)	52	104	157	193	227	260	290	320	372	430	459	511
			Utility Cost												
41,719	3.20	Nominal	**Operating Revenues ($M)**	2,211	2,167	2,205	2,295	2,394	2,516	2,616	2,719	2,896	3,320	3,850	4,365
	-0.09	Real		2,211	2,098	2,066	2,082	2,102	2,139	2,153	2,166	2,162	2,249	2,365	2,355
	2.67	Nominal	Cost in mills/kWh	49.0	48.0	48.2	49.4	50.5	52.1	53.1	54.2	56.1	61.8	68.0	75.4
	-0.61	Real		49.0	46.4	45.2	44.8	44.4	44.3	43.7	43.2	41.9	41.8	41.8	40.7
		Nominal	Average Customer Bill ($)	1,667	1,618	1,624	1,664	1,704	1,762	1,802	1,842	1,900	2,077	2,309	2,550
		Real		1,667	1,566	1,522	1,509	1,496	1,498	1,483	1,467	1,418	1,407	1,419	1,376
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.8	2.7	5.4	7.7	9.2	10.8	11.9	12.1	6.9	-3.6	-28.6
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.1	2.0	2.9	4.1	5.3	7.9	10.9	11.4	11.4
			Energy Svc Charge ($M)	4.6	9.4	14.5	17.7	21.0	24.4	27.9	31.5	39.0	51.0	59.3	61.8
42,167	3.20	Nominal	**Total Resource Cost ($M)**	2,216	2,177	2,220	2,314	2,416	2,544	2,648	2,756	2,943	3,382	3,920	4,438
	-0.10	Real		2,216	2,107	2,080	2,099	2,122	2,162	2,180	2,196	2,197	2,291	2,409	2,395
	2.53	Nominal	Cost in mills/kWh	48.9	47.8	48.0	48.9	49.9	51.4	52.3	53.2	54.8	59.9	65.5	71.6
	-0.75	Real		48.9	46.2	44.9	44.4	43.9	43.7	43.0	42.4	40.9	40.6	40.2	38.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.79**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.28**

Med Load - Med Gas - Underbuild
with 25% Higher Non-Firm Market Prices

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,944	49,749	50,110	50,839	51,945	52,787	53,809	54,943	57,049	60,478	66,915	66,625
	MWa	5,701	5,679	5,720	5,804	5,930	6,026	6,143	6,272	6,512	6,904	7,639	7,606
	Total Annual Emissions (1000 Tons)												
0.17%	CO2	51,935	52,224	52,352	52,763	53,491	53,882	54,384	54,917	55,686	57,422	59,184	53,670
0.22%	NOx	121.1	122.5	122.7	123.0	123.9	124.0	127.2	127.4	126.7	126.6	127.0	126.4
0.25%	TSP	10.9	11.0	11.0	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.33%	CO2	2,080	2,100	2,089	2,076	2,060	2,041	2,021	1,999	1,952	1,899	1,769	1,611
-1.29%	NOx	4.85	4.92	4.90	4.84	4.77	4.70	4.73	4.64	4.44	4.19	3.80	3.79
-1.26%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.42	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.95	100.47	99.81	99.03	98.16	97.20	96.12	93.87	91.31	85.06	77.47
	NOx	100	101.52	100.93	99.74	98.30	96.86	97.44	95.58	91.57	86.32	78.28	78.20
	TSP	100	101.53	100.98	99.86	98.41	97.10	95.58	93.87	90.42	85.77	77.92	78.66

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,310	1,106,205
NOx	125.6	2,513
TSP	11.2	224

Page 179

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Med Load - Med Gas
Test of Transmission Plant Conversion

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	20.7	21.2	21.3	21.3	21.4	41.8	62.5	58.9	73.2	388.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4					150.4
C	OWC Cogen 2									82.5	67.9			150.4
	OWC Combined Cycle											150.4		150.4
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L												146.0	146.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	14.3	15.7	16.1	20.7	21.2	21.3	21.3	171.8	124.3	130.4	209.3	219.2	985.6
	DSM Programs	13.4	13.9	14.6	14.7	15.3	15.3	15.1	15.2	30.0	45.4	43.2	53.8	289.9
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1										36.7			36.7
U	Utah Cogen 2										150.4			150.4
T	Utah Combined Cycle											150.4		150.4
A	Utah Gadsby Repower								140.3	157.0	(0.0)			297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											207.4	192.6	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage											123.0	77.0	200.0
	Total	13.4	13.9	14.6	14.7	15.3	15.3	15.1	155.5	187.0	232.5	524.0	323.4	1524.7
	DSM Programs	4.5	5.1	5.3	6.5	6.5	6.6	6.5	6.6	12.9	19.6	18.8	23.6	122.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle											84.7		84.7
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												264.0	264.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.5	5.1	5.3	6.5	6.5	6.6	6.5	6.6	12.9	19.6	103.5	287.6	471.2
	DSM Programs	32.2	34.7	36.0	41.9	43.0	43.2	42.9	43.2	84.7	127.5	120.9	150.6	800.8
T	Renewable													0.0
O	Cogeneration								150.4	82.5	255.0			487.9
T	Combined Cycle CT								140.3	157.0	(0.0)	385.5		682.8
A	Coal & IGCC											207.4	456.6	664.0
L	Transmission												146.0	146.0
	Simple Cycle CT													0.0
	Pumped Storage											123.0	77.0	200.0
	Total	32.2	34.7	36.0	41.9	43.0	43.2	42.9	333.9	324.2	382.5	836.8	830.2	2981.5

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(32)	(67)	(103)	(145)	(188)	(231)	(274)	(317)	(402)	(529)	(650)	(801)
T	Total Requirements	9,022	9,149	9,254	9,353	9,562	9,559	9,728	9,891	9,890	10,021	10,486	10,908
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,696
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources								291	530	785	1,501	2,181
&	Summer Purch $6/Year							88					
R	Total Resources	10,250	10,741	10,804	10,808	10,817	10,808	10,896	11,078	11,077	11,223	11,744	12,218
	Reserves	1,228	1,592	1,550	1,455	1,255	1,249	1,168	1,187	1,187	1,203	1,258	1,310
	Reserve Margin (RM) (%)	13.6	17.4	16.7	15.6	13.1	13.1	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
Test of Transmission Plant Conversion

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	27.0	27.8	28.3	28.1	28.5	55.6	82.3	75.7	92.7	509.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0					160.0
C	OWC Cogen 2									87.7	72.3			160.0
	OWC Combined Cycle											160.0		160.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L												146.0	146.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.4**	**21.8**	**22.9**	**27.0**	**27.8**	**28.3**	**28.1**	**188.5**	**143.3**	**154.6**	**235.7**	**238.7**	**1135.1**
	DSM Programs	15.7	16.6	17.7	17.8	18.4	18.2	18.0	18.1	35.4	53.4	49.8	61.5	340.6
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1										39.0			39.0
U	Utah Cogen 2										160.0			160.0
T	Utah Combined Cycle											160.0		160.0
A	Utah Gadsby Repower								156.3	175.0	(0.1)			331.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4											207.4	192.6	400.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage											123.0	77.0	200.0
	Total	**15.7**	**16.6**	**17.7**	**17.8**	**18.4**	**18.2**	**18.0**	**174.4**	**210.4**	**252.3**	**540.2**	**331.1**	**1630.8**
	DSM Programs	4.0	4.7	4.9	5.5	5.6	5.6	5.6	5.6	11.1	16.7	15.8	19.7	104.8
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle											90.1		90.1
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2												264.0	264.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.0**	**4.7**	**4.9**	**5.5**	**5.6**	**5.6**	**5.6**	**5.6**	**11.1**	**16.7**	**105.9**	**283.7**	**458.9**
	DSM Programs	38.1	43.1	45.5	50.3	51.8	52.1	51.7	52.2	102.1	152.4	141.3	173.9	954.5
T	Renewable													0.0
O	Cogeneration								160.0	87.7	271.3			519.0
T	Combined Cycle CT								156.3	175.0	(0.1)	410.1		741.3
A	Coal & IGCC											207.4	456.6	664.0
L	Transmission												146.0	146.0
	Simple Cycle CT													0.0
	Pumped Storage											123.0	77.0	200.0
	Total	**38.1**	**43.1**	**45.5**	**50.3**	**51.8**	**52.1**	**51.7**	**368.5**	**364.8**	**423.6**	**881.8**	**853.5**	**3224.8**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(38)	(81)	(127)	(177)	(229)	(281)	(333)	(385)	(487)	(639)	(781)	(955)
T	**Total Requirements**	**8,994**	**9,013**	**9,072**	**9,080**	**9,169**	**9,311**	**9,458**	**9,622**	**9,612**	**9,830**	**10,175**	**10,568**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,721
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources								316	579	850	1,591	2,270
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,850	11,020	11,041	11,026	11,018	11,020	11,332	11,059	11,166	11,753	12,260
	Reserves	1,354	1,837	1,948	1,961	1,857	1,707	1,562	1,710	1,447	1,337	1,577	1,693
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.6	20.3	18.3	16.5	17.8	15.1	13.6	15.5	16.0

Med Load - Med Gas
Test of Transmission Plant Conversion

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	42.4	55.4	68.6	81.7	94.9	120.7	159.3	195.6	240.7
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	148.9	148.9	148.9	148.9
C	OWC Cogen 2									81.6	148.9	148.9	148.9
	OWC Combined Cycle											132.2	148.9
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												128.0
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.3**	**19.3**	**29.7**	**42.4**	**55.4**	**68.6**	**81.7**	**243.8**	**351.3**	**457.1**	**625.6**	**815.3**
	DSM Programs	9.8	19.9	30.6	41.3	52.4	63.5	74.5	85.5	107.2	140.3	171.8	211.2
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1										36.3	36.3	36.3
U	Utah Cogen 2										145.6	143.3	139.1
T	Utah Combined Cycle											94.4	89.0
A	Utah Gadsby Repower								114.2	232.5	232.6	228.0	213.2
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4											190.0	366.6
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage											20.7	33.2
	Total	**9.8**	**19.9**	**30.6**	**41.3**	**52.4**	**63.5**	**74.5**	**199.7**	**339.7**	**554.8**	**884.5**	**1,088.5**
	DSM Programs	3.3	7.3	11.5	16.2	20.9	25.7	30.4	35.1	44.5	58.7	72.4	89.6
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle											53.8	52.3
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												241.9
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**7.3**	**11.5**	**16.2**	**20.9**	**25.7**	**30.4**	**35.1**	**44.5**	**58.7**	**126.2**	**383.8**
	DSM Programs	22.4	46.5	71.8	99.9	128.7	157.7	186.6	215.5	272.5	358.3	439.9	541.4
T	Renewable												
O	Cogeneration								148.9	230.6	479.7	477.4	473.2
T	Combined Cycle CT								114.2	232.5	232.6	508.4	503.3
A	Coal & IGCC											190.0	608.5
L	Transmission												128.0
	Simple Cycle CT												
	Pumped Storage											20.7	33.2
	Total	**22.4**	**46.5**	**71.8**	**99.9**	**128.7**	**157.7**	**186.6**	**478.7**	**735.5**	**1,070.6**	**1,636.4**	**2,287.6**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.1	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	331.6	347.6
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	503.9	755.3	791.0	754.8	710.0	689.2	607.5	749.0	889.6	886.3	959.1	1,143.6
E	**DSM Programs**	(22.4)	(46.5)	(71.8)	(99.9)	(128.7)	(157.7)	(186.5)	(215.5)	(272.5)	(358.3)	(439.9)	(541.4)
M	**Total Requirements**	7,812.1	8,058.4	8,085.4	8,090.8	8,150.7	8,198.4	8,230.6	8,463.6	8,650.3	8,857.9	9,238.6	9,610.3
	Existing Generation	7,161.1	7,515.6	7,576.0	7,601.8	7,656.0	7,692.8	7,715.3	7,745.5	7,785.2	7,739.1	7,640.7	7,473.3
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	94.0	39.1	36.5	24.3	40.7	60.1	73.1	15.8	2.6	24.7	22.7	32.3
R	**New Resources**								263.2	463.0	712.3	1,196.5	1,746.2
	Total Resources	7,812.1	8,058.4	8,085.4	8,090.8	8,150.7	8,198.4	8,230.6	8,463.5	8,650.3	8,857.9	9,238.6	9,610.3

Med Load - Med Gas

Test of Transmission Plant Conversion

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	22	47	72	100	129	158	187	217	275	362	444	552
			After Conservation												
			System Load (MWa)	5,702	5,680	5,722	5,805	5,929	6,022	6,135	6,262	6,498	6,880	7,217	7,591
	0.51		Energy Sales (MWa)	5,153	5,160	5,219	5,307	5,406	5,508	5,613	5,719	5,882	6,114	6,430	6,570
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,286	8,475	8,685	8,877	9,251	9,699	10,022	10,607	11,804	13,733	16,250
			Net Conservation Assets ($M)	52	105	160	203	245	285	323	359	424	498	539	599
			Utility Cost												
41,877	3.16	Nominal	**Operating Revenues ($M)**	2,211	2,197	2,237	2,327	2,424	2,547	2,640	2,678	2,913	3,331	3,825	4,376
	-0.13	Real		2,211	2,127	2,096	2,111	2,129	2,165	2,173	2,134	2,175	2,256	2,351	2,361
	2.65	Nominal	Cost in mills/kWh	49.0	48.6	48.9	50.1	51.2	52.8	53.7	53.5	56.5	62.2	67.9	76.0
	-0.63	Real		49.0	47.1	45.9	45.4	45.0	44.9	44.2	42.6	42.2	42.1	41.7	41.0
		Nominal	Average Customer Bill ($)	1,667	1,641	1,648	1,687	1,725	1,783	1,818	1,814	1,910	2,083	2,294	2,556
		Real		1,667	1,588	1,544	1,530	1,515	1,516	1,497	1,445	1,426	1,411	1,410	1,379
			Total Resource Cost												
			DSR Customer Cost ($M)	0.6	1.5	2.5	5.8	9.0	11.8	14.4	16.7	19.3	18.1	12.5	-5.0
			Levelized (20-year at 8.6%)	0.1	0.2	0.5	1.1	2.1	3.3	4.9	6.6	10.6	16.7	21.4	23.0
			Energy Svc Charge ($M)	4.3	9.1	14.2	18.0	22.0	26.1	30.4	34.7	43.9	58.6	70.0	75.7
42,426	3.16	Nominal	**Total Resource Cost ($M)**	2,216	2,207	2,251	2,346	2,448	2,576	2,675	2,719	2,967	3,406	3,917	4,474
	-0.14	Real		2,216	2,136	2,110	2,128	2,150	2,190	2,202	2,167	2,215	2,307	2,407	2,414
	2.49	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.6	50.6	52.0	52.8	52.5	55.2	60.3	65.4	72.2
	-0.79	Real		48.9	46.9	45.6	45.0	44.4	44.2	43.5	41.8	41.2	40.9	40.2	39.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.12

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 40.53

Med Load - Med Gas

Test of Transmission Plant Conversion

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,953	49,761	50,126	50,829	51,913	52,729	53,727	54,836	56,898	60,257	66,912	66,454
	MWa	5,702	5,680	5,722	5,802	5,926	6,019	6,133	6,260	6,495	6,879	7,638	7,586
	Total Annual Emissions (1000 Tons)												
0.07%	CO2	51,939	51,940	52,099	52,548	53,260	53,694	54,188	54,582	55,437	57,193	59,949	52,663
0.10%	NOx	121.1	121.5	121.9	122.4	123.2	123.5	126.6	126.2	125.9	126.1	130.2	123.4
0.41%	TSP	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.4	11.7
	Annual System Emission Rates (Pounds/MWh)												
-1.42%	CO2	2,080	2,088	2,079	2,068	2,052	2,037	2,017	1,991	1,949	1,898	1,792	1,585
-1.40%	NOx	4.85	4.88	4.86	4.81	4.75	4.68	4.71	4.60	4.43	4.19	3.89	3.71
-1.09%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.35
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.39	99.96	99.43	98.67	97.94	97.00	95.73	93.71	91.29	86.17	76.22
	NOx	100	100.71	100.29	99.28	97.86	96.60	97.16	94.92	91.27	86.30	80.25	76.57
	TSP	100	100.54	100.19	99.29	97.85	96.74	95.29	93.53	90.43	85.84	78.51	81.27

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,160	1,103,193
NOx	125.3	2,507
TSP	11.2	225

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Med Load - Med Gas
with Added Transmission Bridger to OWC

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	13.8	15.3	15.9	16.4	16.8	17.0	17.0	17.1	33.5	49.6	46.2	56.5	315.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2									16.7	192.6	598.4	433.1	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**13.8**	**15.3**	**15.9**	**16.4**	**16.8**	**17.0**	**17.0**	**167.5**	**200.6**	**242.2**	**644.6**	**489.6**	**1856.7**
	DSM Programs	11.4	12.5	14.3	14.4	14.5	14.5	14.3	14.4	28.4	43.0	40.8	51.0	273.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2									46.2	83.5	138.8	126.3	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							13.5	168.0	40.3				221.8
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**11.4**	**12.5**	**14.3**	**14.4**	**14.5**	**14.5**	**27.8**	**182.4**	**114.9**	**126.5**	**179.6**	**177.3**	**890.1**
	DSM Programs	4.5	4.5	5.2	5.2	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.7	100.6
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.5**	**4.5**	**5.2**	**5.2**	**5.3**	**5.3**	**5.3**	**5.3**	**10.4**	**15.9**	**15.0**	**18.7**	**100.6**
	DSM Programs	29.7	32.3	35.4	36.0	36.6	36.8	36.6	36.8	72.3	108.5	102.0	126.2	689.2
T	Renewable													0.0
O	Cogeneration								150.4	213.3	276.1	737.2	559.4	1936.4
T	Combined Cycle CT							13.5	168.0	40.3				221.8
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**29.7**	**32.3**	**35.4**	**36.0**	**36.6**	**36.8**	**50.1**	**355.2**	**325.9**	**384.6**	**839.2**	**685.6**	**2847.4**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(30)	(62)	(97)	(133)	(170)	(207)	(243)	(280)	(353)	(461)	(563)	(689)
T	Total Requirements	9,024	9,154	9,260	9,365	9,580	9,583	9,759	9,928	9,940	10,089	10,573	11,020
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,207	10,122	10,013	9,868	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							14	332	586	862	1,599	2,158
&	Summer Purch $6/Year							109					
R	Total Resources	10,250	10,741	10,804	10,808	10,817	10,808	10,930	11,118	11,132	11,299	11,841	12,343
	Reserves	1,226	1,587	1,544	1,443	1,237	1,225	1,172	1,191	1,192	1,210	1,268	1,323
	Reserve Margin (RM) (%)	13.6	17.3	16.7	15.4	12.9	12.8	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with Added Transmission Bridger to OWC

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	17.2	21.1	22.3	23.3	24.1	24.5	24.5	24.9	48.7	71.9	65.7	79.5	447.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2									17.8	204.9	636.6	460.7	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**17.2**	**21.1**	**22.3**	**23.3**	**24.1**	**24.5**	**24.5**	**184.9**	**226.5**	**276.8**	**702.3**	**540.2**	**2087.7**
	DSM Programs	13.8	15.3	17.4	17.5	17.7	17.5	17.3	17.3	34.1	51.3	47.7	59.1	326.0
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2									49.1	88.9	147.6	134.4	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							15.0	187.2	45.0				247.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**15.3**	**17.4**	**17.5**	**17.7**	**17.5**	**32.3**	**204.5**	**128.2**	**140.2**	**195.3**	**193.5**	**993.2**
	DSM Programs	4.0	4.1	4.8	4.7	4.9	4.9	4.9	4.9	9.7	14.6	13.7	16.9	92.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.0**	**4.1**	**4.8**	**4.7**	**4.9**	**4.9**	**4.9**	**4.9**	**9.7**	**14.6**	**13.7**	**16.9**	**92.1**
	DSM Programs	35.0	40.5	44.5	45.5	46.7	46.9	46.7	47.1	92.5	137.8	127.1	155.5	865.8
T	Renewable													0.0
O	Cogeneration								160.0	226.9	293.8	784.2	595.1	2060.0
T	Combined Cycle CT							15.0	187.2	45.0				247.2
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**35.0**	**40.5**	**44.5**	**45.5**	**46.7**	**46.9**	**61.7**	**394.3**	**364.4**	**431.6**	**911.3**	**750.6**	**3173.0**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(35)	(76)	(120)	(166)	(212)	(259)	(306)	(353)	(445)	(583)	(710)	(866)
T	**Total Requirements**	**8,997**	**9,019**	**9,079**	**9,092**	**9,186**	**9,333**	**9,485**	**9,654**	**9,654**	**9,886**	**10,246**	**10,656**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,254	10,161	10,046	9,892	9,868
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							15	362	634	928	1,712	2,307
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,035**	**11,378**	**11,114**	**11,243**	**11,873**	**12,445**
	Reserves	1,351	1,832	1,941	1,950	1,840	1,685	1,549	1,724	1,461	1,357	1,628	1,788
	Reserve Margin (RM) (%)	15.0	20.3	21.4	21.4	20.0	18.0	16.3	17.9	15.1	13.7	15.9	16.8

Med Load - Med Gas
with Added Transmission Bridger to OWC

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	8.7	18.5	28.6	39.1	49.9	60.9	71.9	83.0	104.7	137.1	167.4	204.5
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2									16.5	207.2	766.3	1,094.9
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**8.7**	**18.5**	**28.6**	**39.1**	**49.9**	**60.9**	**71.9**	**231.9**	**419.1**	**642.2**	**1,231.6**	**1,597.2**
	DSM Programs	8.1	16.9	27.3	37.7	48.3	58.8	69.2	79.7	100.3	131.7	161.5	199.0
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2									45.7	128.4	265.8	373.0
T	Utah Combined Cycle												
A	Utah Gadsby Repower							13.1	162.8	196.2	199.2	157.7	114.2
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**8.1**	**16.9**	**27.3**	**37.7**	**48.3**	**58.8**	**82.3**	**242.5**	**342.2**	**459.2**	**585.0**	**686.2**
	DSM Programs	3.3	6.7	10.7	14.8	18.9	23.0	27.1	31.2	39.3	51.6	63.3	78.0
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**6.7**	**10.7**	**14.8**	**18.9**	**23.0**	**27.1**	**31.2**	**39.3**	**51.6**	**63.3**	**78.0**
	DSM Programs	20.2	42.1	66.6	91.6	117.1	142.7	168.2	193.8	244.3	320.4	392.2	481.4
T	Renewable												
O	Cogeneration								148.9	360.1	633.5	1,330.0	1,765.7
T	Combined Cycle CT							13.1	162.8	196.2	199.2	157.7	114.2
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**20.2**	**42.1**	**66.6**	**91.6**	**117.1**	**142.7**	**181.3**	**505.6**	**800.6**	**1,153.0**	**1,879.9**	**2,361.4**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.4	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	542.4	800.3	836.4	815.7	737.8	707.1	635.7	822.4	954.0	962.0	1,147.6	1,244.1
E	**DSM Programs**	(20.2)	(42.1)	(66.6)	(91.6)	(117.1)	(142.6)	(168.2)	(193.8)	(244.3)	(320.4)	(392.2)	(481.4)
M	**Total Requirements**	7,852.8	8,107.9	8,135.6	8,160.0	8,190.2	8,231.4	8,277.2	8,558.7	8,742.8	8,971.5	9,448.1	9,728.3
	Existing Generation	7,201.9	7,565.5	7,632.5	7,656.4	7,705.6	7,737.7	7,755.2	7,789.1	7,787.0	7,748.4	7,581.8	7,489.8
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	93.8	38.7	30.2	39.0	30.6	48.2	66.7	18.7		8.8		
R	**New Resources**							13.1	311.8	556.3	832.6	1,487.7	1,880.0
	Total Resources	7,852.8	8,107.9	8,135.6	8,160.1	8,190.2	8,231.4	8,277.2	8,558.7	8,742.8	8,971.5	9,448.1	9,728.2

Med Load - Med Gas
with Added Transmission Bridger to OWC

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	20	42	66	91	117	142	168	194	245	322	393	487
			After Conservation												
			System Load (MWa)	5,704	5,685	5,728	5,814	5,941	6,038	6,155	6,285	6,528	6,920	7,268	7,655
	0.52		Energy Sales (MWa)	5,155	5,164	5,224	5,315	5,417	5,523	5,631	5,740	5,909	6,151	6,476	6,629
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,048	8,327	8,582	8,995	9,187	9,578	10,041	10,391	10,999	11,980	13,617	15,486
			Net Conservation Assets ($M)	45	92	144	180	214	246	277	305	356	412	440	485
			Utility Cost												
43,039	3.29	Nominal	**Operating Revenues ($M)**	2,211	2,194	2,247	2,353	2,480	2,603	2,692	2,717	2,992	3,423	3,941	4,582
	-0.01	Real		2,211	2,124	2,105	2,134	2,178	2,213	2,216	2,165	2,234	2,318	2,422	2,472
	2.75	Nominal	Cost in mills/kWh	49.0	48.5	49.1	50.5	52.3	53.8	54.6	54.0	57.8	63.5	69.5	78.9
	-0.53	Real		49.0	47.0	46.0	45.8	45.9	45.7	44.9	43.1	43.2	43.0	42.7	42.6
		Nominal	Average Customer Bill ($)	1,667	1,638	1,655	1,705	1,765	1,822	1,854	1,841	1,963	2,140	2,364	2,677
		Real		1,667	1,586	1,551	1,547	1,550	1,549	1,526	1,466	1,465	1,450	1,452	1,444
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.7	5.0	7.2	9.1	10.7	11.9	12.2	7.1	-3.3	-28.3
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.1	1.9	2.8	4.0	5.2	7.8	10.8	11.4	11.4
			Energy Svc Charge ($M)	3.9	8.1	13.1	16.2	19.4	22.8	26.2	29.7	37.1	48.9	57.6	60.6
43,469	3.29	Nominal	**Total Resource Cost ($M)**	2,215	2,202	2,260	2,370	2,501	2,628	2,722	2,752	3,037	3,482	4,010	4,654
	-0.01	Real		2,215	2,132	2,118	2,150	2,196	2,234	2,240	2,193	2,267	2,359	2,464	2,511
	2.62	Nominal	Cost in mills/kWh	48.9	48.3	48.8	50.1	51.7	53.1	53.7	53.1	56.5	61.7	67.0	75.1
	-0.66	Real		48.9	46.8	45.8	45.5	45.4	45.1	44.2	42.3	42.2	41.8	41.2	40.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.03

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.52

Med Load - Med Gas
with Added Transmission Bridger to OWC

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,972	49,801	50,169	50,902	52,016	52,861	53,888	55,027	57,144	60,590	67,064	66,752
	MWa	5,705	5,685	5,727	5,811	5,938	6,034	6,152	6,282	6,523	6,917	7,656	7,620
	Total Annual Emissions (1000 Tons)												
0.11%	CO2	52,194	52,258	52,452	52,911	53,602	54,024	54,464	54,795	55,725	57,511	59,189	53,321
0.17%	NOx	122.0	122.5	123.0	123.5	124.2	124.4	127.3	126.6	126.6	126.7	126.8	126.1
0.20%	TSP	11.0	11.0	11.0	11.1	11.2	11.2	11.2	11.2	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.40%	CO2	2,089	2,099	2,091	2,079	2,061	2,044	2,021	1,992	1,950	1,898	1,765	1,598
-1.34%	NOx	4.88	4.92	4.90	4.85	4.78	4.71	4.72	4.60	4.43	4.18	3.78	3.78
-1.31%	TSP	0.44	0.44	0.44	0.44	0.43	0.42	0.42	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.47	100.10	99.52	98.66	97.85	96.77	95.34	93.37	90.88	84.50	76.48
	NOx	100	100.82	100.48	99.40	97.84	96.45	96.77	94.28	90.77	85.71	77.48	77.38
	TSP	100	100.69	100.44	99.46	97.86	96.61	94.93	92.96	89.72	85.05	77.06	77.80

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,320	1,106,409
NOx	125.6	2,513
TSP	11.2	225

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Med Load - Med Gas
with Added Transmission Utah to OWC

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.1	15.4	16.1	16.4	16.8	17.1	16.9	17.1	33.4	49.6	46.1	56.5	315.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2									62.6	276.3	517.7	384.2	1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.1**	**15.4**	**16.1**	**16.4**	**16.8**	**17.1**	**16.9**	**167.5**	**246.4**	**325.9**	**563.8**	**440.7**	**1857.1**
	DSM Programs	11.4	12.5	14.3	14.4	14.5	14.5	14.3	14.4	28.4	43.0	40.8	51.0	273.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											219.5	175.3	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							13.4	168.0	40.7				222.1
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**11.4**	**12.5**	**14.3**	**14.4**	**14.5**	**14.5**	**27.7**	**182.4**	**69.1**	**43.0**	**260.3**	**226.3**	**890.4**
	DSM Programs	4.5	4.5	4.6	5.2	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.7	100.0
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.5**	**4.5**	**4.6**	**5.2**	**5.3**	**5.3**	**5.3**	**5.3**	**10.4**	**15.9**	**15.0**	**18.7**	**100.0**
	DSM Programs	30.0	32.4	35.0	36.0	36.6	36.9	36.5	36.8	72.2	108.5	101.9	126.2	689.0
T	Renewable													0.0
O	Cogeneration								150.4	213.0	276.3	737.2	559.5	1936.4
T	Combined Cycle CT							13.4	168.0	40.7				222.1
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**30.0**	**32.4**	**35.0**	**36.0**	**36.6**	**36.9**	**49.9**	**355.2**	**325.9**	**384.8**	**839.1**	**685.7**	**2847.5**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(30)	(62)	(97)	(133)	(170)	(207)	(243)	(280)	(352)	(461)	(563)	(689)
T	**Total Requirements**	**9,024**	**9,154**	**9,260**	**9,365**	**9,580**	**9,583**	**9,759**	**9,928**	**9,940**	**10,089**	**10,573**	**11,020**
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,207	10,123	10,014	9,869	9,844
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							13	332	586	862	1,599	2,159
&	Summer Purch $6/Year							109					
R	**Total Resources**	**10,250**	**10,741**	**10,804**	**10,808**	**10,817**	**10,808**	**10,930**	**11,118**	**11,132**	**11,299**	**11,842**	**12,343**
	Reserves	1,226	1,587	1,544	1,443	1,237	1,225	1,171	1,190	1,192	1,210	1,268	1,323
	Reserve Margin (RM) (%)	13.6	17.3	16.7	15.4	12.9	12.8	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with Added Transmission Utah to OWC

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.0	21.3	22.6	23.3	24.2	24.4	24.5	24.9	48.6	71.8	65.5	79.2	448.3
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2									66.6	293.9	550.7	408.8	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.0**	**21.3**	**22.6**	**23.3**	**24.2**	**24.4**	**24.5**	**184.9**	**275.2**	**365.7**	**616.2**	**488.0**	**2088.3**
	DSM Programs	13.8	15.3	17.4	17.5	17.7	17.5	17.3	17.3	34.1	51.3	47.7	59.1	326.0
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											233.6	186.4	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							15.0	187.2	45.3				247.5
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**15.3**	**17.4**	**17.5**	**17.7**	**17.5**	**32.3**	**204.5**	**79.4**	**51.3**	**281.3**	**245.5**	**993.5**
	DSM Programs	4.0	4.1	4.1	4.8	4.9	4.9	4.9	4.9	9.7	14.6	13.7	16.9	91.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.0**	**4.1**	**4.1**	**4.8**	**4.9**	**4.9**	**4.9**	**4.9**	**9.7**	**14.6**	**13.7**	**16.9**	**91.5**
	DSM Programs	35.8	40.7	44.1	45.6	46.8	46.8	46.7	47.1	92.4	137.7	126.9	155.2	865.8
T	Renewable													0.0
O	Cogeneration								160.0	226.6	293.9	784.3	595.2	2060.0
T	Combined Cycle CT							15.0	187.2	45.3				247.5
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**35.8**	**40.7**	**44.1**	**45.6**	**46.8**	**46.8**	**61.7**	**394.3**	**364.3**	**431.6**	**911.2**	**750.4**	**3173.3**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(36)	(77)	(121)	(166)	(213)	(260)	(307)	(354)	(446)	(584)	(711)	(866)
T	**Total Requirements**	**8,996**	**9,018**	**9,078**	**9,091**	**9,185**	**9,332**	**9,485**	**9,653**	**9,653**	**9,885**	**10,245**	**10,656**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,254	10,162	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							15	362	634	928	1,712	2,308
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,035**	**11,378**	**11,115**	**11,244**	**11,874**	**12,445**
	Reserves	1,352	1,833	1,942	1,950	1,841	1,686	1,550	1,724	1,462	1,358	1,628	1,789
	Reserve Margin (RM) (%)	15.0	20.3	21.4	21.5	20.0	18.1	16.3	17.9	15.1	13.7	15.9	16.8

Med Load - Med Gas
with Added Transmission Utah to OWC

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.0	18.8	29.1	39.6	50.4	61.4	72.4	83.5	105.2	137.6	167.7	204.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2									62.0	335.4	819.9	1,100.7
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.0**	**18.8**	**29.1**	**39.6**	**50.4**	**61.4**	**72.4**	**232.4**	**465.1**	**770.8**	**1,285.5**	**1,603.4**
	DSM Programs	8.1	16.9	27.3	37.7	48.3	58.8	69.2	79.7	100.3	131.7	161.5	199.0
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											212.3	367.2
T	Utah Combined Cycle												
A	Utah Gadsby Repower							11.2	144.9	182.8	188.8	155.9	114.6
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**8.1**	**16.9**	**27.3**	**37.7**	**48.3**	**58.8**	**80.4**	**224.5**	**283.1**	**320.4**	**529.8**	**680.8**
	DSM Programs	3.3	6.7	10.1	14.2	18.3	22.4	26.5	30.6	38.7	51.0	62.7	77.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**6.7**	**10.1**	**14.2**	**18.3**	**22.4**	**26.5**	**30.6**	**38.7**	**51.0**	**62.7**	**77.4**
	DSM Programs	20.5	42.4	66.5	91.5	117.0	142.5	168.1	193.7	244.2	320.2	392.0	481.1
T	Renewable												
O	Cogeneration								148.9	359.9	633.3	1,330.1	1,765.8
T	Combined Cycle CT							11.2	144.9	182.8	188.8	155.9	114.6
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**20.5**	**42.4**	**66.5**	**91.5**	**117.0**	**142.5**	**179.3**	**487.5**	**786.8**	**1,142.2**	**1,878.0**	**2,361.5**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	501.1	758.6	807.4	782.8	719.6	685.1	598.2	771.7	925.6	946.8	1,146.2	1,244.3
E	**DSM Programs**	(20.5)	(42.4)	(66.5)	(91.5)	(117.0)	(142.5)	(168.1)	(193.7)	(244.2)	(320.2)	(392.0)	(481.1)
M	**Total Requirements**	7,811.2	8,065.9	8,107.2	8,127.3	8,172.1	8,209.5	8,239.7	8,508.1	8,714.5	8,956.5	9,446.9	9,728.8
	Existing Generation	7,165.9	7,527.8	7,594.8	7,620.8	7,671.8	7,701.5	7,719.2	7,747.6	7,768.0	7,740.4	7,582.3	7,489.8
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	88.3	34.4	39.5	41.8	46.2	62.4	67.1	27.6	4.4	12.4		
R	**New Resources**							11.2	293.8	542.6	822.0	1,486.0	1,880.4
	Total Resources	7,811.2	8,065.9	8,107.1	8,127.3	8,172.1	8,209.5	8,239.8	8,508.1	8,714.5	8,956.5	9,446.9	9,728.7

Med Load - Med Gas

with Added Transmission Utah to OWC

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	20	42	66	91	116	142	168	193	245	322	393	487
			After Conservation												
			System Load (MWa)	5,704	5,685	5,728	5,814	5,942	6,038	6,155	6,285	6,528	6,920	7,268	7,655
	0.52		Energy Sales (MWa)	5,155	5,164	5,225	5,315	5,417	5,523	5,631	5,740	5,909	6,151	6,476	6,629
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,048	8,328	8,581	8,994	9,187	9,578	10,040	10,387	10,989	11,955	13,613	15,495
			Net Conservation Assets ($M)	46	93	144	180	213	246	276	305	356	412	440	485
			Utility Cost												
43,060	3.29	Nominal	**Operating Revenues ($M)**	2,211	2,194	2,247	2,353	2,481	2,603	2,694	2,724	2,997	3,429	3,940	4,582
	-0.01	Real		2,211	2,124	2,106	2,134	2,178	2,213	2,217	2,170	2,238	2,323	2,421	2,472
	2.75	Nominal	Cost in mills/kWh	49.0	48.5	49.1	50.5	52.3	53.8	54.6	54.2	57.9	63.6	69.5	78.9
	-0.53	Real		49.0	47.0	46.0	45.8	45.9	45.8	44.9	43.2	43.2	43.1	42.7	42.6
		Nominal	Average Customer Bill ($)	1,667	1,638	1,656	1,705	1,765	1,823	1,855	1,845	1,966	2,145	2,363	2,676
		Real		1,667	1,586	1,552	1,547	1,550	1,550	1,527	1,470	1,468	1,453	1,452	1,444
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.6	5.0	7.2	9.0	10.7	11.9	12.2	7.1	-3.3	-28.3
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.1	1.9	2.8	3.9	5.2	7.8	10.8	11.4	11.4
			Energy Svc Charge ($M)	3.9	8.2	13.0	16.1	19.4	22.7	26.1	29.7	37.1	48.9	57.5	60.6
43,490	3.29	Nominal	**Total Resource Cost ($M)**	2,215	2,203	2,261	2,370	2,502	2,629	2,724	2,758	3,042	3,489	4,009	4,653
	-0.01	Real		2,215	2,132	2,119	2,150	2,197	2,235	2,242	2,198	2,271	2,363	2,463	2,511
	2.62	Nominal	Cost in mills/kWh	48.9	48.3	48.8	50.1	51.7	53.1	53.8	53.2	56.6	61.8	66.9	75.1
	-0.66	Real		48.9	46.8	45.8	45.5	45.4	45.1	44.2	42.4	42.3	41.9	41.1	40.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.05

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.54

Med Load - Med Gas
with Added Transmission Utah to OWC

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,970	49,798	50,173	50,903	52,016	52,862	53,888	55,028	57,145	60,591	67,067	66,753
	MWa	5,704	5,685	5,728	5,811	5,938	6,034	6,152	6,282	6,523	6,917	7,656	7,620
	Total Annual Emissions (1000 Tons)												
0.13%	CO2	51,975	52,026	52,235	52,704	53,412	53,808	54,256	54,615	55,617	57,478	59,176	53,319
0.21%	NOx	121.2	121.8	122.3	122.8	123.6	123.7	126.6	126.0	126.2	126.6	126.8	126.1
0.24%	TSP	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.1	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.38%	CO2	2,080	2,090	2,082	2,071	2,054	2,036	2,014	1,985	1,947	1,897	1,765	1,598
-1.31%	NOx	4.85	4.89	4.88	4.82	4.75	4.68	4.70	4.58	4.42	4.18	3.78	3.78
-1.27%	TSP	0.44	0.44	0.44	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.45	100.09	99.54	98.72	97.86	96.80	95.42	93.57	91.20	84.83	76.79
	NOx	100	100.79	100.47	99.43	97.91	96.46	96.81	94.39	91.05	86.15	77.91	77.85
	TSP	100	100.65	100.43	99.50	97.95	96.63	94.97	93.08	90.06	85.57	77.58	78.37

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,211	1,104,229
NOx	125.3	2,505
TSP	11.2	224

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Med Load - Med Gas
with Renewables at 35% of Capital Cost

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	12.9	15.4	15.8	16.2	16.6	16.8	16.7	16.8	32.9	48.8	45.2	55.6	309.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								16.3	200.3	31.1	53.1		300.8
C	OWC Cogen 2											667.7	228.2	895.9
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage			100.0	100.0									200.0
	Total	12.9	15.4	115.8	116.2	16.6	16.8	16.7	33.1	233.2	79.9	766.0	283.8	1706.4
	DSM Programs	11.4	12.5	13.4	14.4	14.5	14.5	14.3	14.4	28.4	43.1	40.7	51.0	272.6
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal									53.9	246.1			300.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											17.3	299.7	317.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								119.7				32.6	152.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	11.4	12.5	13.4	14.4	14.5	14.5	14.3	134.1	82.3	289.2	58.0	383.3	1041.9
	DSM Programs	4.5	4.5	4.6	5.2	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.7	100.0
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.5	4.5	4.6	5.2	5.3	5.3	5.3	5.3	10.4	15.9	15.0	18.7	100.0
	DSM Programs	28.8	32.4	33.8	35.8	36.4	36.6	36.3	36.5	71.7	107.8	100.9	125.3	682.3
T	Renewable									53.9	246.1			300.0
O	Cogeneration								16.3	200.3	31.1	738.1	527.9	1513.7
T	Combined Cycle CT								119.7				32.6	152.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage			100.0	100.0									200.0
	Total	28.8	32.4	133.8	135.8	36.4	36.6	36.3	172.5	325.9	385.0	839.0	685.8	2848.3

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(29)	(61)	(95)	(131)	(167)	(204)	(240)	(277)	(348)	(456)	(557)	(682)
T	**Total Requirements**	9,025	9,155	9,262	9,367	9,583	9,586	9,762	9,931	9,944	10,094	10,579	11,027
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources			100	200	200	200	200	336	590	867	1,606	2,166
&	Summer Purch $6/Year												
R	**Total Resources**	10,250	10,741	10,904	11,008	11,017	11,008	11,008	11,123	11,137	11,305	11,848	12,350
	Reserves	1,225	1,586	1,642	1,641	1,434	1,422	1,246	1,191	1,157	1,011	1,069	1,124
	Reserve Margin (RM) (%)	13.6	17.3	17.7	17.5	15.0	14.8	12.8	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with Renewables at 35% of Capital Cost

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.3	21.2	22.3	22.9	23.6	24.0	23.9	24.2	47.1	69.2	62.9	76.3	433.9
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								17.3	213.1	33.1	56.5		320.0
C	OWC Cogen 2											710.3	242.8	953.1
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage			100.0	100.0									200.0
	Total	**16.3**	**21.2**	**122.3**	**122.9**	**23.6**	**24.0**	**23.9**	**41.5**	**260.2**	**102.3**	**829.7**	**319.1**	**1907.0**
	DSM Programs	13.8	15.3	16.5	17.5	17.7	17.5	17.3	17.4	34.0	51.3	47.8	59.1	325.2
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal									53.9	246.1			300.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											18.4	318.8	337.2
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower								133.3				36.4	169.7
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.8**	**15.3**	**16.5**	**17.5**	**17.7**	**17.5**	**17.3**	**150.7**	**87.9**	**297.4**	**66.2**	**414.3**	**1132.1**
	DSM Programs	4.0	4.1	4.1	4.8	4.9	4.9	4.9	4.9	9.7	14.6	13.7	16.9	91.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.0	4.1	4.1	4.8	4.9	4.9	4.9	4.9	9.7	14.6	13.7	16.9	91.5
	DSM Programs	34.1	40.6	42.9	45.2	46.2	46.4	46.1	46.5	90.8	135.1	124.4	152.3	850.6
T	Renewable									53.9	246.1			300.0
O	Cogeneration								17.3	213.1	33.1	785.2	561.6	1610.3
T	Combined Cycle CT								133.3				36.4	169.7
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage			100.0	100.0									200.0
	Total	**34.1**	**40.6**	**142.9**	**145.2**	**46.2**	**46.4**	**46.1**	**197.1**	**357.8**	**414.3**	**909.6**	**750.3**	**3130.6**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(34)	(75)	(118)	(163)	(209)	(255)	(302)	(348)	(439)	(574)	(698)	(851)
T	**Total Requirements**	**8,998**	**9,019**	**9,081**	**9,094**	**9,189**	**9,337**	**9,490**	**9,659**	**9,660**	**9,895**	**10,258**	**10,671**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,162	10,047	9,893	9,868
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources			100	200	200	200	200	351	618	897	1,682	2,280
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,120**	**11,241**	**11,226**	**11,218**	**11,220**	**11,366**	**11,098**	**11,212**	**11,844**	**12,417**
	Reserves	1,350	1,831	2,039	2,147	2,037	1,881	1,731	1,707	1,402	1,117	1,386	1,546
	Reserve Margin (RM) (%)	15.0	20.3	22.5	23.6	22.2	20.1	18.2	17.7	14.9	13.3	15.5	16.4

Med Load - Med Gas with Renewables at 35% of Capital Cost

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	8.0	17.7	27.8	38.1	48.6	59.3	69.9	80.6	101.6	132.6	161.4	196.9
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								16.1	214.5	245.2	297.9	297.9
C	OWC Cogen 2											629.5	788.8
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage			99.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0
	Total	**8.0**	**17.7**	**126.8**	**236.1**	**246.6**	**257.3**	**267.9**	**294.8**	**514.0**	**575.8**	**1,286.8**	**1,481.6**
	DSM Programs	8.1	16.9	26.4	36.9	47.4	57.9	68.3	78.8	99.4	130.8	160.7	198.1
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal									51.1	284.4	284.4	284.4
	Utah Cogen 1												
U	Utah Cogen 2											16.0	278.8
T	Utah Combined Cycle												
A	Utah Gadsby Repower								99.2	98.9	100.1	81.6	69.0
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**8.1**	**16.9**	**26.4**	**36.9**	**47.4**	**57.9**	**68.3**	**178.0**	**249.4**	**515.3**	**542.7**	**830.4**
	DSM Programs	3.3	6.7	10.1	14.2	18.3	22.4	26.5	30.6	38.7	51.0	62.7	77.4
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**6.7**	**10.1**	**14.2**	**18.3**	**22.4**	**26.5**	**30.6**	**38.7**	**51.0**	**62.7**	**77.4**
	DSM Programs	19.4	41.3	64.3	89.1	114.3	139.6	164.7	190.0	239.7	314.4	384.8	472.4
T	Renewable									51.1	284.4	284.4	284.4
O	Cogeneration								16.1	214.5	245.2	943.4	1,365.5
T	Combined Cycle CT								99.2	98.9	100.1	81.6	69.0
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage			99.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0
	Total	**19.4**	**41.3**	**163.3**	**287.1**	**312.3**	**337.6**	**362.7**	**503.3**	**802.1**	**1,142.1**	**1,892.3**	**2,389.4**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	306.8	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	498.6	753.3	862.7	910.9	839.7	808.8	734.8	793.4	912.1	899.8	1,121.7	1,242.0
E	**DSM Programs**	(19.4)	(41.3)	(64.3)	(89.1)	(114.3)	(139.6)	(164.7)	(190.0)	(239.7)	(314.4)	(384.9)	(472.4)
M	**Total Requirements**	7,809.7	8,061.6	8,164.6	8,257.7	8,294.7	8,336.1	8,379.7	8,533.5	8,705.6	8,915.4	9,429.6	9,735.1
	Existing Generation	7,161.2	7,516.5	7,561.3	7,583.7	7,636.0	7,665.3	7,700.7	7,739.4	7,738.8	7,685.9	7,543.5	7,459.6
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	91.5	41.4	31.4	11.4	6.7	27.3	38.8	41.7	4.8	20.0		
R	**New Resources**			99.0	198.0	198.0	198.0	198.0	313.3	562.4	827.7	1,507.4	1,917.0
	Total Resources	7,809.8	8,061.6	8,164.6	8,257.8	8,294.7	8,336.1	8,379.7	8,533.5	8,705.6	8,915.4	9,429.5	9,735.1

Med Load - Med Gas
with Renewables at 35% of Capital Cost

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	19	41	64	88	113	138	162	187	237	310	379	469
			After Conservation												
			System Load (MWa)	5,705	5,686	5,730	5,817	5,945	6,043	6,161	6,291	6,536	6,932	7,282	7,673
	0.53		Energy Sales (MWa)	5,156	5,165	5,226	5,318	5,421	5,527	5,636	5,746	5,917	6,161	6,489	6,645
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,128	8,417	8,650	8,847	9,014	9,268	9,568	9,926	10,550	11,531	13,174	15,087
			Net Conservation Assets ($M)	44	91	140	175	207	238	267	295	343	396	421	463
			Utility Cost												
42,277	3.26	Nominal	**Operating Revenues ($M)**	2,212	2,198	2,223	2,314	2,423	2,541	2,623	2,676	2,924	3,362	3,863	4,480
	-0.04	Real		2,212	2,127	2,084	2,100	2,128	2,160	2,158	2,132	2,183	2,277	2,374	2,417
	2.72	Nominal	Cost in mills/kWh	49.0	48.6	48.6	49.7	51.0	52.5	53.1	53.2	56.4	62.3	68.0	77.0
	-0.56	Real		49.0	47.0	45.5	45.1	44.8	44.6	43.7	42.4	42.1	42.2	41.8	41.5
		Nominal	Average Customer Bill ($)	1,668	1,641	1,638	1,677	1,724	1,779	1,807	1,813	1,918	2,103	2,317	2,617
		Real		1,668	1,588	1,535	1,522	1,514	1,512	1,487	1,444	1,432	1,424	1,424	1,412
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.5	5.2	7.5	9.5	11.1	12.2	12.4	7.1	-3.9	-29.5
			Levelized (20-year at 8.6%)	0.1	0.3	0.5	1.1	1.9	2.9	4.1	5.4	8.0	11.0	11.5	11.5
			Energy Svc Charge ($M)	3.7	8.0	12.5	15.6	18.8	22.0	25.4	28.8	36.0	47.5	56.1	59.1
42,698	3.26	Nominal	**Total Resource Cost ($M)**	2,216	2,206	2,236	2,331	2,443	2,566	2,652	2,710	2,968	3,421	3,931	4,550
	-0.04	Real		2,216	2,135	2,096	2,115	2,146	2,181	2,183	2,159	2,216	2,317	2,415	2,455
	2.58	Nominal	Cost in mills/kWh	48.9	48.4	48.3	49.3	50.5	51.8	52.3	52.3	55.2	60.6	65.6	73.4
	-0.69	Real		48.9	46.9	45.3	44.7	44.3	44.1	43.1	41.7	41.2	41.0	40.3	39.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.19

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 40.79

Med Load - Med Gas
with Renewables at 35% of Capital Cost

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,979	49,807	50,193	50,924	52,038	52,888	53,918	55,060	57,185	60,643	67,143	66,830
	MWa	5,705	5,686	5,730	5,813	5,940	6,037	6,155	6,285	6,528	6,923	7,665	7,629
	Total Annual Emissions (1000 Tons)												
0.13%	CO2	51,952	51,965	51,696	51,728	52,472	52,986	53,498	53,931	54,719	55,548	57,297	53,260
0.20%	NOx	121.1	121.5	121.7	122.0	122.9	123.4	126.5	126.2	126.4	126.2	126.5	125.9
0.20%	TSP	10.9	10.9	10.9	10.9	11.0	11.1	11.1	11.1	11.2	11.2	11.2	11.3
	Annual System Emission Rates (Pounds/MWh)												
-1.39%	CO2	2,079	2,087	2,060	2,032	2,017	2,004	1,984	1,959	1,914	1,832	1,707	1,594
-1.32%	NOx	4.85	4.88	4.85	4.79	4.72	4.67	4.69	4.58	4.42	4.16	3.77	3.77
-1.32%	TSP	0.43	0.44	0.43	0.43	0.42	0.42	0.41	0.40	0.39	0.37	0.33	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.37	99.09	97.72	97.00	96.38	95.45	94.23	92.06	88.12	82.10	76.67
	NOx	100	100.68	100.05	98.80	97.41	96.29	96.76	94.57	91.17	85.87	77.73	77.70
	TSP	100	100.52	99.88	98.67	97.27	96.36	94.86	93.08	89.87	84.86	77.02	77.73

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,216	1,084,325
NOx	125.0	2,500
TSP	11.1	223

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Med Load - Med Gas
with Extension of all Existing Firm Wholesale Contracts

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.1	15.6	16.1	16.4	16.8	17.0	17.0	17.1	33.4	49.6	46.1	56.5	315.7
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2								197.6	176.1	380.0	487.1		1240.8
	OWC Combined Cycle												500.8	500.8
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage												146.5	146.5
	Total	**14.1**	**15.6**	**16.1**	**16.4**	**16.8**	**17.0**	**17.0**	**365.1**	**359.9**	**429.6**	**533.2**	**703.8**	**2504.6**
	DSM Programs	13.4	13.9	14.6	14.7	14.8	14.8	14.7	14.7	29.0	44.0	41.7	51.8	282.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1											30.4	6.3	36.7
U	Utah Cogen 2									48.6	235.9	110.3		394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							57.3	168.0	72.0				297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage											138.1	61.9	200.0
	Total	**13.4**	**13.9**	**14.6**	**14.7**	**14.8**	**14.8**	**72.0**	**182.7**	**149.6**	**279.9**	**320.5**	**120.0**	**1210.9**
	DSM Programs	4.5	5.1	6.3	6.5	6.5	6.6	6.5	6.6	12.9	19.6	18.8	23.6	123.5
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.5**	**5.1**	**6.3**	**6.5**	**6.5**	**6.6**	**6.5**	**6.6**	**12.9**	**19.6**	**18.8**	**23.6**	**123.5**
	DSM Programs	32.0	34.6	37.0	37.6	38.1	38.4	38.2	38.4	75.3	113.2	106.6	131.9	721.3
T	Renewable													0.0
O	Cogeneration								348.0	375.1	615.9	627.8	6.3	1973.1
T	Combined Cycle CT							57.3	168.0	72.0			500.8	798.1
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage											138.1	208.4	346.5
	Total	**32.0**	**34.6**	**37.0**	**37.6**	**38.1**	**38.4**	**95.5**	**554.4**	**522.4**	**729.1**	**872.5**	**847.4**	**3839.0**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	2,115	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130
S	DSM Programs	(32)	(67)	(104)	(141)	(179)	(218)	(256)	(294)	(370)	(483)	(589)	(721)
T	**Total Requirements**	9,022	9,149	9,253	9,597	9,811	9,907	10,081	10,249	10,567	11,020	11,575	12,191
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,207	10,207	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	758	738	732	725	718	697	692	692	692	692
L	New Resources							57	573	1,020	1,636	2,402	3,118
&	Summer Purch $6/Year					72	170	308					
R	Total Resources	10,250	10,741	10,904	10,908	10,989	11,096	11,291	11,477	11,835	12,342	12,963	13,653
	Reserves	1,228	1,592	1,651	1,311	1,178	1,189	1,210	1,229	1,268	1,322	1,389	1,462
	Reserve Margin (RM) (%)	13.6	17.4	17.8	13.7	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with Extension of all Existing Firm Wholesale Contracts

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.0	21.5	22.6	23.3	24.1	24.5	24.5	24.8	48.7	71.8	65.4	79.3	448.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2								210.2	187.4	404.2	518.2		1320.0
	OWC Combined Cycle												532.8	532.8
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage												146.5	146.5
	Total	**18.0**	**21.5**	**22.6**	**23.3**	**24.1**	**24.5**	**24.5**	**395.0**	**396.1**	**476.0**	**583.6**	**758.6**	**2767.8**
	DSM Programs	15.7	16.6	17.7	17.8	18.0	17.9	17.6	17.6	34.7	52.3	48.7	60.0	334.6
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1											32.4	6.6	39.0
U	Utah Cogen 2									51.7	250.9	117.4		420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							63.8	187.2	80.2				331.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage											138.1	61.9	200.0
	Total	15.7	16.6	17.7	17.8	18.0	**17.9**	**81.4**	**204.8**	**166.6**	**303.2**	**336.6**	**128.5**	**1324.8**
	DSM Programs	4.0	4.7	5.3	5.5	5.6	5.6	5.6	5.6	11.1	16.8	15.8	19.7	105.3
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.0	4.7	5.3	5.5	5.6	**5.6**	**5.6**	**5.6**	**11.1**	**16.8**	**15.8**	19.7	105.3
	DSM Programs	37.7	42.8	45.6	46.6	47.7	48.0	47.7	48.0	94.5	140.9	129.9	159.0	888.4
T	Renewable													0.0
O	Cogeneration								370.2	399.1	655.1	668.0	6.6	2099.0
T	Combined Cycle CT							63.8	187.2	80.2			532.8	864.0
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage											138.1	208.4	346.5
	Total	**37.7**	**42.8**	**45.6**	**46.6**	**47.7**	**48.0**	**111.5**	**605.4**	**573.8**	**796.0**	**936.0**	**906.8**	**4197.9**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463
S	DSM Programs	(38)	(81)	(126)	(173)	(220)	(268)	(316)	(364)	(459)	(600)	(729)	(888)
T	**Total Requirements**	**8,994**	**9,014**	**9,073**	**9,184**	**9,328**	**9,474**	**9,625**	**9,793**	**10,108**	**10,596**	**11,078**	**11,660**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	905	1,010	1,004	979	972	967	959	954	954	954	954
L	New Resources							64	621	1,101	1,756	2,562	3,310
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,930**	**11,200**	**11,221**	**11,206**	**11,216**	**11,282**	**11,835**	**12,216**	**12,757**	**13,409**	**14,133**
	Reserves	1,354	1,917	2,127	2,037	1,878	1,742	1,657	2,042	2,107	2,161	2,331	2,473
	Reserve Margin (RM) (%)	15.1	21.3	23.4	22.2	20.1	18.4	17.2	20.9	20.9	20.4	21.0	21.2

Med Load - Med Gas
with Extension of all Existing Firm Wholesale Contracts

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.0	19.0	29.2	39.8	50.6	61.6	72.6	83.6	105.4	137.7	167.9	205.0
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2								195.6	369.9	700.3	1,108.4	1,169.0
	OWC Combined Cycle												233.4
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.0**	**19.0**	**29.2**	**39.8**	**50.6**	**61.6**	**72.6**	**428.2**	**773.2**	**1,135.9**	**1,574.2**	**1,905.2**
	DSM Programs	9.8	19.9	30.6	41.3	52.2	63.0	73.7	84.5	105.8	138.1	168.9	207.2
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1											30.2	36.3
U	Utah Cogen 2									47.9	275.3	355.8	379.0
T	Utah Combined Cycle												
A	Utah Gadsby Repower							48.0	176.7	202.2	171.6	134.0	179.5
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage											12.1	11.8
	Total	**9.8**	**19.9**	**30.6**	**41.3**	**52.2**	**63.0**	**121.7**	**261.2**	**355.8**	**584.9**	**701.0**	**813.8**
	DSM Programs	3.3	7.3	11.9	16.5	21.3	26.0	30.8	35.5	44.9	59.1	72.8	90.0
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**3.3**	**7.3**	**11.9**	**16.5**	**21.3**	**26.0**	**30.8**	**35.5**	**44.9**	**59.1**	**72.8**	**90.0**
	DSM Programs	22.1	46.2	71.7	97.6	124.1	150.6	177.1	203.7	256.0	334.9	409.6	502.2
T	Renewable												
O	Cogeneration								344.5	715.6	1,273.4	1,792.2	1,882.2
T	Combined Cycle CT							48.0	176.7	202.2	171.6	134.0	412.9
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage											12.1	11.8
	Total	**22.1**	**46.2**	**71.7**	**97.6**	**124.1**	**150.6**	**225.0**	**724.8**	**1,173.8**	**1,779.9**	**2,347.9**	**2,809.0**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.7	307.2	307.0	307.0	307.0	306.7	305.0	305.0	320.6	320.2
S	**Firm Sales**	1,605.8	1,622.6	1,622.4	1,676.7	1,682.6	1,682.6	1,682.6	1,682.6	1,682.6	1,682.6	1,682.6	1,682.6
T	**Non-Firm Sales**	516.7	761.3	796.9	728.5	647.6	644.3	618.9	855.2	970.7	1,012.4	1,036.2	1,039.6
E	**DSM Programs**	(22.1)	(46.2)	(71.7)	(97.6)	(124.1)	(150.6)	(177.1)	(203.7)	(256.0)	(334.9)	(409.6)	(502.2)
M	**Total Requirements**	7,825.2	8,064.8	8,141.5	8,210.0	8,261.1	8,353.4	8,444.2	8,809.3	9,165.0	9,597.2	9,980.4	10,372.4
	Existing Generation	7,155.3	7,511.7	7,557.5	7,610.0	7,664.1	7,704.4	7,735.5	7,745.5	7,723.7	7,628.5	7,518.6	7,542.1
L	**Firm Purchases**	557.0	536.0	553.2	545.0	538.1	533.0	529.7	526.5	523.4	523.4	523.4	523.4
&	**Non-Firm Purchases**	112.9	17.2	30.9	55.0	58.9	116.1	131.2	16.1		0.2		
R	**New Resources**							48.0	521.2	917.8	1,445.0	1,938.4	2,306.9
	Total Resources	7,825.2	8,064.8	8,141.5	8,210.0	8,261.1	8,353.4	8,444.3	8,809.3	9,165.0	9,597.2	9,980.4	10,372.4

Med Load - Med Gas

with Extension of all Existing Firm Wholesale Contracts

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	22	46	71	97	124	150	177	203	257	336	410	508
			After Conservation												
			System Load (MWa)	5,702	5,681	5,723	5,808	5,934	6,030	6,146	6,275	6,516	6,906	7,250	7,634
	0.52		Energy Sales (MWa)	5,153	5,160	5,220	5,310	5,411	5,515	5,623	5,731	5,898	6,137	6,460	6,609
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,082	8,281	8,470	8,677	8,906	9,418	10,012	10,454	11,193	12,578	14,203	16,097
			Net Conservation Assets ($M)	49	100	155	192	227	261	292	322	374	432	460	508
			Utility Cost												
42,273	3.16	Nominal	**Operating Revenues ($M)**	2,211	2,206	2,273	2,338	2,437	2,563	2,643	2,672	2,937	3,316	3,920	4,438
	-0.14	Real		2,211	2,136	2,130	2,121	2,140	2,179	2,175	2,129	2,193	2,246	2,408	2,395
	2.63	Nominal	Cost in mills/kWh	49.0	48.8	49.7	50.3	51.4	53.1	53.7	53.2	56.8	61.7	69.3	76.7
	-0.65	Real		49.0	47.3	46.6	45.6	45.2	45.1	44.2	42.4	42.4	41.8	42.6	41.4
		Nominal	Average Customer Bill ($)	1,667	1,647	1,675	1,695	1,735	1,795	1,820	1,810	1,926	2,074	2,351	2,592
		Real		1,667	1,595	1,569	1,537	1,523	1,526	1,498	1,442	1,438	1,405	1,444	1,399
			Total Resource Cost												
			DSR Customer Cost ($M)	1.0	2.0	3.1	5.6	8.0	10.1	12.0	13.4	14.3	10.1	0.9	-22.4
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.2	2.1	3.2	4.4	5.9	8.9	12.7	14.1	14.1
			Energy Svc Charge ($M)	4.3	9.0	14.4	17.7	21.1	24.7	28.3	32.1	40.0	52.5	61.7	64.6
42,744	3.16	Nominal	**Total Resource Cost ($M)**	2,216	2,216	2,288	2,357	2,460	2,591	2,676	2,710	2,986	3,381	3,995	4,516
	-0.14	Real		2,216	2,145	2,144	2,138	2,161	2,203	2,202	2,159	2,229	2,290	2,455	2,437
	2.48	Nominal	Cost in mills/kWh	48.9	48.6	49.4	49.8	50.8	52.3	52.8	52.3	55.6	59.9	66.7	72.9
	-0.79	Real		48.9	47.1	46.3	45.2	44.7	44.5	43.5	41.7	41.5	40.6	41.0	39.3

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 42.35

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 40.83

Med Load - Med Gas

with Extension of all Existing Firm Wholesale Contracts

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,956	49,765	50,126	50,850	51,954	52,792	53,811	54,938	57,042	60,463	67,016	66,709
	MWa	5,703	5,681	5,722	5,805	5,931	6,027	6,143	6,271	6,512	6,902	7,650	7,615
	Total Annual Emissions (1000 Tons)												
-0.05%	CO2	51,906	51,792	52,045	52,593	53,337	53,770	54,194	54,513	55,413	57,233	59,084	51,438
0.24%	NOx	121.0	121.4	121.7	122.5	123.4	123.8	127.0	126.3	126.3	126.6	127.3	126.7
0.27%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.2	11.1	11.2	11.2	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-1.56%	CO2	2,078	2,081	2,077	2,069	2,053	2,037	2,014	1,985	1,943	1,893	1,763	1,542
-1.27%	NOx	4.85	4.88	4.86	4.82	4.75	4.69	4.72	4.60	4.43	4.19	3.80	3.80
-1.25%	TSP	0.43	0.44	0.44	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.16	99.93	99.54	98.81	98.03	96.93	95.50	93.50	91.10	84.85	74.21
	NOx	100	100.72	100.25	99.42	98.08	96.77	97.42	94.91	91.38	86.43	78.39	78.39
	TSP	100	100.55	100.17	99.50	98.16	97.01	95.39	93.41	90.25	85.54	77.81	78.81

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,851	1,097,027
NOx	125.4	2,508
TSP	11.2	224

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Med Load - Med Gas
with Extension of Loads & DSM to 2045

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	12.0	14.0	14.6	15.3	16.6	16.9	16.7	17.1	33.4	58.0	58.9	74.7	348.2
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2								7.5	46.3	263.1	539.4	284.7	1141.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**12.0**	**14.0**	**14.6**	**15.3**	**16.6**	**16.9**	**16.7**	**175.0**	**230.1**	**321.1**	**598.3**	**359.4**	**1790.0**
	DSM Programs	8.9	11.8	12.2	12.3	13.2	13.1	14.4	14.3	29.0	44.0	50.2	70.3	293.7
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											168.4	226.4	394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							30.0	168.0	55.9	0.0			253.9
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**8.9**	**11.8**	**12.2**	**12.3**	**13.2**	**13.1**	**44.4**	**182.3**	**84.9**	**44.0**	**218.6**	**296.7**	**942.4**
	DSM Programs	2.7	3.6	4.4	4.7	4.6	4.7	5.3	5.3	10.8	18.4	18.9	24.0	107.4
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**2.7**	**3.6**	**4.4**	**4.7**	**4.6**	**4.7**	**5.3**	**5.3**	**10.8**	**18.4**	**18.9**	**24.0**	**107.4**
	DSM Programs	23.6	29.4	31.2	32.3	34.4	34.7	36.4	36.7	73.2	120.4	128.0	169.0	749.3
T	Renewable													0.0
O	Cogeneration								157.9	196.7	263.1	707.8	511.1	1836.6
T	Combined Cycle CT							30.0	168.0	55.9	0.0			253.9
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**23.6**	**29.4**	**31.2**	**32.3**	**34.4**	**34.7**	**66.4**	**362.6**	**325.8**	**383.5**	**835.8**	**680.1**	**2839.8**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(24)	(53)	(84)	(117)	(151)	(186)	(222)	(259)	(332)	(452)	(580)	(749)
T	**Total Requirements**	9,030	9,163	9,273	9,382	9,599	9,604	9,780	9,949	9,960	10,098	10,556	10,960
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,207	10,123	10,014	9,869	9,844
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources							30	356	609	872	1,579	2,091
&	Summer Purch $6/Year							116					
R	**Total Resources**	10,250	10,741	10,804	10,808	10,817	10,808	10,954	11,142	11,155	11,309	11,822	12,275
	Reserves	1,220	1,578	1,531	1,427	1,218	1,204	1,174	1,193	1,195	1,212	1,266	1,316
	Reserve Margin (RM) (%)	13.5	17.2	16.5	15.2	12.7	12.5	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with Extension of Loads & DSM to 2045

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	16.4	20.1	21.2	22.0	24.0	24.2	24.2	24.8	48.5	78.5	75.8	94.8	474.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2								8.0	49.2	279.9	573.9	302.8	1213.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**16.4**	**20.1**	**21.2**	**22.0**	**24.0**	**24.2**	**24.2**	**192.8**	**257.7**	**358.4**	**649.7**	**397.6**	**2008.3**
	DSM Programs	11.5	14.7	15.4	15.6	16.4	16.2	17.3	17.3	34.7	52.2	55.4	74.9	341.6
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1													0.0
U	Utah Cogen 2											179.1	240.9	420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							33.4	187.2	62.3				282.9
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**11.5**	**14.7**	**15.4**	**15.6**	**16.4**	**16.2**	**50.7**	**204.5**	**97.0**	**52.2**	**234.5**	**315.8**	**1044.5**
	DSM Programs	2.4	3.2	4.1	4.2	4.2	4.3	4.9	4.9	10.0	16.2	15.8	20.2	94.4
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**2.4**	**3.2**	**4.1**	**4.2**	**4.2**	**4.3**	**4.9**	**4.9**	**10.0**	**16.2**	**15.8**	**20.2**	**94.4**
	DSM Programs	30.3	38.0	40.7	41.8	44.6	44.7	46.4	47.0	93.2	146.9	147.0	189.9	910.5
T	Renewable													0.0
O	Cogeneration								168.0	209.2	279.9	753.0	543.7	1953.8
T	Combined Cycle CT							33.4	187.2	62.3				282.9
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**30.3**	**38.0**	**40.7**	**41.8**	**44.6**	**44.7**	**79.8**	**402.2**	**364.7**	**426.8**	**900.0**	**733.6**	**3147.2**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(30)	(68)	(109)	(151)	(195)	(240)	(287)	(334)	(427)	(574)	(721)	(911)
T	**Total Requirements**	**9,002**	**9,026**	**9,090**	**9,106**	**9,203**	**9,352**	**9,505**	**9,674**	**9,672**	**9,895**	**10,235**	**10,612**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,254	10,162	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources							33	389	660	940	1,693	2,237
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,020**	**11,041**	**11,026**	**11,018**	**11,053**	**11,404**	**11,141**	**11,256**	**11,855**	**12,374**
	Reserves	1,346	1,824	1,930	1,935	1,823	1,666	1,549	1,731	1,469	1,360	1,619	1,763
	Reserve Margin (RM) (%)	15.0	20.2	21.2	21.3	19.8	17.8	16.3	17.9	15.2	13.7	15.8	16.6

Med Load - Med Gas
with Extension of Loads & DSM to 2045

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	7.6	16.4	25.5	35.0	45.6	56.4	67.2	78.2	99.9	136.2	172.6	218.6
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal												
W	OWC Cogen 1								148.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2								7.4	53.3	313.7	824.3	1,030.5
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**7.6**	**16.4**	**25.5**	**35.0**	**45.6**	**56.4**	**67.2**	**234.6**	**451.0**	**747.8**	**1,294.8**	**1,547.0**
	DSM Programs	6.2	14.6	23.2	32.0	41.2	50.4	60.8	71.3	92.5	124.8	159.9	207.9
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												
	Utah Cogen 1												
U	Utah Cogen 2											163.4	368.0
T	Utah Combined Cycle												
A	Utah Gadsby Repower							25.0	154.5	204.9	216.2	182.2	140.0
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**6.2**	**14.6**	**23.2**	**32.0**	**41.2**	**50.4**	**85.8**	**225.7**	**297.4**	**341.0**	**505.4**	**715.9**
	DSM Programs	2.1	4.7	8.0	11.5	15.0	18.5	22.6	26.7	35.0	48.7	62.4	80.0
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**2.1**	**4.7**	**8.0**	**11.5**	**15.0**	**18.5**	**22.6**	**26.7**	**35.0**	**48.7**	**62.4**	**80.0**
	DSM Programs	15.9	35.6	56.7	78.4	101.8	125.2	150.5	176.1	227.4	309.7	394.9	506.5
T	Renewable												
O	Cogeneration								156.4	351.1	611.6	1,285.5	1,696.4
T	Combined Cycle CT							25.0	154.5	204.9	216.2	182.2	140.0
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**15.9**	**35.6**	**56.7**	**78.4**	**101.8**	**125.2**	**175.5**	**486.9**	**783.4**	**1,137.5**	**1,862.6**	**2,342.9**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	310.2	309.8	307.2	307.0	307.0	307.0	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**	487.0	749.9	791.5	757.9	696.3	662.2	600.8	774.0	930.5	945.4	1,144.4	1,243.2
E	**DSM Programs**	(15.9)	(35.6)	(56.7)	(78.4)	(101.8)	(125.2)	(150.5)	(176.1)	(227.4)	(309.7)	(394.9)	(506.5)
M	**Total Requirements**	7,801.7	8,064.0	8,101.0	8,115.4	8,164.0	8,203.9	8,259.8	8,528.0	8,736.3	8,965.6	9,442.2	9,702.2
	Existing Generation	7,161.5	7,517.1	7,582.1	7,607.5	7,661.8	7,699.8	7,726.3	7,750.9	7,776.3	7,747.6	7,595.9	7,507.3
L	**Firm Purchases**	557.0	503.7	472.9	464.7	454.1	445.5	442.3	439.1	399.5	381.7	378.6	358.5
&	**Non-Firm Purchases**	83.2	43.1	46.0	43.2	48.1	58.6	66.3	27.2	4.4	8.5		
R	**New Resources**							25.0	310.8	556.0	827.8	1,467.8	1,836.4
	Total Resources	7,801.7	8,064.0	8,101.0	8,115.5	8,164.0	8,203.9	8,259.9	8,528.0	8,736.3	8,965.6	9,442.2	9,702.2

Med Load - Med Gas
with Extension of Loads & DSM to 2045

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	16	36	57	78	101	125	150	176	228	314	400	515
			After Conservation												
			System Load (MWa)	5,708	5,691	5,738	5,827	5,957	6,055	6,172	6,302	6,545	6,928	7,260	7,627
	1.67		Energy Sales (MWa)	5,159	5,170	5,233	5,327	5,431	5,539	5,647	5,757	5,925	6,158	6,470	6,604
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,070	8,261	8,441	8,641	8,842	9,247	9,716	10,065	10,672	11,648	13,309	15,195
			Net Conservation Assets ($M)	38	80	126	158	190	221	253	283	339	424	503	606
			Utility Cost												
45,026	4.17	Nominal	**Operating Revenues ($M)**	2,212	2,198	2,237	2,328	2,426	2,549	2,635	2,669	2,939	3,368	3,876	4,505
	0.84	Real		2,212	2,128	2,097	2,112	2,130	2,167	2,169	2,127	2,194	2,281	2,381	2,431
	2.46	Nominal	Cost in mills/kWh	49.0	48.5	48.8	49.9	51.0	52.5	53.3	52.9	56.6	62.4	68.4	77.9
	-0.81	Real		49.0	47.0	45.7	45.3	44.8	44.7	43.8	42.2	42.3	42.3	42.0	42.0
		Nominal	Average Customer Bill ($)	1,668	1,641	1,649	1,687	1,726	1,785	1,815	1,808	1,928	2,106	2,324	2,632
		Real		1,668	1,589	1,545	1,531	1,516	1,517	1,494	1,441	1,439	1,427	1,428	1,420
			Total Resource Cost												
			DSR Customer Cost ($M)	0.7	1.4	2.0	4.2	5.7	7.1	8.5	9.6	9.8	7.3	2.9	-12.3
			Levelized (20-year at 8.6%)	0.1	0.2	0.4	0.9	1.5	2.2	3.1	4.2	6.3	9.1	10.6	10.6
			Energy Svc Charge ($M)	3.2	7.0	11.1	13.8	16.8	19.9	23.3	26.8	34.3	48.7	63.6	76.8
45,473	4.17	Nominal	**Total Resource Cost ($M)**	2,216	2,205	2,249	2,343	2,444	2,571	2,662	2,700	2,979	3,426	3,950	4,592
	0.84	Real		2,216	2,135	2,108	2,125	2,146	2,186	2,190	2,151	2,224	2,320	2,427	2,478
	2.37	Nominal	Cost in mills/kWh	48.9	48.4	48.6	49.5	50.5	51.9	52.5	52.1	55.5	60.7	66.0	74.1
	-0.90	Real		48.9	46.9	45.5	44.9	44.4	44.1	43.2	41.5	41.4	41.1	40.5	40.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.29**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.97**

Med Load - Med Gas
with Extension of Loads & DSM to 2045

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	50,010	49,857	50,259	51,018	52,149	53,014	54,042	55,182	57,293	60,683	66,844	77,162
	MWa	5,709	5,691	5,737	5,824	5,953	6,052	6,169	6,299	6,540	6,927	7,631	8,809
	Total Annual Emissions (1000 Tons)												
0.14%	CO2	51,967	51,991	52,172	52,649	53,395	53,850	54,318	54,672	55,666	57,485	59,169	53,337
0.21%	NOx	121.1	121.6	122.0	122.4	123.3	123.6	126.5	126.0	126.2	126.5	126.8	126.1
0.25%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.1	11.1	11.2	11.3	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-2.12%	CO2	2,078	2,086	2,076	2,064	2,048	2,032	2,010	1,982	1,943	1,895	1,770	1,382
-2.05%	NOx	4.84	4.88	4.85	4.80	4.73	4.66	4.68	4.57	4.40	4.17	3.79	3.27
-2.01%	TSP	0.43	0.44	0.43	0.43	0.42	0.42	0.41	0.40	0.39	0.37	0.34	0.30
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.35	99.90	99.31	98.53	97.75	96.73	95.34	93.50	91.16	85.18	66.52
	NOx	100	100.65	100.17	99.07	97.61	96.26	96.66	94.24	90.90	86.06	78.28	67.47
	TSP	100	100.49	100.08	99.09	97.63	96.44	94.89	92.99	90.00	85.55	78.03	67.98

20 Year Emissions (1000 Tons)	Average	Total
CO2	55,220	1,104,404
NOx	125.2	2,503
TSP	11.2	224

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Med Load - Med Gas
with Extension of All Modeling to 2045

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.1	15.4	15.9	16.4	16.8	17.1	16.9	17.1	41.9	62.4	58.9	74.5	367.4
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								150.4	150.4				300.8
C	OWC Cogen 2								205.7	162.9	380.5	491.7		1240.8
	OWC Combined Cycle												437.3	437.3
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.1**	**15.4**	**15.9**	**16.4**	**16.8**	**17.1**	**16.9**	**373.2**	**355.2**	**442.9**	**550.6**	**511.8**	**2346.3**
	DSM Programs	11.4	12.5	14.3	14.4	14.5	14.8	14.6	14.8	37.4	57.0	54.7	70.1	330.5
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1												36.7	36.7
U	Utah Cogen 2									50.4	206.2	138.2		394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							64.6	168.0	64.7				297.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT											107.6		107.6
	Utah Compressed Air													0.0
	Utah Pumped Storage												200.0	200.0
	Total	**11.4**	**12.5**	**14.3**	**14.4**	**14.5**	**14.8**	**79.2**	**182.8**	**152.5**	**263.2**	**300.5**	**306.8**	**1366.9**
	DSM Programs	4.5	4.5	4.6	4.6	5.3	5.3	5.3	5.4	12.9	19.6	18.8	23.9	114.7
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.5**	**4.5**	**4.6**	**4.6**	**5.3**	**5.3**	**5.3**	**5.4**	**12.9**	**19.6**	**18.8**	**23.9**	**114.7**
	DSM Programs	30.0	32.4	34.8	35.4	36.6	37.2	36.8	37.3	92.2	139.0	132.4	168.5	812.6
T	Renewable													0.0
O	Cogeneration								356.1	363.7	586.7	629.9	36.7	1973.1
T	Combined Cycle CT							64.6	168.0	64.7			437.3	734.6
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT											107.6		107.6
	Pumped Storage												200.0	200.0
	Total	**30.0**	**32.4**	**34.8**	**35.4**	**36.6**	**37.2**	**101.4**	**561.4**	**520.6**	**725.7**	**869.9**	**842.5**	**3827.9**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	2,115	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130
S	DSM Programs	(30)	(62)	(97)	(133)	(169)	(206)	(243)	(281)	(373)	(512)	(644)	(813)
T	**Total Requirements**	**9,024**	**9,154**	**9,260**	**9,605**	**9,821**	**9,919**	**10,094**	**10,263**	**10,564**	**10,991**	**11,520**	**12,099**
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,207	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	758	738	732	725	718	697	692	692	692	692
L	New Resources							65	589	1,017	1,604	2,341	3,015
&	Summer Purch $6/Year					83	183	315					
R	Total Resources	10,250	10,741	10,904	10,908	11,000	11,109	11,305	11,494	11,832	12,310	12,902	13,550
	Reserves	1,226	1,587	1,644	1,303	1,179	1,190	1,211	1,231	1,268	1,319	1,382	1,451
	Reserve Margin (RM) (%)	13.6	17.3	17.7	13.6	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Med Load - Med Gas
with Extension of All Modeling to 2045

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.0	21.3	22.4	23.3	24.2	24.5	24.5	24.8	55.5	82.1	75.9	94.6	491.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1								160.0	160.0				320.0
C	OWC Cogen 2								218.8	173.4	404.7	523.1		1320.0
	OWC Combined Cycle												465.3	465.3
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.0**	**21.3**	**22.4**	**23.3**	**24.2**	**24.5**	**24.5**	**403.6**	**388.9**	**486.8**	**599.0**	**559.9**	**2596.4**
	DSM Programs	13.8	15.3	17.4	17.5	17.7	17.8	17.6	17.7	41.3	62.6	59.1	75.2	373.0
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1												39.0	39.0
U	Utah Cogen 2									53.6	219.4	147.0		420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower							72.0	187.2	72.0				331.2
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT											114.4		114.4
	Utah Compressed Air													0.0
	Utah Pumped Storage												200.0	200.0
	Total	**13.8**	**15.3**	**17.4**	**17.5**	**17.7**	**17.8**	**89.6**	**204.9**	**166.9**	**282.0**	**320.5**	**314.2**	**1477.6**
	DSM Programs	4.0	4.1	4.1	4.2	4.9	4.9	4.9	5.0	11.1	16.8	15.8	19.9	99.7
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**4.0**	**4.1**	**4.1**	**4.2**	**4.9**	**4.9**	**4.9**	**5.0**	**11.1**	**16.8**	**15.8**	**19.9**	**99.7**
	DSM Programs	35.8	40.7	43.9	45.0	46.8	47.2	47.0	47.5	107.9	161.5	150.8	189.7	963.8
T	Renewable													0.0
O	Cogeneration								378.8	387.0	624.1	670.1	39.0	2099.0
T	Combined Cycle CT							72.0	187.2	72.0			465.3	796.5
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT											114.4		114.4
	Pumped Storage												200.0	200.0
	Total	**35.8**	**40.7**	**43.9**	**45.0**	**46.8**	**47.2**	**119.0**	**613.5**	**566.9**	**785.6**	**935.3**	**894.0**	**4173.7**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463
S	DSM Programs	(36)	(77)	(120)	(165)	(212)	(259)	(306)	(354)	(462)	(623)	(774)	(964)
T	**Total Requirements**	**8,996**	**9,018**	**9,079**	**9,192**	**9,336**	**9,483**	**9,635**	**9,803**	**10,105**	**10,572**	**11,033**	**11,584**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,227	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	905	1,010	1,004	979	972	967	959	954	954	954	954
L	New Resources							72	638	1,097	1,721	2,506	3,210
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,930**	**11,200**	**11,221**	**11,206**	**11,216**	**11,290**	**11,852**	**12,212**	**12,722**	**13,353**	**14,033**
	Reserves	1,352	1,913	2,121	2,029	1,870	1,733	1,656	2,049	2,107	2,150	2,320	2,449
	Reserve Margin (RM) (%)	15.0	21.2	23.4	22.1	20.0	18.3	17.2	20.9	20.9	20.3	21.0	21.1

PacifiCorp RAMPP-4

Case # 67

Med Load - Med Gas
with Extension of All Modeling to 2045

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.0	18.8	28.9	39.4	50.3	61.3	72.2	83.3	109.1	147.6	184.0	229.9
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal								148.9	297.9	297.9	297.9	297.9
W	OWC Cogen 1								203.6	364.9	701.0	1,107.2	1,162.2
C	OWC Cogen 2												203.8
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	9.0	18.8	28.9	39.4	50.3	61.3	72.2	435.8	771.9	1,146.5	1,589.0	1,893.8
	DSM Programs	8.1	16.9	27.3	37.7	48.3	59.1	69.8	80.6	106.1	145.0	182.5	230.6
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal												36.3
	Utah Cogen 1									49.9	250.6	354.4	376.1
U	Utah Cogen 2												
T	Utah Combined Cycle							54.1	182.6	203.3	176.8	131.6	176.3
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton											4.3	4.3
	Utah Simple Cycle CT												
	Utah Compressed Air												10.9
	Utah Pumped Storage												
	Total	8.1	16.9	27.3	37.7	48.3	59.1	123.9	263.2	359.4	572.5	672.9	834.5
	DSM Programs	3.3	6.7	10.1	13.6	17.7	21.8	25.9	30.1	39.5	53.7	67.4	84.8
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	3.3	6.7	10.1	13.6	17.7	21.8	25.9	30.1	39.5	53.7	67.4	84.8
	DSM Programs	20.5	42.4	66.3	90.7	116.2	142.1	167.9	194.0	254.7	346.4	433.9	545.3
T	Renewable								352.5	712.7	1,249.5	1,759.5	1,872.5
O	Cogeneration							54.1	182.6	203.3	176.8	131.6	380.1
T	Combined Cycle CT												
A	Coal & IGCC												
L	Transmission											4.3	4.3
	Simple Cycle CT												10.9
	Pumped Storage												
	Total	20.5	42.4	66.3	90.7	116.2	142.1	222.0	729.2	1,170.7	1,772.6	2,329.2	2,813.1
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	310.6	309.6	309.3	307.2	307.0	307.0	307.0	306.8	305.0	305.0	305.0	319.0
S	**Firm Sales**	1,605.8	1,622.6	1,622.4	1,676.7	1,682.6	1,682.6	1,682.6	1,682.6	1,682.6	1,682.6	1,682.6	1,682.6
T	**Non-Firm Sales**	530.0	775.8	802.7	721.1	662.3	640.2	606.5	851.3	970.1	1,010.4	1,034.5	1,039.3
E	**DSM Programs**	(20.4)	(42.4)	(66.3)	(90.7)	(116.2)	(142.1)	(167.9)	(194.0)	(254.7)	(346.3)	(433.9)	(545.3)
M	**Total Requirements**	7,840.1	8,082.5	8,152.2	8,209.5	8,283.7	8,357.9	8,441.0	8,815.1	9,165.7	9,583.8	9,938.8	10,327.9
	Existing Generation	7,155.5	7,511.8	7,558.1	7,611.2	7,667.2	7,705.9	7,738.3	7,748.0	7,726.3	7,634.1	7,520.1	7,536.6
L	**Firm Purchases**	557.0	536.0	553.2	545.0	538.1	533.0	529.7	526.5	523.4	523.4	523.4	523.4
&	**Non-Firm Purchases**	127.6	34.7	41.0	53.4	78.4	119.0	119.0	5.3				
R	**New Resources**							54.1	535.2	916.0	1,426.3	1,895.4	2,267.8
	Total Resources	7,840.1	8,082.5	8,152.2	8,209.5	8,283.7	8,357.9	8,441.0	8,815.1	9,165.7	9,583.8	9,938.9	10,327.9

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Case # 67

Med Load - Med Gas
with Extension of All Modeling to 2045

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	20	42	66	90	116	142	168	194	251	343	430	545
			After Conservation												
			System Load (MWa)	5,704	5,685	5,728	5,815	5,942	6,039	6,155	6,285	6,522	6,899	7,231	7,597
	1.67		Energy Sales (MWa)	5,155	5,164	5,225	5,316	5,418	5,523	5,631	5,740	5,904	6,131	6,442	6,576
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,078	8,274	8,459	8,664	8,896	9,416	10,013	10,444	11,182	12,561	14,128	16,054
			Net Conservation Assets ($M)	46	93	143	179	212	245	276	305	371	469	535	624
			Utility Cost												
45,141	4.20	Nominal	**Operating Revenues ($M)**	2,212	2,207	2,273	2,339	2,439	2,565	2,642	2,672	2,937	3,311	3,913	4,410
	0.87	Real		2,212	2,136	2,131	2,122	2,142	2,181	2,174	2,129	2,193	2,242	2,404	2,380
	2.49	Nominal	Cost in mills/kWh	49.0	48.8	49.7	50.2	51.4	53.0	53.6	53.1	56.8	61.6	69.3	76.6
	-0.78	Real		49.0	47.2	46.6	45.6	45.1	45.1	44.1	42.3	42.4	41.8	42.6	41.3
		Nominal	Average Customer Bill ($)	1,668	1,648	1,675	1,695	1,736	1,796	1,820	1,810	1,927	2,071	2,347	2,576
		Real		1,668	1,595	1,570	1,538	1,524	1,527	1,498	1,442	1,438	1,402	1,442	1,390
			Total Resource Cost												
			DSR Customer Cost ($M)	0.8	1.7	2.6	4.9	7.1	8.9	10.6	11.8	13.8	14.3	10.7	-3.3
			Levelized (20-year at 8.6%)	0.1	0.3	0.6	1.1	1.8	2.8	3.9	5.2	7.9	12.6	16.5	18.1
			Energy Svc Charge ($M)	3.9	8.2	13.0	16.0	19.3	22.6	26.1	29.7	38.7	55.6	69.8	81.3
45,656	4.20	Nominal	**Total Resource Cost ($M)**	2,216	2,215	2,287	2,356	2,460	2,591	2,672	2,707	2,984	3,379	3,999	4,509
	0.87	Real		2,216	2,145	2,143	2,137	2,160	2,203	2,199	2,157	2,228	2,289	2,457	2,433
	2.41	Nominal	Cost in mills/kWh	48.9	48.6	49.4	49.8	50.8	52.3	52.7	52.2	55.5	59.8	66.8	72.8
	-0.87	Real		48.9	47.1	46.3	45.2	44.6	44.5	43.4	41.6	41.5	40.5	41.0	39.3

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.53**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.13**

Med Load - Med Gas
with Extension of All Modeling to 2045

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,970	49,793	50,170	50,911	52,024	52,867	53,891	55,023	57,054	60,363	66,628	77,015
	MWa	5,704	5,684	5,727	5,812	5,939	6,035	6,152	6,281	6,513	6,891	7,606	8,792
	Total Annual Emissions (1000 Tons)												
-0.05%	CO2	51,913	51,810	52,072	52,627	53,382	53,810	54,228	54,548	55,425	57,199	58,964	51,425
0.24%	NOx	121.0	121.4	121.8	122.5	123.5	123.8	127.0	126.3	126.3	126.6	127.2	126.7
0.27%	TSP	10.9	10.9	10.9	11.0	11.1	11.1	11.2	11.1	11.2	11.2	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
-2.30%	CO2	2,078	2,081	2,076	2,067	2,052	2,036	2,013	1,983	1,943	1,895	1,770	1,335
-2.02%	NOx	4.84	4.88	4.85	4.81	4.75	4.68	4.71	4.59	4.43	4.20	3.82	3.29
-1.99%	TSP	0.43	0.44	0.43	0.43	0.43	0.42	0.41	0.41	0.39	0.37	0.34	0.30
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.16	99.91	99.50	98.77	97.97	96.86	95.43	93.51	91.21	85.18	64.27
	NOx	100	100.70	100.20	99.35	98.01	96.68	97.29	94.78	91.40	86.61	78.83	67.91
	TSP	100	100.53	100.13	99.44	98.10	96.92	95.28	93.30	90.27	85.72	78.22	68.25

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,838	1,096,761
NOx	125.4	2,508
TSP	11.2	224

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Case # 71

Med Load - Med Gas
Low Environmental Adders

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	16.4	16.9	17.1	17.0	17.1	33.4	49.7	46.0	56.4	316.1
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1					150.4	150.4							300.8
C	OWC Cogen 2					50.1			202.5		5.3	297.6	558.1	1113.6
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.3**	**15.7**	**16.1**	**16.4**	**217.4**	**167.5**	**17.0**	**219.6**	**33.4**	**55.0**	**343.6**	**614.5**	**1730.5**
	DSM Programs	13.0	14.2	14.6	14.7	14.8	14.8	14.7	14.7	29.0	44.0	41.7	51.9	282.1
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1					36.7								36.7
U	Utah Cogen 2					197.4	197.4							394.8
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower					168.0	129.4							297.4
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**13.0**	**14.2**	**14.6**	**14.7**	**416.9**	**341.6**	**14.7**	**14.7**	**29.0**	**44.0**	**41.7**	**51.9**	**1011.0**
	DSM Programs	5.0	5.3	5.3	5.4	5.4	5.4	5.5	5.4	10.7	16.3	15.4	19.0	104.1
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**5.0**	**5.3**	**5.3**	**5.4**	**5.4**	**5.4**	**5.5**	**5.4**	**10.7**	**16.3**	**15.4**	**19.0**	**104.1**
	DSM Programs	32.3	35.2	36.0	36.5	37.1	37.3	37.2	37.2	73.1	110.0	103.1	127.3	702.3
T	Renewable													0.0
O	Cogeneration					434.6	347.8		202.5		5.3	297.6	558.1	1845.9
T	Combined Cycle CT					168.0	129.4							297.4
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**32.3**	**35.2**	**36.0**	**36.5**	**639.7**	**514.5**	**37.2**	**239.7**	**73.1**	**115.3**	**400.7**	**685.4**	**2845.6**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(32)	(68)	(104)	(140)	(177)	(214)	(252)	(289)	(362)	(472)	(575)	(702)
T	**Total Requirements**	**9,022**	**9,149**	**9,254**	**9,358**	**9,573**	**9,576**	**9,750**	**9,919**	**9,930**	**10,078**	**10,561**	**11,007**
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources					603	1,080	1,080	1,282	1,282	1,288	1,585	2,143
&	Summer Purch $6/Year												
R	**Total Resources**	**10,250**	**10,741**	**10,804**	**10,808**	**11,419**	**11,888**	**11,888**	**12,069**	**11,829**	**11,726**	**11,828**	**12,327**
	Reserves	1,228	1,593	1,551	1,450	1,847	2,312	2,137	2,150	1,899	1,648	1,267	1,321
	Reserve Margin (RM) (%)	13.6	17.4	16.7	15.5	19.3	24.1	21.9	21.7	19.1	16.3	12.0	12.0

Med Load - Med Gas
Low Environmental Adders

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	23.5	24.4	24.8	24.7	25.0	48.8	71.9	65.3	79.0	450.5
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal													0.0
W	OWC Cogen 1					160.0	160.0							320.0
C	OWC Cogen 2					53.3			215.4		5.7	316.6	593.6	1184.6
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.4**	**21.8**	**22.9**	**23.5**	**237.7**	**184.8**	**24.7**	**240.4**	**48.8**	**77.6**	**381.9**	**672.6**	**1955.1**
	DSM Programs	15.5	16.9	17.8	17.9	18.1	17.9	17.8	17.8	34.9	52.7	49.2	60.7	337.2
	Utah Wind Non-firm													0.0
	Utah Wind Firm													0.0
	Utah Geothermal													0.0
	Utah Cogen 1					39.0								39.0
U	Utah Cogen 2					210.0	210.0							420.0
T	Utah Combined Cycle													0.0
A	Utah Gadsby Repower					187.2	144.1							331.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**15.5**	**16.9**	**17.8**	**17.9**	**454.3**	**372.0**	**17.8**	**17.8**	**34.9**	**52.7**	**49.2**	**60.7**	**1127.5**
	DSM Programs	4.8	5.0	5.1	5.2	5.3	5.5	5.4	5.6	11.0	17.2	16.3	20.5	106.9
W	Wyo Wind Non-firm													0.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle													0.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	4.8	5.0	5.1	5.2	5.3	5.5	5.4	5.6	11.0	17.2	16.3	20.5	106.9
	DSM Programs	38.7	43.7	45.8	46.6	47.8	48.2	47.9	48.4	94.7	141.8	130.8	160.2	894.6
T	Renewable													0.0
O	Cogeneration					462.3	370.0		215.4		5.7	316.6	593.6	1963.6
T	Combined Cycle CT					187.2	144.1							331.3
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**38.7**	**43.7**	**45.8**	**46.6**	**697.3**	**562.3**	**47.9**	**263.8**	**94.7**	**147.5**	**447.4**	**753.8**	**3189.5**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(39)	(82)	(128)	(175)	(223)	(271)	(319)	(367)	(462)	(604)	(734)	(895)
T	**Total Requirements**	**8,993**	**9,012**	**9,071**	**9,082**	**9,175**	**9,321**	**9,472**	**9,640**	**9,637**	**9,865**	**10,222**	**10,627**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,228	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources					650	1,164	1,164	1,379	1,379	1,385	1,701	2,295
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,850	11,020	11,041	11,676	12,182	12,184	12,395	11,859	11,701	11,863	12,433
	Reserves	1,355	1,838	1,949	1,959	2,501	2,860	2,711	2,755	2,222	1,835	1,642	1,806
	Reserve Margin (RM) (%)	15.1	20.4	21.5	21.6	27.3	30.7	28.6	28.6	23.1	18.6	16.1	17.0

Med Load - Med Gas
Low Environmental Adders

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	40.4	51.3	62.4	73.5	84.6	106.4	138.8	168.9	205.8
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal					148.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9
W	OWC Cogen 1					49.6	49.6	49.6	250.0	250.0	255.3	549.9	1,102.3
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**9.3**	**19.3**	**29.7**	**40.4**	**249.8**	**409.9**	**420.9**	**632.5**	**654.3**	**692.0**	**1,016.7**	**1,606.0**
	DSM Programs	9.8	20.2	30.9	41.7	52.6	63.4	74.2	85.0	106.4	138.8	169.9	208.5
	Utah Wind Non-firm												
	Utah Wind Firm												
	Utah Geothermal					36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
	Utah Cogen 1					195.4	390.8	390.8	390.8	390.8	390.8	390.8	390.8
U	Utah Cogen 2												
T	Utah Combined Cycle					170.3	301.8	301.8	301.8	301.8	301.8	301.8	301.8
A	Utah Gadsby Repower												
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	**9.8**	**20.2**	**30.9**	**41.7**	**454.6**	**792.3**	**803.1**	**813.9**	**835.3**	**867.7**	**898.8**	**937.4**
	DSM Programs	4.0	8.2	12.5	16.7	21.1	25.5	29.9	34.3	43.0	56.5	69.4	85.6
W	Wyo Wind Non-firm												
Y	Wyo Wind Firm												
O	Wyo Combined Cycle												
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	**4.0**	**8.2**	**12.5**	**16.7**	**21.1**	**25.5**	**29.9**	**34.3**	**43.0**	**56.5**	**69.4**	**85.6**
	DSM Programs	23.1	47.7	73.1	98.8	124.9	151.3	177.5	203.9	255.8	334.1	408.2	500.0
T	Renewable					430.2	774.6	774.6	975.0	975.0	980.3	1,274.9	1,827.2
O	Cogeneration					170.3	301.8	301.8	301.8	301.8	301.8	301.8	301.8
T	Combined Cycle CT												
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	**23.1**	**47.7**	**73.1**	**98.8**	**725.5**	**1,227.6**	**1,253.9**	**1,480.7**	**1,532.6**	**1,616.2**	**1,984.9**	**2,629.0**
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	285.7	298.6	307.1	306.5	264.4	281.9	306.2	306.6	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**							18.2	224.7	239.3	189.0	376.5	850.6
E	**DSM Programs**	(23.1)	(47.7)	(73.1)	(98.8)	(124.9)	(151.3)	(177.5)	(203.9)	(255.8)	(334.1)	(408.2)	(500.0)
M	**Total Requirements**	7,282.6	7,290.4	7,290.5	7,336.5	7,402.0	7,490.6	7,649.5	7,950.5	8,016.6	8,184.8	8,661.1	9,316.3
	Existing Generation	5,998.5	6,065.6	6,096.5	6,150.7	5,626.2	5,247.7	5,488.7	5,774.5	5,891.8	6,112.3	6,378.3	6,631.3
L	**Firm Purchases**	563.3	503.9	473.1	464.9	454.3	445.7	442.5	439.3	399.6	381.7	378.6	358.5
&	**Non-Firm Purchases**	720.9	720.9	720.9	720.9	720.9	720.9	642.0	459.9	448.5	408.7	327.5	197.4
R	**New Resources**					600.6	1,076.4	1,076.4	1,276.8	1,276.8	1,282.1	1,576.7	2,129.0
	Total Resources	7,282.6	7,290.4	7,290.5	7,336.5	7,402.0	7,490.6	7,649.5	7,950.5	8,016.6	8,184.8	8,661.1	9,316.2

Case # 71

Med Load - Med Gas
Low Environmental Adders

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	23	47	73	98	124	151	177	203	256	335	408	505
			After Conservation												
			System Load (MWa)	5,701	5,679	5,722	5,807	5,934	6,030	6,146	6,275	6,517	6,907	7,253	7,637
	0.52		Energy Sales (MWa)	5,152	5,159	5,218	5,309	5,410	5,515	5,623	5,731	5,899	6,139	6,462	6,612
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,084	8,323	8,868	9,763	10,262	10,493	10,761	10,906	11,218	11,764	12,759	14,637
			Net Conservation Assets ($M)	51	104	158	194	228	261	292	321	373	431	460	512
			<u>Utility Cost</u>												
43,665	3.24	Nominal	**Operating Revenues ($M)**	2,253	2,263	2,322	2,419	2,505	2,734	2,890	2,948	3,191	3,543	3,963	4,462
	-0.06	Real		2,253	2,191	2,176	2,195	2,200	2,324	2,378	2,348	2,383	2,400	2,435	2,408
	2.70	Nominal	Cost in mills/kWh	49.9	50.1	50.8	52.0	52.9	56.6	58.7	58.7	61.8	65.9	70.0	77.0
	-0.58	Real		49.9	48.5	47.6	47.2	46.4	48.1	48.3	46.8	46.1	44.6	43.0	41.6
		Nominal	Average Customer Bill ($)	1,699	1,690	1,711	1,753	1,783	1,914	1,991	1,997	2,093	2,216	2,377	2,607
		Real		1,699	1,636	1,603	1,591	1,566	1,627	1,638	1,591	1,563	1,501	1,460	1,407
			<u>Total Resource Cost</u>												
			DSR Customer Cost ($M)	0.5	1.4	2.3	5.0	7.2	8.9	10.6	11.8	12.0	6.7	-3.7	-28.8
			Levelized (20-year at 8.6%)	0.1	0.2	0.5	1.0	1.7	2.7	3.8	5.1	7.6	10.5	11.0	11.0
			Energy Svc Charge ($M)	4.5	9.3	14.4	17.6	20.9	24.3	27.8	31.4	38.9	50.9	59.3	61.8
44,110	3.23	Nominal	**Total Resource Cost ($M)**	2,257	2,272	2,337	2,438	2,527	2,761	2,921	2,984	3,238	3,604	4,033	4,535
	-0.06	Real		2,257	2,200	2,190	2,212	2,220	2,347	2,404	2,377	2,417	2,441	2,478	2,447
	2.56	Nominal	Cost in mills/kWh	49.8	49.9	50.5	51.6	52.2	55.8	57.7	57.6	60.3	63.8	67.4	73.2
	-0.72	Real		49.8	48.3	47.3	46.8	45.9	47.4	47.5	45.9	45.0	43.2	41.4	39.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 43.74

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 42.13

Med Load - Med Gas
Low Environmental Adders

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,729	49,650	50,092	50,833	51,573	52,566	53,799	54,935	57,044	60,469	66,902	66,622
	MWa	5,677	5,668	5,718	5,803	5,887	6,001	6,141	6,271	6,512	6,903	7,637	7,605
	Total Annual Emissions (1000 Tons)												
0.03%	CO2	45,167	43,305	42,579	43,220	40,138	37,953	39,670	41,941	43,586	47,251	51,126	45,449
0.33%	NOx	98.0	91.9	89.0	90.1	78.1	69.6	76.9	82.8	85.2	91.7	99.5	104.4
0.13%	TSP	9.4	8.7	8.5	8.6	7.5	6.9	7.2	7.8	8.0	8.6	9.4	9.6
	Annual System Emission Rates (Pounds/MWh)												
-1.50%	CO2	1,817	1,744	1,700	1,700	1,557	1,444	1,475	1,527	1,528	1,563	1,528	1,364
-1.20%	NOx	3.94	3.70	3.55	3.55	3.03	2.65	2.86	3.01	2.99	3.03	2.97	3.13
-1.40%	TSP	0.38	0.35	0.34	0.34	0.29	0.26	0.27	0.28	0.28	0.29	0.28	0.29
	Emission Rates as Percent of 1994 Base												
	CO2	100	96.03	93.59	93.61	85.69	79.49	81.18	84.06	84.13	86.03	84.14	75.11
	NOx	100	93.89	90.16	89.94	76.82	67.20	72.48	76.44	75.74	76.97	75.45	79.50
	TSP	100	93.06	89.41	89.44	77.47	69.36	71.20	74.73	74.00	75.62	74.70	76.45

20 Year Emissions (1000 Tons)	Average	Total
CO2	44,911	898,226
NOx	90.8	1,815
TSP	8.6	171

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Med Load - Med Gas
Medium Environmental Adders

Incremental Summer Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	14.3	15.7	16.1	16.4	16.9	17.1	17.0	17.1	41.9	62.4	58.9	73.2	367.0
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal				100.0	100.0					100.0			300.0
W	OWC Cogen 1					150.4	150.4							300.8
C	OWC Cogen 2					441.8	441.8	346.1	11.1					1240.8
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**14.3**	**15.7**	**16.1**	**116.4**	**709.1**	**609.3**	**363.1**	**28.2**	**41.9**	**162.4**	**58.9**	**73.2**	**2208.6**
	DSM Programs	18.1	18.5	18.9	19.0	19.2	19.1	18.9	19.1	37.5	56.9	54.7	68.0	367.9
	Utah Wind Non-firm			23.0	23.0									46.0
	Utah Wind Firm													0.0
	Utah Geothermal				100.0	100.0	100.0							300.0
	Utah Cogen 1					36.7								36.7
U	Utah Cogen 2					197.4	197.4							394.8
T	Utah Combined Cycle					423.0	423.0	323.0						1169.0
A	Utah Gadsby Repower					168.0	129.4							297.4
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	18.1	18.5	41.9	**142.0**	**944.3**	**868.9**	**341.9**	**19.1**	**37.5**	56.9	54.7	68.0	**2611.8**
	DSM Programs	6.3	6.4	6.5	6.4	6.6	6.5	6.6	6.5	13.0	19.6	18.8	23.2	126.4
W	Wyo Wind Non-firm			23.0	23.0									46.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle					423.0								423.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	6.3	6.4	29.5	29.4	429.6	6.5	6.6	6.5	13.0	19.6	18.8	23.2	595.4
	DSM Programs	38.7	40.6	41.5	41.8	42.7	42.7	42.5	42.7	92.4	138.9	132.4	164.4	861.3
T	Renewable			46.0	246.0	200.0	100.0				100.0			692.0
O	Cogeneration					826.3	789.6	346.1	11.1					1973.1
T	Combined Cycle CT					1,014.0	552.4	323.0						1889.4
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**38.7**	**40.6**	**87.5**	**287.8**	**2,083.0**	**1,484.7**	**711.6**	**53.8**	**92.4**	**238.9**	**132.4**	**164.4**	**5415.8**

Annual Summer Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Y	Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
S	DSM Programs	(39)	(79)	(121)	(163)	(205)	(248)	(291)	(333)	(426)	(565)	(697)	(861)
T	**Total Requirements**	9,015	9,137	9,236	9,335	9,545	9,542	9,712	9,875	9,866	9,986	10,439	10,848
E													
M	Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
	Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
L	New Resources			46	292	2,332	3,774	4,443	4,455	4,455	4,555	4,555	4,555
&	Summer Purch $6/Year												
R	**Total Resources**	10,250	10,741	10,850	11,100	13,149	14,582	15,251	15,242	15,002	14,993	14,798	14,739
	Reserves	1,235	1,604	1,583	1,570	3,276	4,646	5,145	4,972	4,740	4,546	3,897	3,429
	Reserve Margin (RM) (%)	13.7	17.5	17.5	18.9	37.8	52.8	57.0	54.3	52.0	50.1	41.7	35.9

9/18/95 7:38 PM

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Case # 72

Med Load - Med Gas
Medium Environmental Adders

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	18.4	21.8	22.9	23.5	24.4	24.8	24.7	25.0	55.6	82.3	75.7	92.7	491.8
	OWC Wind Non-Firm													0.0
	OWC Wind Firm													0.0
O	OWC Geothermal				100.0	100.0					100.0			300.0
W	OWC Cogen 1					160.0	160.0							320.0
C	OWC Cogen 2					470.0	470.0	368.2	11.8					1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**18.4**	**21.8**	**22.9**	**123.5**	**754.4**	**654.8**	**392.9**	**36.8**	**55.6**	**182.3**	**75.7**	**92.7**	**2431.8**
	DSM Programs	19.5	20.3	21.2	21.3	21.4	21.4	21.1	21.2	41.6	62.9	59.3	73.4	404.6
	Utah Wind Non-firm			53.0	53.0									106.0
	Utah Wind Firm													0.0
	Utah Geothermal				100.0	100.0	100.0							300.0
	Utah Cogen 1					39.0								39.0
U	Utah Cogen 2					210.0	210.0							420.0
T	Utah Combined Cycle					450.0	450.0	343.6						1243.6
A	Utah Gadsby Repower					187.2	144.1							331.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**19.5**	**20.3**	**74.2**	**174.3**	**1,007.6**	**925.5**	**364.7**	**21.2**	**41.6**	**62.9**	**59.3**	**73.4**	**2844.5**
	DSM Programs	5.5	5.6	5.7	5.7	5.9	6.0	6.1	6.1	12.2	18.8	18.1	22.7	118.4
W	Wyo Wind Non-firm			53.0	53.0									106.0
Y	Wyo Wind Firm													0.0
O	Wyo Combined Cycle					450.0								450.0
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**5.5**	**5.6**	**58.7**	**58.7**	**455.9**	**6.0**	**6.1**	**6.1**	**12.2**	**18.8**	**18.1**	**22.7**	**674.4**
	DSM Programs	43.4	47.7	49.8	50.5	51.7	52.2	51.9	52.3	109.4	164.0	153.1	188.8	1014.8
T	Renewable			106.0	306.0	200.0	100.0				100.0			812.0
O	Cogeneration					879.0	840.0	368.2	11.8					2099.0
T	Combined Cycle CT					1,087.2	594.1	343.6						2024.9
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**43.4**	**47.7**	**155.8**	**356.5**	**2,217.9**	**1,586.3**	**763.7**	**64.1**	**109.4**	**264.0**	**153.1**	**188.8**	**5950.7**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(43)	(91)	(141)	(191)	(243)	(295)	(347)	(400)	(509)	(673)	(826)	(1,015)
T	**Total Requirements**	**8,989**	**9,003**	**9,058**	**9,066**	**9,155**	**9,297**	**9,444**	**9,608**	**9,590**	**9,796**	**10,130**	**10,507**
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,228	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources			106	412	2,578	4,112	4,824	4,836	4,836	4,936	4,936	4,936
&	Summer Purch $6/Year												
R	**Total Resources**	**10,348**	**10,850**	**11,126**	**11,453**	**13,605**	**15,130**	**15,844**	**15,852**	**15,316**	**15,252**	**15,098**	**15,074**
	Reserves	1,359	1,847	1,997	2,113	4,042	5,359	5,926	5,770	5,251	4,914	4,427	4,025
	Reserve Margin (RM) (%)	15.1	20.5	22.8	26.3	48.6	62.7	67.8	65.0	59.7	55.7	49.0	43.5

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9/18/95 7:38 PM

Med Load - Med Gas
Medium Environmental Adders

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	9.3	19.3	29.7	40.4	51.3	62.4	73.5	84.6	110.4	149.0	185.3	230.4
	OWC Wind Non-Firm												
	OWC Wind Firm												
O	OWC Geothermal				94.8	189.6	189.6	189.6	189.6	189.6	284.4	284.4	284.4
W	OWC Cogen 1					148.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2					437.3	874.6	1,217.2	1,228.2	1,228.2	1,228.2	1,228.2	1,228.2
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	9.3	19.3	29.7	135.2	827.2	1,424.5	1,778.1	1,800.3	1,826.1	1,959.5	1,995.8	2,040.9
	DSM Programs	12.3	25.0	37.8	50.8	63.9	76.9	89.9	102.9	128.5	167.6	205.1	251.9
	Utah Wind Non-firm			33.4	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7
	Utah Wind Firm												
	Utah Geothermal				94.8	189.6	284.4	284.4	284.4	284.4	284.4	284.4	284.4
	Utah Cogen 1					36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
U	Utah Cogen 2					195.4	390.8	390.8	390.8	390.8	390.8	390.8	390.8
T	Utah Combined Cycle					418.7	837.4	1,157.1	1,157.1	1,157.1	1,157.1	1,157.1	1,157.1
A	Utah Gadsby Repower					170.3	301.8	301.8	301.8	301.8	301.8	301.8	301.8
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	12.3	25.0	71.2	212.3	1,140.9	1,994.4	2,327.0	2,340.0	2,365.7	2,404.7	2,442.3	2,489.1
	DSM Programs	4.6	9.3	14.1	18.9	23.7	28.6	33.5	38.4	48.2	63.2	77.7	95.8
W	Wyo Wind Non-firm			33.4	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7
Y	Wyo Wind Firm												
O	Wyo Combined Cycle					418.7	418.7	418.7	418.7	418.7	418.7	418.7	418.7
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	4.6	9.3	47.5	85.6	509.1	514.0	518.9	523.9	533.6	548.6	563.1	581.2
	DSM Programs	26.2	53.6	81.7	110.0	138.9	167.9	196.8	225.9	287.2	379.7	468.1	578.0
T	Renewable			66.7	323.1	512.7	607.5	607.5	607.5	607.5	702.3	702.3	702.3
O	Cogeneration					817.9	1,599.6	1,942.1	1,953.2	1,953.2	1,953.2	1,953.2	1,953.2
T	Combined Cycle CT					1,007.7	1,557.9	1,877.6	1,877.6	1,877.6	1,877.6	1,877.6	1,877.6
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	26.2	53.6	148.4	433.1	2,477.2	3,932.9	4,624.1	4,664.2	4,725.4	4,912.8	5,001.2	5,111.1
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	291.9	290.9	295.2	286.9	305.6	304.5	306.2	306.4	300.4	275.2	255.5	290.8
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**						23.1	181.0	157.9	179.8	122.0	30.4	30.0
E	**DSM Programs**	(26.2)	(53.6)	(81.6)	(110.0)	(138.9)	(167.9)	(196.8)	(225.9)	(287.2)	(379.7)	(468.1)	(578.0)
M	**Total Requirements**	7,285.7	7,276.8	7,270.0	7,305.7	7,429.2	7,519.6	7,793.0	7,861.5	7,921.2	8,042.3	8,205.5	8,403.3
	Existing Generation	5,897.3	5,941.7	5,899.0	5,686.6	3,805.4	2,569.0	2,293.0	2,352.3	2,452.7	2,482.4	2,618.1	2,831.9
L	**Firm Purchases**	667.5	614.2	583.4	575.2	564.6	498.5	445.6	442.5	402.9	385.1	382.0	358.7
&	**Non-Firm Purchases**	720.9	720.9	720.9	720.9	720.9	687.0	627.1	628.4	627.3	641.7	672.2	679.5
R	**New Resources**			66.7	323.1	2,338.4	3,765.0	4,427.3	4,438.3	4,438.3	4,533.1	4,533.1	4,533.1
	Total Resources	7,285.7	7,276.8	7,270.0	7,305.7	7,429.2	7,519.6	7,793.1	7,861.5	7,921.2	8,042.3	8,205.5	8,403.2

Case # 72

Med Load - Med Gas

Medium Environmental Adders

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	26	53	81	109	138	167	196	225	285	379	466	582
			After Conservation												
			System Load (MWa)	5,698	5,674	5,713	5,796	5,920	6,013	6,127	6,253	6,487	6,863	7,194	7,560
	0.50		Energy Sales (MWa)	5,149	5,154	5,211	5,298	5,398	5,500	5,605	5,712	5,872	6,099	6,409	6,542
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,251	9,057	10,887	13,280	14,615	14,998	14,974	14,949	14,941	15,286	15,324	15,617
			Net Conservation Assets ($M)	64	128	193	235	274	312	347	381	445	526	572	650
			Utility Cost												
52,388	3.49	Nominal	**Operating Revenues ($M)**	2,318	2,289	2,366	2,558	2,916	3,497	3,849	4,025	4,201	4,550	5,022	5,499
	0.18	Real		2,318	2,216	2,217	2,320	2,561	2,973	3,167	3,207	3,137	3,082	3,086	2,968
	2.98	Nominal	Cost in mills/kWh	51.4	50.7	51.8	55.1	61.7	72.6	78.4	80.5	81.7	85.2	89.5	96.0
	-0.31	Real		51.4	49.1	48.6	50.0	54.2	61.7	64.5	64.1	61.0	57.7	55.0	51.8
		Nominal	Average Customer Bill ($)	1,748	1,709	1,743	1,854	2,075	2,449	2,651	2,727	2,756	2,845	3,012	3,213
		Real		1,748	1,654	1,634	1,682	1,823	2,082	2,182	2,172	2,058	1,927	1,851	1,734
			Total Resource Cost												
			DSR Customer Cost ($M)	0.9	2.2	3.4	6.9	9.9	12.6	15.3	17.4	20.6	21.5	18.5	5.3
			Levelized (20-year at 8.6%)	0.1	0.3	0.7	1.4	2.5	3.8	5.4	7.3	11.5	18.4	24.8	29.5
			Energy Svc Charge ($M)	6.0	12.2	18.8	22.8	26.8	31.1	35.4	39.9	49.8	66.6	78.8	84.7
53,027	3.49	Nominal	**Total Resource Cost ($M)**	2,324	2,302	2,386	2,582	2,945	3,532	3,890	4,072	4,263	4,635	5,126	5,613
	0.18	Real		2,324	2,228	2,236	2,342	2,587	3,003	3,201	3,245	3,182	3,139	3,150	3,029
	2.81	Nominal	Cost in mills/kWh	51.3	50.5	51.5	54.6	60.9	71.3	76.8	78.6	79.3	82.1	85.6	90.6
	-0.47	Real		51.3	48.9	48.3	49.5	53.5	60.6	63.2	62.6	59.2	55.6	52.6	48.9

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 52.84

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 50.65

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Med Load - Med Gas
Medium Environmental Adders

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	49,756	49,531	49,913	50,564	51,812	52,617	53,630	54,740	56,729	59,808	66,093	65,266
	MWa	5,680	5,654	5,698	5,772	5,915	6,007	6,122	6,249	6,476	6,827	7,545	7,450
	Total Annual Emissions (1000 Tons)												
-6.27%	CO2	43,183	42,405	41,035	39,021	26,597	19,425	18,475	19,196	20,634	22,546	25,545	12,619
-6.84%	NOx	91.1	88.8	84.7	80.1	38.8	13.4	11.5	12.4	14.4	16.5	21.5	23.7
-6.92%	TSP	8.7	8.4	8.1	7.7	4.0	1.2	0.9	0.9	1.1	1.3	1.8	2.2
	Annual System Emission Rates (Pounds/MWh)												
-7.60%	CO2	1,736	1,712	1,644	1,543	1,027	738	689	701	727	754	773	387
-8.16%	NOx	3.66	3.59	3.39	3.17	1.50	0.51	0.43	0.45	0.51	0.55	0.65	0.73
-8.24%	TSP	0.35	0.34	0.32	0.30	0.15	0.05	0.03	0.03	0.04	0.04	0.05	0.07
	Emission Rates as Percent of 1994 Base												
	CO2	100	98.64	94.73	88.92	59.15	42.54	39.69	40.41	41.91	43.43	44.53	22.28
	NOx	100	97.92	92.65	86.46	40.86	13.88	11.66	12.35	13.82	15.03	17.73	19.84
	TSP	100	97.48	92.30	86.68	43.66	13.32	9.25	9.82	11.34	12.81	15.28	19.52

20 Year Emissions (1000 Tons)	Average	Total
CO2	24,956	499,113
NOx	32.3	647
TSP	2.9	59

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Med Load - Med Gas
High Environmental Adders

Incremental Summer Capacity (MW) of Resource Additions

Region	Resource	1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
OWC	DSM Programs	18.6	19.9	20.4	20.7	21.2	21.3	21.3	21.4	41.9	62.4	58.9	72.5	400.5
OWC	OWC Wind Non-Firm			23.0	23.0									46.0
OWC	OWC Wind Firm													0.0
OWC	OWC Geothermal				100.0	100.0	100.0							300.0
OWC	OWC Cogen 1					150.4	150.4							300.8
OWC	OWC Cogen 2					441.8	441.8	44.5			230.3	75.8	6.6	1240.8
OWC	OWC Combined Cycle													0.0
OWC	OWC Bridger Trans L													0.0
OWC	OWC Htr/OWC Tran L													0.0
OWC	OWC Simple Cycle CT													0.0
OWC	OWC Pump Storage													0.0
OWC	**Total**	**18.6**	**19.9**	**43.4**	**143.7**	**713.4**	**713.5**	**65.8**	**21.4**	**41.9**	**292.7**	**134.7**	**79.1**	**2288.1**
UTAH	DSM Programs	18.1	18.5	18.9	19.0	19.2	19.1	18.9	19.1	37.5	56.9	54.7	68.0	367.9
UTAH	Utah Wind Non-firm			23.0	23.0									46.0
UTAH	Utah Wind Firm			34.5	34.5									69.0
UTAH	Utah Geothermal				100.0	100.0	100.0							300.0
UTAH	Utah Cogen 1					36.7								36.7
UTAH	Utah Cogen 2					197.4	197.4							394.8
UTAH	Utah Combined Cycle					423.0	423.0	423.0	297.5	34.6	110.6	109.5	190.0	2011.2
UTAH	Utah Gadsby Repower					168.0	129.4							297.4
UTAH	Utah IGCC Hunter 4													0.0
UTAH	Utah IGCC CT													0.0
UTAH	Utah PC Hunter 4													0.0
UTAH	Utah Coal $23.25/Ton													0.0
UTAH	Utah Coal $27.00/Ton													0.0
UTAH	Utah Simple Cycle CT													0.0
UTAH	Utah Compressed Air													0.0
UTAH	Utah Pumped Storage													0.0
UTAH	**Total**	**18.1**	**18.5**	**76.4**	**176.5**	**944.3**	**868.9**	**441.9**	**316.6**	**72.1**	**167.5**	**164.2**	**258.0**	**3523.0**
WYOMING	DSM Programs	6.3	6.4	6.5	6.4	6.6	6.5	6.6	6.5	13.0	19.6	18.8	23.2	126.4
WYOMING	Wyo Wind Non-firm			23.0	23.0									46.0
WYOMING	Wyo Wind Firm			34.5	34.5									69.0
WYOMING	Wyo Combined Cycle					423.0	210.6							633.6
WYOMING	Wyo IGCC Wyodak 2													0.0
WYOMING	Wyo IGCC CT													0.0
WYOMING	Wyo PC Wyodak 2													0.0
WYOMING	Wyo Coal $6.70/Ton													0.0
WYOMING	Wyo Simple Cycle CT													0.0
WYOMING	**Total**	**6.3**	**6.4**	**64.0**	**63.9**	**429.6**	**217.1**	**6.6**	**6.5**	**13.0**	**19.6**	**18.8**	**23.2**	**875.0**
TOTAL	DSM Programs	43.0	44.8	45.8	46.1	47.0	46.9	46.8	47.0	92.4	138.9	132.4	163.7	894.8
TOTAL	Renewable			138.0	338.0	200.0	200.0							876.0
TOTAL	Cogeneration					826.3	789.6	44.5			230.3	75.8	6.6	1973.1
TOTAL	Combined Cycle CT					1,014.0	763.0	423.0	297.5	34.6	110.6	109.5	190.0	2942.2
TOTAL	Coal & IGCC													0.0
TOTAL	Transmission													0.0
TOTAL	Simple Cycle CT													0.0
TOTAL	Pumped Storage													0.0
TOTAL	**Total**	**43.0**	**44.8**	**183.8**	**384.1**	**2,067.3**	**1,799.5**	**514.3**	**344.5**	**127.0**	**479.8**	**317.7**	**360.3**	**6686.1**

Annual Summer Peak Capacity (MW)

SYSTEM L & R	1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
Native Load	7,269	7,316	7,457	7,623	7,860	7,995	8,207	8,413	8,807	9,373	10,034	10,782
Firm Sales	1,785	1,900	1,900	1,875	1,890	1,795	1,795	1,795	1,485	1,177	1,102	927
DSM Programs	(43)	(88)	(134)	(180)	(227)	(274)	(320)	(367)	(460)	(599)	(731)	(895)
Total Requirements	**9,011**	**9,128**	**9,223**	**9,318**	**9,523**	**9,516**	**9,682**	**9,841**	**9,832**	**9,951**	**10,405**	**10,814**
Existing Generation	9,441	9,983	10,146	10,170	10,185	10,201	10,208	10,208	10,123	10,014	9,869	9,843
Firm Purchases	809	758	658	638	632	607	600	579	424	424	374	341
New Resources			138	476	2,516	4,269	4,736	5,034	5,069	5,409	5,595	5,791
Summer Purch $6/Year	500	500	500									
Total Resources	10,750	11,241	11,442	11,284	13,333	15,077	15,544	15,821	15,616	15,847	15,838	15,975
Reserves	1,739	2,113	2,127	1,648	3,359	4,977	5,279	5,396	5,199	5,312	4,849	4,577
Reserve Margin (RM) (%)	19.3	23.1	24.0	21.1	40.0	58.4	60.6	60.8	58.8	59.2	52.2	47.7

Case # 73

Med Load - Med Gas
High Environmental Adders

Incremental Winter Capacity (MW) of Resource Additions

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015	Total
	DSM Programs	21.9	25.2	26.4	27.0	27.8	28.3	28.1	28.5	55.6	82.3	75.7	92.1	518.9
	OWC Wind Non-Firm			18.0	18.0									36.0
	OWC Wind Firm													0.0
O	OWC Geothermal				100.0	100.0	100.0							300.0
W	OWC Cogen 1					160.0	160.0							320.0
C	OWC Cogen 2					470.0	470.0	47.3			245.0	80.7	7.0	1320.0
	OWC Combined Cycle													0.0
	OWC Bridger Trans L													0.0
	OWC Htr/OWC Tran L													0.0
	OWC Simple Cycle CT													0.0
	OWC Pump Storage													0.0
	Total	**21.9**	**25.2**	**44.4**	**145.0**	**757.8**	**758.3**	**75.4**	**28.5**	**55.6**	**327.3**	**156.4**	**99.1**	**2494.9**
	DSM Programs	19.5	20.3	21.2	21.3	21.4	21.4	21.1	21.2	41.6	62.9	59.3	73.4	404.6
	Utah Wind Non-firm			53.0	53.0									106.0
	Utah Wind Firm			79.5	79.5									159.0
	Utah Geothermal				100.0	100.0	100.0							300.0
	Utah Cogen 1					39.0								39.0
U	Utah Cogen 2					210.0	210.0							420.0
T	Utah Combined Cycle					450.0	450.0	450.0	316.5	36.8	117.7	116.4	202.2	2139.6
A	Utah Gadsby Repower					187.2	144.1							331.3
H	Utah IGCC Hunter 4													0.0
	Utah IGCC CT													0.0
	Utah PC Hunter 4													0.0
	Utah Coal $23.25/Ton													0.0
	Utah Coal $27.00/Ton													0.0
	Utah Simple Cycle CT													0.0
	Utah Compressed Air													0.0
	Utah Pumped Storage													0.0
	Total	**19.5**	**20.3**	**153.7**	**253.8**	**1,007.6**	**925.5**	**471.1**	**337.7**	**78.4**	**180.6**	**175.7**	**275.6**	**3899.5**
	DSM Programs	5.5	5.6	5.7	5.7	5.9	6.0	6.1	6.1	12.2	18.8	18.1	22.7	118.4
W	Wyo Wind Non-firm			53.0	53.0									106.0
Y	Wyo Wind Firm			79.5	79.5									159.0
O	Wyo Combined Cycle					450.0	224.1							674.1
M	Wyo IGCC Wyodak 2													0.0
I	Wyo IGCC CT													0.0
N	Wyo PC Wyodak 2													0.0
G	Wyo Coal $6.70/Ton													0.0
	Wyo Simple Cycle CT													0.0
	Total	**5.5**	**5.6**	**138.2**	**138.2**	**455.9**	**230.1**	**6.1**	**6.1**	**12.2**	**18.8**	**18.1**	**22.7**	**1057.5**
	DSM Programs	46.9	51.1	53.3	54.0	55.1	55.7	55.3	55.8	109.4	164.0	153.1	188.2	1041.9
T	Renewable			283.0	483.0	200.0	200.0							1166.0
O	Cogeneration					879.0	840.0	47.3			245.0	80.7	7.0	2099.0
T	Combined Cycle CT					1,087.2	818.2	450.0	316.5	36.8	117.7	116.4	202.2	3145.0
A	Coal & IGCC													0.0
L	Transmission													0.0
	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**46.9**	**51.1**	**336.3**	**537.0**	**2,221.3**	**1,913.9**	**552.6**	**372.3**	**146.2**	**526.7**	**350.2**	**397.4**	**7451.9**

Annual Winter Peak Capacity (MW)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
S	Native Load	7,569	7,631	7,736	7,894	8,085	8,279	8,478	8,694	9,104	9,732	10,344	11,085
Y	Firm Sales	1,463	1,463	1,463	1,363	1,313	1,313	1,313	1,313	995	737	612	437
S	DSM Programs	(47)	(98)	(151)	(205)	(260)	(316)	(371)	(427)	(537)	(701)	(854)	(1,042)
T	Total Requirements	8,985	8,996	9,048	9,052	9,138	9,276	9,420	9,580	9,562	9,768	10,102	10,480
E													
M	Existing Generation	9,385	10,025	10,190	10,217	10,228	10,244	10,251	10,255	10,161	10,047	9,893	9,869
	Firm Purchases	963	825	830	824	799	774	769	761	319	269	269	269
L	New Resources			283	766	2,932	4,790	5,288	5,604	5,641	6,004	6,201	6,410
&	Summer Purch $6/Year												
R	Total Resources	10,348	10,850	11,303	11,807	13,959	15,808	16,308	16,620	16,121	16,320	16,363	16,548
	Reserves	1,363	1,854	2,067	2,245	4,177	5,755	6,111	6,263	5,781	5,774	5,483	5,291
	Reserve Margin (RM) (%)	15.2	20.6	24.9	30.4	52.8	70.4	73.1	73.5	68.6	67.1	62.0	57.9

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9/18/95 7:40 PM

Case # 73

PacifiCorp RAMPP-4

Med Load - Med Gas
High Environmental Adders

Cumulative Annual Energy (MWa)

		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	DSM Programs	11.3	23.4	35.9	48.6	61.6	74.8	87.9	101.1	126.9	165.5	201.8	246.5
	OWC Wind Non-Firm			26.6	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
	OWC Wind Firm				94.8	189.6	284.4	284.4	284.4	284.4	284.4	284.4	284.4
O	OWC Geothermal					148.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9
W	OWC Cogen 1					437.3	874.6	918.7	918.7	918.7	1,146.6	1,221.6	1,228.2
C	OWC Cogen 2												
	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Htr/OWC Tran L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	11.3	23.4	62.6	196.7	890.8	1,585.0	1,642.1	1,655.3	1,681.2	1,947.7	2,059.0	2,110.3
	DSM Programs	12.3	25.0	37.8	50.8	63.9	76.9	89.9	102.9	128.5	167.6	205.1	251.9
	Utah Wind Non-firm			33.4	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7
	Utah Wind Firm			50.1	100.1	100.1	100.1	100.1	100.1	100.1	100.1	100.1	100.1
	Utah Geothermal				94.8	189.6	284.4	284.4	284.4	284.4	284.4	284.4	284.4
	Utah Cogen 1					36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
U	Utah Cogen 2					195.4	390.8	390.8	390.8	390.8	390.8	390.8	390.8
T	Utah Combined Cycle					418.7	837.4	1,256.1	1,550.6	1,584.8	1,694.3	1,802.7	1,990.8
A	Utah Gadsby Repower					170.3	301.8	301.8	301.8	301.8	301.8	301.8	301.8
H	Utah IGCC Hunter 4												
	Utah IGCC CT												
	Utah PC Hunter 4												
	Utah Coal $23.25/Ton												
	Utah Coal $27.00/Ton												
	Utah Simple Cycle CT												
	Utah Compressed Air												
	Utah Pumped Storage												
	Total	12.3	25.0	121.3	312.4	1,241.0	2,094.5	2,526.1	2,833.6	2,893.5	3,042.1	3,188.0	3,422.8
	DSM Programs	4.6	9.3	14.1	18.9	23.7	28.6	33.5	38.4	48.2	63.2	77.7	95.8
W	Wyo Wind Non-firm			33.4	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7
Y	Wyo Wind Firm			50.1	100.1	100.1	100.1	100.1	100.1	100.1	100.1	100.1	100.1
O	Wyo Combined Cycle					418.7	627.2	627.2	627.2	627.2	627.2	627.2	627.2
M	Wyo IGCC Wyodak 2												
I	Wyo IGCC CT												
N	Wyo PC Wyodak 2												
G	Wyo Coal $6.70/Ton												
	Wyo Simple Cycle CT												
	Total	4.6	9.3	97.5	185.7	609.2	822.6	827.5	832.4	842.2	857.2	871.7	889.8
	DSM Programs	28.3	57.7	87.8	118.3	149.2	180.3	211.3	242.4	303.6	396.2	484.6	594.1
T	Renewable			193.5	576.6	766.2	955.8	955.8	955.8	955.8	955.8	955.8	955.8
O	Cogeneration					817.9	1,599.6	1,643.6	1,643.6	1,643.6	1,871.6	1,946.6	1,953.2
T	Combined Cycle CT					1,007.7	1,766.4	2,185.1	2,479.6	2,513.8	2,623.3	2,731.7	2,919.8
A	Coal & IGCC												
L	Transmission												
	Simple Cycle CT												
	Pumped Storage												
	Total	28.3	57.7	281.3	694.8	2,741.0	4,502.1	4,995.8	5,321.4	5,416.9	5,846.9	6,118.7	6,422.9
S	**Native Load**	5,414.1	5,416.9	5,484.3	5,595.2	5,747.9	5,870.1	6,012.8	6,168.4	6,462.6	6,932.0	7,350.6	7,832.2
Y	**Pump Storage/Peak Return**	191.6	266.0	307.2	306.6	257.0	306.3	306.7	307.0	305.0	305.0	305.0	305.0
S	**Firm Sales**	1,605.8	1,622.6	1,572.2	1,533.6	1,514.6	1,489.9	1,489.9	1,454.7	1,265.5	1,092.9	1,037.1	828.4
T	**Non-Firm Sales**						127.4	200.1	268.5	283.2	335.1	202.2	195.6
E	**DSM Programs**	(28.3)	(57.7)	(87.8)	(118.3)	(149.2)	(180.3)	(211.2)	(242.4)	(303.6)	(396.2)	(484.6)	(594.1)
M	**Total Requirements**	7,183.3	7,247.8	7,275.8	7,317.2	7,370.3	7,613.4	7,798.2	7,956.2	8,012.6	8,268.8	8,410.4	8,567.1
	Existing Generation	5,782.5	5,900.3	5,765.6	5,444.6	3,493.0	2,193.8	2,020.9	1,970.0	1,998.4	1,926.9	1,842.4	1,822.2
L	**Firm Purchases**	667.5	614.2	583.4	575.2	564.6	481.4	445.6	442.5	402.9	385.1	382.0	361.9
&	**Non-Firm Purchases**	720.9	720.9	720.9	720.9	720.9	616.3	547.1	464.7	498.0	506.0	551.8	554.2
R	**New Resources**	12.5	12.5	206.0	576.6	2,591.9	4,321.8	4,784.6	5,079.0	5,113.3	5,450.7	5,634.1	5,828.7
	Total Resources	7,183.3	7,247.8	7,275.8	7,317.2	7,370.3	7,613.3	7,798.2	7,956.2	8,012.6	8,268.8	8,410.4	8,567.0

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Case # 73

Med Load - Med Gas
High Environmental Adders

Financial Model Output for 1996-2015 (including end effects to 2045)

50-year NPV at 8.6% ($M)	50-year Annual Growth Rate (%)			1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
			System Load (MWa)	5,724	5,727	5,794	5,905	6,058	6,180	6,323	6,478	6,773	7,242	7,661	8,142
			Conservation (MWa)	28	57	87	118	149	180	211	242	304	397	485	601
			After Conservation												
			System Load (MWa)	5,696	5,670	5,707	5,788	5,909	6,001	6,112	6,237	6,469	6,845	7,176	7,541
	0.49		Energy Sales (MWa)	5,147	5,150	5,205	5,291	5,388	5,489	5,592	5,697	5,855	6,082	6,393	6,525
			Total Customers (000's)	1,326	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,525	1,599	1,667	1,712
			Net Electric Plant ($M)	8,568	9,970	12,145	14,694	16,189	16,519	16,597	16,506	16,349	16,523	16,553	16,801
			Net Conservation Assets ($M)	71	143	215	259	302	343	381	417	481	551	585	653
			Utility Cost												
55,552	3.48	Nominal	**Operating Revenues ($M)**	2,403	2,390	2,515	2,777	3,185	3,758	4,159	4,296	4,501	4,819	5,326	5,855
	0.17	Real		2,403	2,314	2,357	2,519	2,797	3,195	3,423	3,423	3,361	3,264	3,272	3,159
	2.97	Nominal	Cost in mills/kWh	53.3	53.0	55.2	59.9	67.5	78.2	84.9	86.1	87.8	90.4	95.1	102.4
	-0.32	Real		53.3	51.3	51.7	54.4	59.3	66.4	69.9	68.6	65.5	61.3	58.4	55.3
		Nominal	Average Customer Bill ($)	1,812	1,784	1,853	2,013	2,267	2,631	2,865	2,910	2,953	3,014	3,194	3,420
		Real		1,812	1,727	1,736	1,826	1,991	2,237	2,358	2,319	2,205	2,041	1,963	1,846
			Total Resource Cost												
			DSR Customer Cost ($M)	1.2	2.7	4.3	8.4	12.0	15.4	18.8	21.7	25.7	27.2	24.7	12.4
			Levelized (20-year at 8.6%)	0.1	0.4	0.9	1.8	3.0	4.7	6.7	9.0	14.2	22.9	31.2	38.8
			Energy Svc Charge ($M)	6.8	14.0	21.5	25.9	30.5	35.2	40.0	45.1	55.5	72.4	83.7	86.9
56,276	3.47	Nominal	**Total Resource Cost ($M)**	2,410	2,404	2,537	2,804	3,218	3,798	4,206	4,350	4,571	4,914	5,441	5,980
	0.17	Real		2,410	2,328	2,378	2,544	2,826	3,229	3,461	3,466	3,413	3,328	3,343	3,227
	2.80	Nominal	Cost in mills/kWh	53.2	52.8	54.8	59.3	66.5	76.7	83.0	83.9	85.1	87.0	90.9	96.5
	-0.49	Real		53.2	51.1	51.4	53.8	58.4	65.2	68.3	66.9	63.5	59.0	55.8	52.1

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.30% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 56.16

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 53.76

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Med Load - Med Gas
High Environmental Adders

Net System Projected Emissions

Annual Growth Rate		1996	1997	1998	1999	2000	2001	2002	2003	2005	2008	2011	2015
	System Energy												
	GWh	48,859	49,277	49,964	50,664	51,296	52,525	53,508	54,601	56,624	59,925	66,076	65,747
	MWa	5,578	5,625	5,704	5,784	5,856	5,996	6,108	6,233	6,464	6,841	7,543	7,505
	Total Annual Emissions (1000 Tons)												
-14.38%	CO2	42,440	41,452	38,694	35,625	23,920	16,131	15,749	15,973	16,958	18,603	20,301	2,221
-14.93%	NOx	88.9	86.1	78.8	72.2	32.9	6.5	6.5	5.7	6.1	6.0	6.3	4.1
-12.55%	TSP	8.4	8.2	7.6	7.0	3.1	0.7	0.5	0.5	0.5	0.5	0.6	0.7
	Annual System Emission Rates (Pounds/MWh)												
-15.71%	CO2	1,737	1,682	1,549	1,406	933	614	589	585	599	621	614	68
-16.24%	NOx	3.64	3.49	3.16	2.85	1.28	0.25	0.24	0.21	0.21	0.20	0.19	0.13
-13.91%	TSP	0.35	0.33	0.31	0.28	0.12	0.03	0.02	0.02	0.02	0.02	0.02	0.02
	Emission Rates as Percent of 1994 Base												
	CO2	100	96.84	89.16	80.95	53.68	35.36	33.89	33.68	34.48	35.74	35.37	3.89
	NOx	100	95.93	86.67	78.25	35.23	6.77	6.72	5.75	5.90	5.45	5.27	3.45
	TSP	100	96.62	88.52	79.76	35.36	7.57	5.64	5.09	5.30	5.31	5.26	5.81

20 Year Emissions (1000 Tons)	Average	Total
CO2	20,639	412,781
NOx	22.3	446
TSP	2.2	43

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