PACIFICORP

RESOURCE AND MARKET PLANNING PROGRAM

RAMPP - 5

DECEMBER - 1997

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Executive Summary

PacifiCorp's RAMPP-5 Report covers its long-range Integrated Resource Planning (IRP) process. The major finding in the company's fifth Resource and Market Planning Program is that PacifiCorp does not need to make any new resource acquisition decisions during the next several years. However, the company will continue to support ongoing Demand Side Management (DSM) programs, implement cost-effective system improvements, and take advantage of resource acquisition opportunities that cost effectively meet the future needs of the company.

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. PacifiCorp implemented two significant changes in assumptions in preparation of the new RAMPP-5 base case. The first change reduced the load forecast to allow for loss of regulated load anticipated with the coming of open access and competition. The second change increased anticipated purchased power to achieve a balancing between wholesale purchases and sales by the fifth year of the planning cycle.

Major changes are occurring in the industry. The report discusses the following: opening the entire state of California to direct access beginning January 1, 1998, increasing activity on the transition to an open competitive marketplace, greater resolution of the FERC NOPR rules, continued progress on IndeGO, and resolution of the Centralia plant's emission issues.

The RAMPP-5 documents include the main report and an appendix with model output results from the sensitivities. Those sensitivities used the RAMPP-4 Update base case assumptions. A major innovation in the RAMPP-5 Report is the use of a sweeps approach for most of the sensitivities. Each sweep included up to 16 sensitivities, whereby the company varied one factor in small increments to better understand how variation in that factor can affect planning issues. The sensitivities included sweeps of gas and wholesale market prices, load change, environmental adders, and several other smaller issues.

The results from the sensitivities were consistent with results from sensitivities run in RAMPP-3 and RAMPP-4. The continuing conclusions are as follows:

- The least-cost supply-side resource choice continues to be gas-fired plants (it was coal-fired in RAMPP-3 and gas-fired in RAMPP-4 and in the RAMPP-4 Update),
- Modest amounts of DSM are cost effective relative to plant operating costs and market prices,
- Renewables are not cost effective compared to gas-fired resources,
- Expanding transmission capacity is not a cost effective choice at this time,
- Load growth does not lead to higher prices for customers,
- Higher gas prices do not lead to higher prices for customers because of two factors -- PacifiCorp's activity in the wholesale market and a linkage between gas prices and wholesale market prices,
- Environmental adders would result in significantly higher prices for customers (real levelized customer prices would be 30 percent higher at a $40/ton adder for carbon dioxide).

PacifiCorp is on track for achieving all of the items in the RAMPP-4 and RAMPP-4 Update action plan. The company has made good progress in achieving its objectives in demand-side management; it has used the market for acquisition of peaking resources, it has made improvements in system efficiency, it has participated in development of the Foote Creek Wind project; it has monitored global climate science, carbon offsets, solar resources, and clean coal technologies, and it has been actively involved in the competitive marketplace.

The company anticipates that as open access continues to affect more of the states in which it serves, that IRP will continue to change. The traditional model of IRP does not fit well with a competitive environment. As the company operates in an increasingly competitive environment, its planning will continue to evolve.

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Chapter 1: Introduction

This document reports on PacifiCorp's fifth Resource and Market Planning Program (RAMPP-5) cycle, the company's Integrated Resource Planning (IRP) process. PacifiCorp completed its fourth IRP cycle, RAMPP-4, in November 1995, and an Update to that report in November 1996.

The IRP reports document 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 needs, and the need for new resources, including new power plants, power purchases, and customer efficiency programs.

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 IRP 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. 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, power sources, and the environment in which the company operates.

RAMPP provides a long-range look at the company's load and resource position, identifies risks and strategies that merit additional analysis, and provides a framework for the analysis of specific resource opportunities. This analysis requires an understanding of the changes occurring in the electric utility industry.

Change continues to drive the electric utility industry. As noted in the company's annual report issued in April 1997, two issues challenged the company through 1996: continued uncertainty about the outcome of electric utility restructuring, and concern about what part PacifiCorp will play in the convergence of the electric and gas industries. These same uncertainties continue to challenge the company's planning efforts today. The next chapter on Regulatory Requirements addresses the challenge the company faces in fitting its planning into an IRP model that was developed during a more predictable time in the industry.

IRP Assumptions

PacifiCorp believes it is appropriate to begin implementing modifications of IRP assumptions to more closely match the realities under which utilities now operate. Two key areas for PacifiCorp are load forecasting and wholesale transactions.

PacifiCorp believes it will lose some of its existing regulated load as open access occurs in more of the states in which it operates. Open access will occur in California starting January 1,1998, and soon thereafter in Montana. Within five years, the company believes it will lose at least 10 percent of its current regulated retail load. The company's market research shows that customers will switch providers for only a very small price differential, as small as 2 percent. Several studies indicate the company could lose significant regulated load as open access spreads.

The company does not believe it is reasonable to plan for and build resources for load which it expects to lose within the next five years. Therefore, the company is adjusting its load forecast used in the model inputs for the new RAMPP-5 base case to reflect this expectation. The net effect on the company may be negligible, because open access will bring new customers. However, the company will not have an obligation to serve the load of those new customers, so IRP is not the best model for planning for the competitive load. Another way to think about customers' loads in a competitive world is that customers will have the ability to choose their supplier. With an ability to choose, the utility will not have the same obligation toward those customers as it had in a fully regulated environment.

The second key adjustment that the company has made for the new RAMPP-5 base case is in the area of wholesale contracts. Wholesale sales have become an increasing part of PacifiCorp's revenues. They accounted for 25 percent of total revenues in 1996. The company does not include wholesale sales and purchases of less than one year in its resource planning. However, wholesale sales and purchases of more than one year are part of the load and resource mix. Because of this, temporary imbalances in wholesale sales versus purchases can have a dramatic impact on planning. For example, two years ago the company signed a long-term peaking contract for winter capacity with Southern California Edison. This met winter peaking needs but did not address summer peaking needs. As a result, the company's peaking needs switched from winter to summer. If instead the company had signed a long-term peaking contract for summer capacity, the company's peaking needs would have remained in the winter.

Therefore, the company is making an adjustment in the RAMPP-5 base case. This adjustment will remove the impact of these temporary imbalances on planning, and it will more closely reflect the company's strategy of relying increasingly on the wholesale market to acquire the resources needed to meet the commitments made in long-term wholesale sales contracts. The adjustment increases the amount of short-term wholesale purchases made in each of the first five years of the planning horizon to achieve a balance between wholesale sales and wholesale purchases by the fifth year. This adjustment has the effect of removing the impact of wholesale transactions on IRP modeling.

PacifiCorp believes it has the ability to handle that volume of purchases on its system, and believes there will be sufficient availability of market resources during this time period. The company is currently managing about 5,600 MW in purchases. To achieve the wholesale balancing would require at most an additional 1,800 MW. That would be only about 30 percent of what the company is currently purchasing. The company's transmission, scheduling personnel, and control area personnel are sufficient for that additional volume of activity.

The region is showing approximately a 1.9 percent annual load growth over the next ten years, according to the Western System Coordinating Council (WSCC). The region's reserve margin will not get as low as 15 percent until around 2004-2006. The perception in the region is that there is still a fairly large reserve margin available in the marketplace to support purchases throughout the WSCC. This does not include planned additions. The company believes the timing of those additions will be driven by when the market is ready for the added resource. There are numerous developers who are only waiting for market prices to show some indication that they can support additional resources.

These two adjustments are the first steps in reflecting realistic expectations in the IRP process. The company anticipates that additional adjustments could be necessary as all of the affected parties better understand the implications of a more competitive market for the electric utility industry.

Significant Events

The RAMPP-4 Update Report discussed significant events in 1996 that had an effect on PacifiCorp's planning. These demonstrated the changing nature of the industry and the need for planning flexibility:

- 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 transmission system,
- Negotiation of emission reductions at the Centralia plant,
- The Northwest Comprehensive Review, and
- California restructuring.

Significant events in 1997 included continuing issues from 1996. The text below discusses each of the following:

- Opening the entire state of California to direct access beginning January 1, 1998,
- Increasing activity on the transition to an open competitive marketplace,
- Greater resolution of the FERC NOPR rules,
- Continued progress on IndeGO,
- Resolution of the Centralia plant's emission issues, and
- Increased concern about Global Warming.

Opening the state of California to direct access beginning January 1, 1998

Effective January 1, 1998, all consumers in the state of California will have direct access to the energy supplier of their choice. They will continue to receive transmission and distribution service through their utility distribution company. PacifiCorp has approximately 40,000 customers in northern California. The company is actively preparing for the January 1 deadline, when a host of procedures must be ready for customers who decide to sign up for direct access. California will give the company experience with direct access in a better way than a pilot program. The limited nature of a pilot program also limits the lessons to be learned.

Increasing activity on the transition to an open competitive marketplace

Electric utilities are one of the few remaining regulated industries in the United States. Regulation of the electric utility industry is changing due to competitive forces and governmental actions, both at the federal and state levels. Federal and state legislatures and state regulatory authorities are addressing the issues associated with a transition to competition.

Both residential and business customers are now beginning to experience choice in a wide range of electric services. Already the company sees increases in advertising and marketing by alternative energy suppliers. Large industrial customers are actively seeking choice of suppliers, and have options to build their own generation or cogeneration, or to use alternative energy sources, such as natural gas. Other consumers also have the option to switch energy sources, and to consider alternatives such as municipalization. Open access will be coming to increasing portions of the company's service territory: California in 1998, Montana shortly thereafter, and other states will soon follow.

PacifiCorp wants the transition to an open, competitive marketplace all across the country completed by the end of 2001. The company recognizes that states need implementation flexibility, but the company is advocating federal legislation to ensure consistency.

Developments in this transformation to increased competition have been largely dependent on state legislative and regulatory initiatives and vary considerably from state to state. Industry restructuring bills range from those which require study of direct retail access to those which would result in implementation of direct access for retail customers.

So far eight states have enacted legislation that establishes a date for retail wheeling:

California	Maine
Montana	Nevada
Oklahoma	Pennsylvania
New Hampshire	Rhode Island

Regulatory commissions in an additional eight states have issued orders or final guidelines on restructuring:

Arizona	Massachusetts
Michigan	New Jersey
New York	Texas
Vermont	Wisconsin

Commissions in the following ten states have issued reports on restructuring:

Arkansas	Colorado
Connecticut	Idaho
Kansas	Minnesota
North Carolina	Virginia
Washington	West Virginia

Commissions in the following 22 states and the District of Columbia have opened investigations on restructuring:

Alaska	Delaware
District of Columbia	Florida
Georgia	Hawaii
Illinois	Indiana
Iowa	Louisiana
Maryland	Minnesota
Mississippi	Missouri
Nebraska	New Mexico
North Dakota	Ohio
Oregon	South Carolina
South Dakota	Utah
Wyoming	

There are only two states where no action on restructuring is taking place:

Alabama	Tennessee

The following tables provides a state-by-state summary of open access activities, first for the states in PacifiCorp's existing service territory, and then for the other 43 states.

State Summary of Open Access
In PacifiCorp's Existing Service Territory

	Pilot Programs	Legislation and Commission Activity on Retail Access
CA	No pilot programs will be planned.	• Enacted legislation allows full open access for all customers on 1/1/98.
ID	Pilot programs have been approved.	• No restructuring legislation has been introduced, but a study bill has been enacted. • The commission has issued an order in restructuring, and the utilities must make a filing.
MT	Pilot programs will be allowed.	• Enacted legislation requires access to be phased in beginning on 7/1/98.
OR	PGE's pilot was approved in 10/97.	• Legislation on restructuring has been introduced, but not enacted. • The commission has began to review restructuring.
UT	No pilot programs have been approved.	• Restructuring legislation has not been enacted, but legislation was enacted to create a task force to study the issue and report to the legislature in November. • The commission has also began to review restructuring.
WA	Pilot programs have been approved.	• Legislation has been introduced, but not enacted. • The commission has opened an investigation on restructuring issues.
WY	No pilot programs have been planned.	• Restructuring legislation has not been enacted, but a study committee was established by the legislature. • The commission is conducting an economic study on restructuring issues.

State Summary of Open Access in Other States

	Pilot Programs	Legislation and Commission Activity on Retail Access
AL	No pilot programs have been planned.	• Restructuring legislation was introduced but not enacted. • The commission has not reviewed restructuring.
AK	No pilot programs have been planned.	• No restructuring legislation has been introduced. • The commission has not reviewed restructuring.
AZ	No pilot programs will be planned.	• The commission has issued rules that call for a four year phase-in of access to begin 1/1/99.
AR	No pilot programs have been planned.	• Restructuring legislation was introduced but not enacted, a study bill has been adopted. • The commission is reviewing utility restructuring plans.
CO	No pilot programs have been planned.	• Restructuring legislation was introduced but not enacted. • The commission has done a survey on restructuring issues.
CT	No pilot programs have been planned.	• Restructuring legislation was introduced but not enacted. A task force has issued a report to the legislature. • The commission has conducted two investigations on restructuring issues.
DE	No pilot programs have been planned.	• No restructuring legislation has been introduced. • The commission has opened an investigation into restructuring.

State Summary of Open Access in Other States

	Pilot Programs	Legislation and Commission Activity on Retail Access
DC	No pilot programs have been planned.	• No restructuring legislation has been introduced. • The commission opened an inquiry into restructuring.
FL	No pilot programs have been planned.	• No restructuring legislation has been introduced. • The commission has established a work group to study restructuring issues, but no formal investigation.
GA	No pilot programs have been planned.	• No restructuring legislation has been introduced. • The commission has conducted workshops on restructuring issues.
HI	No pilot programs have been planned.	• Restructuring legislation has been introduced in past sessions, but was not enacted. • The commission has held informal sessions on restructuring.
IL	Pilot programs have been introduced.	• Restructuring legislation has been introduced but not enacted. • The commission approved a pilot, but is waiting for legislation before continuing on restructuring.
IN	No pilot programs have been planned.	• Restructuring legislation was introduced, but was amended to a study bill before it was adopted. • The commission has issued a report to the legislature on restructuring issues.
IA	No pilot programs have been planned.	• No restructuring legislation has been introduced. • The board issued final guidelines for restructuring, and then decided to continue to study the issue.

State Summary of Open Access in Other States

	Pilot Programs	Legislation and Commission Activity on Retail Access
KS	No pilot programs have been approved.	• Restructuring legislation was introduced but not enacted, however, legislation to study restructuring has been enacted. • The commission has started an investigation into restructuring issues.
KY	No pilot programs have been planned.	• No restructuring legislation has been enacted. • The commission has held only informal discussions on restructuring.
LA	No pilot programs have been planned.	• No restructuring legislation has been enacted, but a study committee was established. • The commission has adopted principles to be used in studying restructuring issues.
ME	No pilot programs have been planned.	• Restructuring legislation was enacted on 5/29/97, calling for customer choice beginning 3/01/00. • The commission has made recommendations to the legislature.
MD	No pilot programs have been planned.	• No restructuring legislation has been enacted, but a legislative task force is studying restructuring and will issue a report in 12/97. • The commission has opened an investigation on restructuring issues.
MA	Pilot programs have been approved.	• Restructuring legislation has been introduced, but not enacted. • The commission has approved an agreement that will allow New England Electric System to begin access in 1/98.
MI	Pilot programs have been approved.	• No restructuring legislation has been introduced, but the governor has made recommendations. • The commission has issued a staff report.

State Summary of Open Access in Other States

	Pilot Programs	Legislation and Commission Activity on Retail Access
MN	No pilot programs have been planned.	• Restructuring legislation has not been enacted. • The commission has issued steps for restructuring.
MS	No pilot programs have been planned.	• Legislation on restructuring has not been enacted. • The commission is conducting a study.
MO	Pilot programs have been approved.	• Legislation has been introduced, but not enacted. • The commission has established a task force to study the issue.
NE	No pilot programs have been planned.	• A study bill has been proposed, and a committee has been established to evaluate competition. • The commission is conducting an economic study.
NV	No pilot programs have been planned.	• Legislation was enacted in 7/97, calling for direct access for all customers beginning 12/31/99.
NH	Pilot programs have been approved.	• Enacted legislation requires access for all customers by 7/1/98.
NJ	Pilot programs have been approved.	• Restructuring legislation has been introduced, but not enacted. • The commission has issued a restructuring plan.
NM	Pilot programs have been approved.	• Restructuring legislation has not been enacted. • The commission and Texas-New Mexico Power have reached an agreement, and access could be phased in beginning in 1997 and be completed by 2000.
NY	Pilot programs have been approved.	• The commission has reached settlements with utilities for access to be phased in beginning 1998.

State Summary of Open Access in Other States

	Pilot Programs	Legislation and Commission Activity on Retail Access
NC	No pilot programs have been planned.	• Restructuring legislation has been introduced, but not enacted. A legislative committee has been established to study restructuring issues. • The commission has placed the issue on hold for the time being.
ND	No pilot programs have been planned.	• Restructuring legislation has been introduced, but not enacted. However, a study bill has been enacted. • The commission has also began to review restructuring.
OH	No pilot programs have been planned.	• Restructuring legislation has been introduced, but not enacted. There is a legislative study committee for restructuring issues. • The commission has began some discussions, but no formal study.
OK	No pilot programs have been planned.	• Enacted legislation requires full access to be complete by 7/1/02.
PA	Pilot programs have been approved.	• Enacted legislation requires access to be phased in beginning 1/1/99.
RI	No pilot programs have been planned.	• Enacted legislation requires access will be phased in beginning 7/1/97.
SC	No pilot programs have been planned.	• Restructuring legislation has been introduced, but not enacted.
SD	No pilot programs have been planned.	• No legislation has been introduced. • The commission has informally been reviewing activities from other states, but has taken no action.
TN	No pilot programs have been planned.	• No legislation has been introduced.

State Summary of Open Access in Other States

	Pilot Programs	Legislation and Commission Activity on Retail Access
TX	No pilot programs have been approved.	• Restructuring legislation has been introduced, but not enacted. • The commission has issued a comprehensive study on restructuring.
VT	No pilot programs have been planned.	• Restructuring legislation has been introduced. • The commission has issued a report on restructuring, and the utilities are filing plans.
VA	No pilot programs have been planned.	• The legislature has not enacted restructuring legislation but has established a sub-committee. • The commission has opened an investigation on restructuring.
WV	No pilot programs have been planned.	• Legislation on restructuring has not been enacted. • The commission has opened an investigation on restructuring issues.
WI	No pilot programs have been planned.	• Restructuring legislation has not been enacted. • The commission has adopted a restructuring plan.
FED	No national pilot programs have been planned.	• Several pieces of major restructuring legislation have been recently introduced, and several more are expected in near future.

This pattern of activity shows a consistent trend toward increasing attention to competition and direct access. The company believes IRP needs to adapt to this changing reality. The next chapter on regulatory requirements addresses the ways in which IRP needs to change.

Greater Resolution of the FERC NOPR Rules

In 1995 the Federal Energy Regulatory Commission (FERC) conducted hearings and technical conferences to discuss the concept of non-discriminatory open-access transmission. As part of a Notice of Proposed Rulemaking (NOPR), this was an effort to open the nation's transmission system to all potential electric suppliers.

In 1996 the FERC issued Order 888/889 requiring public utilities to:

- File Pro-Forma Open-Access Transmission Tariffs with the FERC. Under these tariffs, public utilities are to make their transmission system available to all other electric suppliers.

- Operate an Internet web site named "Open Access Same-Time Information System" (OASIS) providing publicly available information on transmission systems.

- Conduct future transmission business separate from the power sales business in accordance with a set of rules and regulations referred to as the "Standards of Conduct."

In addition, Order 888/889 provided the following:

- Guidelines for establishing a FERC/state jurisdictional line for facilities used in unbundled retail wheeling transactions.

- Guidelines for the recovery of stranded costs.

- Guidelines for the establishment of Independent System Operators (ISO). An ISO would function as an independent operator of transmission facilities not affiliated with energy suppliers.

PacifiCorp is in compliance with the FERC's Order 888/889 requirements. On July 3, 1996, PacifiCorp filed with the FERC its Pro-Forma Open-Access Transmission Tariff. This tariff has been accepted by the Commission and was designated as PacifiCorp's FERC Electric Tariff, Original Volume No. 11. PacifiCorp currently provides firm and non-firm transmission service to more than 50 transmission customers under this tariff. In late 1996 PacifiCorp's OASIS became operational and on December 31, 1996, PacifiCorp filed its Standard of Conduct implementation procedures with the FERC.

Additionally, PacifiCorp is working collectively with federal and state legislators, as well as federal and state regulatory staff, environmental groups and customer groups to lay the groundwork for future retail wheeling.

One result of Order 888/889 is that PacifiCorp's power supply business can now use the majority of the nation's transmission system. PacifiCorp may use other utilities' OASIS sites to gather transmission information.

The FERC's Standards of Conduct protects the company from discriminatory treatment by transmission owning utilities.

On June 25, 1997, the FERC accepted PacifiCorp's filing of its market based wholesale sales tariff. The company expects only minimal review by the FERC. All future wholesale sales of PacifiCorp will be conducted in accordance with this tariff.

Continued progress on IndeGO

On July 1, 1996, PacifiCorp, in a joint effort with eight other transmission owning utilities, signed a Memorandum Of Understanding (MOU) to work towards the creation of an independent system operator called Independent Grid Operator (IndeGO). As of November 1, 1997, 21 entities had signed the MOU. They are listed below:

Investor Owned

Idaho Power Company
PacifiCorp
Public Service Company of Colorado
Sierra Pacific Power
West Plains Energy
Montana Power Company
Portland General Electric
Puget Sound Energy
Washington Water Power

Cooperatives

Basin Electric Power
Northern Lights

Publicly Owned

Chelan County PUD
Grant County PUD
Seattle City Light
Tacoma City Light
City of Colorado Springs
Platt River Power
Snohomish PUD

Federally Owned

Bonneville Power Administration
Western Area Power Administration – Loveland
Tri-State G&T

The goal of the IndeGO implementation task force is to develop an independently functioning transmission system operator for the high-voltage transmission systems of electric utilities located in the Pacific Northwest and adjacent states (Washington, Oregon, Idaho, Montana, Nevada, Utah, and Wyoming). IndeGO is intended to assure non-discriminatory, open access to electric transmission facilities, in compliance with Federal Energy Regulatory Commission (FERC) rulings.

Resolution of the Centralia plant's emission issues

A Collaborative Decision-Making (CDM) group worked since January 1996 to find ways to reduce emissions from the Centralia plant. The target emission levels are far below the limits ordered by the state of Washington in 1995. The CDM group wanted to maximize the reduction of Centralia SO_2 emissions, preserve jobs, the local economy, and tax revenues to state and local governments. The option selected was to build two wet-limestone scrubbers that may allow the plant and mine to remain open at current employment levels. This is a more expensive option to the plant owners than closing the mine and laying-off 510 employees. This solution, which includes a tax break for the plant, also allows Centralia to continue to provide 1,340 MW into population areas west of the Cascade Mountains. Since western Washington is nearly always energy deficient, the loss of this project would place further burdens on the transmission system which brings electricity over the Cascade range.

Increased Global Warming

Scientists understand more and more about the intricate relationship between the earth's climate and greenhouse gases, but are still debating many complex issues. Particularly thorny are predicting the timetable of climate changes due to manmade carbon dioxide (CO_2) emissions and forecasting the magnitude of these changes.

In the midst of this debate, PacifiCorp believes the company's best contribution is to develop innovative and cost-effective methods that address this public issue. Actions taken anywhere to reduce CO_2 emissions benefit the entire global system. Manmade CO_2 emissions are produced primarily by cars, energy and industry. Developing the best methods to address climate change will mean looking around the world for opportunities in the automobile, power and manufacturing sectors to offset CO_2 emissions.

For several years, PacifiCorp has been using pilot projects to investigate effective ways to offset CO_2 emissions worldwide. In the fall of 1997, PacifiCorp used this experience to launch a major expansion of the company's efforts, four technologically sound and cost effective initiatives:

- Providing $1.7 million to a forest preservation project in Bolivia that reduces CO_2 emissions by preventing logging and clearing.

- Launching Earth Stewards, which provides grants for community projects that clean the air and improve the environment.

- Helping scientific experts measure and document the benefits of forestry projects designed to reduce or offset CO_2 emissions.

- Participating with a broad spectrum of organizations and policy makers to develop a framework for measuring CO_2 mitigation programs and trading credits earned for those programs.

These initiatives are part of PacifiCorp's comprehensive strategy to reduce CO_2 emissions. Our efforts also include conservation and development of renewable energy. PacifiCorp launched the largest wind project in the West (outside of California) and has geothermal and solar projects. In addition, PacifiCorp and the city of Klamath Falls, Oregon, are developing a gas-fired cogeneration project that will offset CO_2 emissions by 35 percent, the highest level of offsets ever obtained for a fossil-fueled electricity plant. PacifiCorp also supports research in promising technologies that could offset or reduce CO_2 emissions.

The remainder of this report covers the essential elements of IRP. Chapter 2 reviews regulatory requirements for IRP. Chapter 3 provides a full discussion of the sensitivities performed for RAMPP-5. These sensitivities were performed in early 1997 and used the RAMPP-4 Update base case, consistent with the new sequencing of activities for IRP as outlined in Chapter 2. Chapter 4 identifies the updated inputs for the new RAMPP-5 base case. Chapter 5 provides the results of the modeling of the new RAMPP-5 base case and a comparison of it to the RAMPP-4 Update base case. Chapter 6 consists of the new RAMPP-5 action plan, developed from the results of the sensitivities and the RAMPP-5 base case. The last chapter discusses the company's performance on the RAMPP-4 action plan, as revised in the RAMPP-4 Update.

Another document, the Technical Appendix, provides detailed results for each of the cases included in the sensitivity analyses performed. Chapter 3 describes these cases.

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-5 from the RAMPP-4 acknowledgment reviews by the Oregon, Montana, and Utah Commissions and the company's response to each requirement. Because the company faces a challenge in fitting its planning into an IRP model that was developed during a more static time in the industry, this chapter includes a discussion of how IRP could evolve as the industry and regulation change. The final section reviews the public advisory process the company used in developing the study plan, inputs, and analyses for this report.

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,
- Consider the goal of IRP to 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 functions. They include integrated resource planning, demand-side policy and planning, fuel supply, generation engineering and planning, transmission engineering and planning, distribution engineering and planning, load forecasting, financial planning, regulation, government affairs, retail marketing and sales, and wholesale marketing and sales. These groups confer with other groups in the company when they need additional information and when developing or updating information to ensure coordination among all groups who rely on the same or similar information.

Requirements for RAMPP-5 From RAMPP-4 Acknowledgment Reviews

This discussion describes the specific recommendations from each commission, and the company's response to each recommendation. Three of the states in which PacifiCorp has service territory have issued orders acknowledging RAMPP-4 that contain requirements for RAMPP-5: Oregon, Montana, and Utah. Following are those requirements and the company's response to each:

The Oregon Public Utility Commission issued its acknowledgment order on RAMPP-4 on June 18, 1996.

> Oregon Requirement: For RAMPP-5, Staff requests that Pacific discuss the status of its hydro relicensing efforts with FERC. The discussion should include environmental and operational uncertainties as they related to the North Umpqua and other Pacific hydro facilities (e.g., Klamath projects).
>
> Response: PacifiCorp is actively relicensing 11 hydroelectric projects at this time. Within the next three years, the company will begin federal relicensing activities for two more hydro projects. The company's goal in hydro relicensing is to resolve project operational and environmental issues before filing federal license applications with FERC in order to reduce subsequent licensing costs and increase the certainty of a desired licensing outcome from FERC. This is being done through collaborative consultation with state and federal resource agencies, tribes and stakeholder groups. Additionally, this strategy promotes better relations with agencies, tribes and groups who will also be involved in the implementation and compliance activities associated with a new license.

The license application for the North Umpqua Project was submitted to FERC in January, 1995. Since that time the company has used a collaborative process to seek closure to certain critical environmental resource issues that were unresolved at the time the company filed the application with FERC. By the end of 1997, the company expects successful resolution of these resource issues to the satisfaction of state and federal resource management agencies.

The Klamath River project relicensing will begin several years before FERC requirements because of the complexity of the project, the multiple state jurisdictions, competing demands for water, Endangered Species Act issues, agricultural interests, power generation, and tribal issues.

The company is currently working to resolve issues associated with its Condit project. It is a 14.7 MW hydro project on the White Salmon River in Southwest Washington, built in 1913. Its 125-foot high dam has no provision for fish passage. FERC's final environmental impact statement for Condit relicensing requires $28 million in fish ladders and screens. A recent study indicated it could take from $14 to $37 million to remove the dam. The company needs to consider the cost of replacement power, plus the loss of revenues from not generating power from Condit. The company has asked FERC to temporarily halt licensing proceedings and not issue a new license for Condit. The company would prefer to find an option between FERC's requirements and dam removal. If PacifiCorp and interested parties come up with an alternative method of operating the project, that proposal would need FERC's approval, as would a proposal to remove the dam.

<u>Oregon Requirement</u>: Staff recommends that in RAMPP-5 Pacific more completely analyze the future power market and the resulting implication regarding acquisition of supply-side resources.

<u>Response</u>: The company recognizes the uncertainty of future wholesale power availability and price. For example, if all the utilities in the region plan on using the wholesale market for their future power supplies, the question arises as to where all this power is to come from after the region reaches load/resource balance. However, given the sometimes rapid changes in price on the wholesale market, it is very difficult to accurately anticipate future prices. The sensitivities performed for this report address

this issue by examining the planning implications of alternative natural gas and wholesale market price levels.

Oregon Requirement: [Pacific should] provide detailed technical information for Demand Side Management (DSM) that facilitates comparisons with similar work performed by the Northwest Power Planning Council.

Response: PacifiCorp believes it is providing the information requested during the course of the public advisory group DSM subgroup meetings. If any party has not been able to obtain the level of detailed DSM information it desires, the company is willing to work with them through the DSM subgroup process.

The Montana Public Service Commission issued its RAMPP-4 acknowledgment order on September 4, 1996.

Montana Requirement: PacifiCorp should continue its RAMPP process and make it as transparent as possible to its customers, regulators and the public.

Response: The company continues to make information available to all interested parties. Before each meeting of the public advisory group, the company provides a mailing to all members and to other parties who have expressed an interest in the company's IRP. Because of the nature of corporate decision making in a competitive industry, the company cannot make public, nor discuss with its public advisory group, all of the considerations for all of its corporate decisions.

Montana Requirement: If PacifiCorp becomes serious about acquiring a new resource, other than DSM, within its three year action plan period, the Company should inform the Commission and evaluate the impacts of acquiring the resource on the action plan.

Response: As soon as possible, the company informs each of the commissions of major resource acquisition decisions. The company also reviews the potential impact of any such decision on the current RAMPP action plan.

Montana Requirement: PacifiCorp should re-evaluate the appropriateness of its action plan in light of any significant federal or state actions that may impact industry structures (e.g., FERC Order 888).

Response: Since the current action plan from RAMPP-4, and as revised for the RAMPP-4 Update, includes DSM, a small amount of renewables, and watching the market for opportunities, the company does not believe that recent federal or state decisions merit changing the action plan at this time.

Montana Requirement: PacifiCorp should communicate to the Commission any intentions to change the RAMPP-4 DSM targets and should re-evaluate the action plan in light of the new DSM targets.

Response: The purpose of the RAMPP-4 Update was to update inputs and re-evaluate the cost effective amount of DSM. The company believes that the RAMPP-4 Update met the goals of this requirement.

Montana Requirement: The Commission agrees with DEQ that PacifiCorp should include in its next plan a more detailed cost analysis and discussion of potential efficiency improvements to thermal and hydro plants and to transmission and distribution systems.

Response: The company uses the most current avoided costs in evaluating potential efficiency improvements to thermal and hydro plants and to transmission and distribution systems. At the time that the company is considering a capital expenditure, it looks at the most current information on gas prices, wholesale market prices, capital costs, and alternative uses for that capital. The static nature of the IRP process makes it an inadequate vehicle for these analyses.

Montana Requirement: PacifiCorp should also re-evaluate with its advisory group the way it models transmission constraints.

Response: For the RAMPP-4 Update, the company evaluated with its advisory group the transmission constraints used in modeling. The company reviewed those constraints again with the advisory group in its discussions of updating the model for the new RAMPP-5 base case. As a result of this re-evaluation, the company has expanded its transmission modeling within its IRP modeling process.

The Utah Public Service Commission issued their acknowledgment order for RAMPP-4 on January 13, 1997.

Utah Requirement: The [RAMPP-5] study should break the assumed link between wholesale prices and gas prices.

Response: The company performed several sensitivities, included in this report, which break the link between wholesale prices and gas prices.

Utah Requirement: [The RAMPP-5 study] should include gas shock scenarios where the price of gas increases dramatically in a short time, and then stabilizes at the higher level.

Response: The company performed two sets of gas-price shock sensitivities for this report, one with a gas price shock in 1998 and one with a gas price shock in 2003.

Utah Requirement: The Commission finds that the IRP should include comprehensive risk analysis, identifying the elements of risk the company faces, an appraisal of the inter-relationships between those risk elements and some attempt to quantify the risks associated with different strategies that the company is investigating.

Response: The results of the new RAMPP-5 base case indicate that the company will not need new resources until the year 2012. Given lead times for gas-fired resources of three or four years, and of coal resources of seven years, the company does not need to make any new resource decisions for several years. Any short-term capacity needs will be met by purchasing off the market. One risk the company faces are potential federal action on environmental issues, especially CO_2 related to global climate concerns. As discussed in the section on the environmental adder sensitivities, the company believes federal action will include consideration of both offsets and a trading mechanism. Both of these strategies would keep costs to customers well below those of a $10/ton adder. Other resource planning risks involve the nature of the deregulation rules that may be enacted in each of the state legislatures and on the federal level. The company is active in those arenas to promote rules that provide customers with choice and quality service.

Utah Requirement: The Commission finds that the RAMPP-5 report should be improved by explicitly linking the Action Plan with the company's actual business plan.

Response: The company uses the DSM targets as determined in the RAMPP process to establish its DSM budget amounts in the its business planning. Generally, the company's business planning involves taking a more global view to grow the business. The company recognizes that market share is important, and one of the most important ways to maintain and grow market share is to retain current customers. The company's strategy to do that is by providing them with low-cost, reliable energy. Much of the company's business and financial planning involves meeting expectations of the financial community, such as earnings, financial coverage ratios, and the like. Because of its focus on customer satisfaction, following a least cost resource acquisition strategy will tend to be consistent with any company business strategy.

Utah Requirement: The company will perform a full load forecast for the RAMPP-5 study.

Response: The company has completed a new load forecast, which is included in the inputs for the RAMPP-5 base case.

Evolution of IRP

The electric utility industry is in a transition from regulated monopolies to open access and competitive markets. This change is occurring primarily through the actions of customers and government agencies. 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 through avenues, such as the federal Electric Consumer Protection Act of 1992 (EPACT), state laws that begin open access, and state laws that establish restructuring principles.

The exact form of the industry is uncertain at this time. 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, distribution companies, or combinations of those three structures.

PacifiCorp believes that the integrated resource planning process needs to change as the industry is changing. As the electric utility industry evolves to a more competitive marketplace, the need for planning under commission oversight decreases, and the assumptions of traditional IRP rules increasingly do not fit the new environment. At this time, however, the company is not recommending that the IRP codes, standards, and rules be changed in each state. Changing IRP rules now would not be a wise investment of time for all the parties involved. It is not possible to discern what form (or forms) the electric utility industry of the future will take. Changing IRP rules should wait until restructuring proceeds further, and all of the parties can clearly understand the changes and ways IRP could meet the new goals of the utility industry and regulation.

PacifiCorp believes the best approach for now is to make some changes in assumptions used for IRP. In addition, regulatory authorities will need to allow some flexibility in the way companies meet existing IRP rules. This is especially true as changes in the industry create conditions that do not match the assumptions underlying some of the IRP rules.

Several assumptions of traditional IRP's increasingly do not fit the new environment: 1) assumption of long-range predictability; 2) assumption that utilities will rely primarily on building new power plants for new sources of power; 3) assumption that the utility has social obligations commensurate with a secure service territory and monopoly status; and 4) assumption that an open environment of information sharing will not hurt the competitive position of the utility.

1) Assumption of long-range predictability

The assumption of long-range predictability no longer meets the needs of the new environment. Current IRP rules assume that existing customers will remain on the regulated utility's system indefinitely. However, in a competitive marketplace, customers may not stay on the utility's system. A shorter time horizon (ten years or less) would help with recognition of the uncertain nature of the utility's business.

The costs of new generation sources are less predictable today than they were several years ago. Competition in the power generation market has resulted in falling prices.

Another aspect of assumed long-range predictability is the requirement for short-term action plans. If the action plan must identify specific times for specific actions, it is not useful to the utility. When utilities built and owned their own power plants with long lead times, they could evaluate those acquisitions years ahead of decision-making, and identify specific times for specific actions. 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. In today's environment, action plans need to focus on general strategies to remain useful to the utility and other parties.

2) Assumption that utilities will rely primarily on building new power plants for new sources of power

The model on which IRP rules developed assumed utilities would rely on building new power plants for future sources of power. Instead, utilities increasingly rely on the market. As long as a surplus exists, market costs tend to be lower than the full cost of building a new power plant, and a market strategy can carry less risk. However, using the market for power to meet customer needs requires quick decision making. Opportunities do not wait for a utility to do a complete IRP analysis of the market purchase compared to all other possibilities. The company must make those decisions using its best judgment and information from analyses already performed.

3) Assumption that the utility has social obligations commensurate with a secure service territory and monopoly status

In the past, when a utility had a secure service territory with monopoly status, it also assumed certain social obligations. When a utility is competing with others who do not have expenses related to social obligations, the utility is disadvantaged in the market. Current IRP rules translate this through an expectation that the utility will plan primarily for lowest Total Resource Cost (TRC). The interpretation of least cost by state utility commissions has led to a TRC definition that includes utility cost, customer costs for DSM, and non-energy benefits of DSM. Using this TRC standard for planning leads to higher levels of DSM and higher customer prices than a focus on utility costs and retail prices. Broadening the definition of "least cost" to incorporate customers' price concerns will increase the usefulness of IRP to both the utility and regulators.

4) Assumption that an open environment of information sharing will not hurt the competitive position of the utility

   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.

For these reasons, PacifiCorp believes IRP rules need a re-examination. However, the company is not calling for a revamping of the rules at this time, for the reasons discussed above. The company is asking for more regulatory flexibility in IRP expectations and in how the commissions apply the rules to each utility.

The company provided a table in the RAMPP-4 Update Report to indicate the ways in which IRP could change in response to the changing industry. The following is a revision of that table:

Old-Style IRP	New-Style IRP
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.

Old-Style IRP	New-Style IRP
Consider environmental effects of electricity production and transmission.	Consider environmental effects of electricity production and transmission to minimize future risks.
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.	Updating as needed.
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.

PacifiCorp introduced an Update Report into the IRP cycle at the end of 1996 (the RAMPP-4 Update - 1997 IRP Report). The purpose of the Update Report was to respond to the rapidly changing nature of the industry. IRP, as traditionally conducted at PacifiCorp, resulted in a report which was generally out-of-date by the time the company filed it every two years. This occurred because of the sequence of activities in each cycle: update inputs, develop base case, preparation and analysis of sensitivities, draft report, comments, and then the final report. Thus, the time period between updating the inputs and issuing the final report was at least 18 months. By that time, costs had changed, markets had changed, and even the company's situation could have changed. Given today's market realities and the need to make quick decisions, an out-of-date report is not very useful to the company.

A re-ordering of the sequence of activities is a way to provide a more up-to-date report. The following is the company's RAMPP-5 sequence of activities. This sequence achieves the goal of minimizing the time between updating inputs and issuing a report.

1) Prepare and analyze sensitivities using the base case from the prior report,

2) Update inputs,

3) Develop new base case and compare it to the prior base case,

4) Develop action plan,

5) Issue draft report,

6) Receive comments on draft report,

7) Revise and issue final report.

A key reason for this revised sequence is the knowledge gained from the RAMPP-3 and RAMPP-4 sensitivities. Those sensitivities showed that the inputs that have the most impact on long-term planning are also those that are the most likely to change during a planning cycle: market prices and gas prices. The new sequence allows the company to use more up-to-date information on these two key inputs in developing its action plan.

The company is providing the same level of information and involving the public advisory group at all stages of the process. The difference is the sequence. In PacifiCorp's RAMPP-5 approach, the sensitivities will examine ways how critical uncertainties affect results. The new base case will identify the latest market information and use it to help develop the action plan.

The future RAMPP process is uncertain now. The company will carefully watch industry and regulatory changes over the next year. Toward the end of 1998, the company will review those changes with regulators and discuss the most appropriate strategy regarding its IRP process.

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. The group identifies issues, suggests changes or additions to input assumptions, and submits comments on the draft report.

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), for RAMPP-4 (in 1994 and 1995), for the RAMPP-4 Update (in 1995 and 1996), and for RAMPP-5 in 1997. 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.

The company held six public advisory group meetings as it developed the sensitivities from the RAMPP-4 Update base case and updating of input assumptions for the RAMPP-5 base case:

January 31, 1997	April 11, 1997
June 13, 1997	August 15, 1997
September 12, 1997	October 24, 1997

The first two meetings focused on sensitivities from the RAMPP-4 Update base case. The next two meetings focused on updating the model inputs and preparation of the new RAMPP-5 base case. The fifth meeting discussed the draft action plan. The last meeting allowed participants to give the company feedback and comments on the full draft report.

Participants in the RAMPP-5 Advisory Group included public agency staff, private groups, and customer representatives. Following is a list of the groups and individuals represented:

Applied Economics Group
Community Energy Project (representing residential customers)
Idaho Public Utilities Commission
Montana Department of Environmental Quality

Montana Consumer Counsel
Northwest Conservation Act Coalition
Oregon Department of Energy
Oregon Public Utility Commission
Portland General Electric
Utah Committee of Consumer Services
Utah Department of Natural Resources
Utah Division of Public Utilities
Utah Public Service Commission
Washington Department of Community Trade
    and Economic Development
Washington Utilities and Transportation Commission
Washington Water Power
Wyoming Public Service Commission

Chapter 3: RAMPP-4 Update Sensitivity Results

The sensitivities performed for this report used the same inputs and assumptions as the RAMPP-4 Update base case, as reported in the RAMPP-4 Update Report issued December 1996. For this RAMPP-5 report the company performed two categories of sensitivities. At the January 31, 1997 meeting, the public advisory group identified the sensitivities they wanted included in this report. This report will refer to them as the cases. The technical appendix includes full supporting detail for the results of those cases. A second category of sensitivities are sweeps, they are explained below.

As the company began the cases, it became clear that a more complete analysis of the uncertainty surrounding some of the issues would be beneficial. The company decided to add sensitivities which increased or decreased the value of a key input in small steps. The company performed several sensitivities for each issue by varying a key input in small steps; these sensitivities created a sweep. By doing the same thing for several issues, the company created several sweeps. However, adding these additional sensitivities as cases, with the accompanying documentation, would quickly become unwieldy. Therefore, the company developed a two-part documentation plan. This included reporting the results of the cases and the sensitivities in the Report, and including in the technical documentation complete output results for the cases only. The technical appendix will not provide full documentation of the sensitivities added in the sweeps. The company discussed this approach with the public advisory group at the April 11 meeting, and received their support.

An example of a sweep would begin with a case that assumes that gas prices increase by 50 percent. The sweep also includes additional sensitivities, each assuming a different level of gas price increase: one would assume the gas price increases by 10 percent, one at 20 percent, one at 30 percent, one at 40 percent, and so on, up to one at 100 percent. In all of these sensitivities, all other inputs remain the same except for the gas price increase level. The additional sensitivities included in the sweeps provide a view of how step-by-step changes in the level of a key input can affect model results and planning. Therefore, each sweep includes both cases and sensitivities.

Table 3 - 1
List of Sensitivities

Description			
Sweep 1			
Gas/Market Price Jump in 1998 by 0 to 200%, 40% Linkage with Market Prices			
Case 1	0%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	5%	Gas Price Jump in 1998	2% Short Term Market Price Increase
	10%	Gas Price Jump in 1998	4% Short Term Market Price Increase
	15%	Gas Price Jump in 1998	6% Short Term Market Price Increase
	20%	Gas Price Jump in 1998	8% Short Term Market Price Increase
Case 35	25%	Gas Price Jump in 1998	10% Short Term Market Price Increase
	30%	Gas Price Jump in 1998	12% Short Term Market Price Increase
	40%	Gas Price Jump in 1998	16% Short Term Market Price Increase
Case 36	50%	Gas Price Jump in 1998	20% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	28% Short Term Market Price Increase
	90%	Gas Price Jump in 1998	36% Short Term Market Price Increase
Case 37	110%	Gas Price Jump in 1998	44% Short Term Market Price Increase
	130%	Gas Price Jump in 1998	52% Short Term Market Price Increase
	150%	Gas Price Jump in 1998	60% Short Term Market Price Increase
	175%	Gas Price Jump in 1998	70% Short Term Market Price Increase
	200%	Gas Price Jump in 1998	80% Short Term Market Price Increase
Sweep 2			
Gas Price Jump in 1998 by 0 to 200%, No Market Price Increase			
Case 1	0%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	5%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	10%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	15%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	20%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	25%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	30%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	40%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	50%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	90%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	110%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	130%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	150%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	175%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	200%	Gas Price Jump in 1998	0% Short Term Market Price Increase
Sweep 3			
Gas/Market Price Jump in 2003 by 0 to 200%, 40% Linkage with Market Prices			
Case 1	0%	Gas Price Jump in 2003	0% Short Term Market Price Increase
	5%	Gas Price Jump in 2003	2% Short Term Market Price Increase
	10%	Gas Price Jump in 2003	4% Short Term Market Price Increase
	15%	Gas Price Jump in 2003	6% Short Term Market Price Increase
	20%	Gas Price Jump in 2003	8% Short Term Market Price Increase
Case 81	25%	Gas Price Jump in 2003	10% Short Term Market Price Increase
	30%	Gas Price Jump in 2003	12% Short Term Market Price Increase
	40%	Gas Price Jump in 2003	16% Short Term Market Price Increase
Case 82	50%	Gas Price Jump in 2003	20% Short Term Market Price Increase
	70%	Gas Price Jump in 2003	28% Short Term Market Price Increase
	90%	Gas Price Jump in 2003	36% Short Term Market Price Increase
Case 83	110%	Fas Price Jump in 2003	44% Short Term Market Price Increase
	130%	Gas Price Jump in 2003	52% Short Term Market Price Increase
	150%	Gas Price Jump in 2003	60% Short Term Market Price Increase
	175%	Gas Price Jump in 2003	70% Short Term Market Price Increase
	200%	Gas Price Jump in 2003	80% Short Term Market Price Increase
Sweep 4			
70% Gas Price Jump in 1998, 0 to 100% Linkage with Market Prices			
	70%	Gas Price Jump in 1998	0% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	10% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	20% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	30% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	40% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	50% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	60% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	70% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	80% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	90% Short Term Market Price Increase
	70%	Gas Price Jump in 1998	100% Short Term Market Price Increase

Table 3 - 1
List of Sensitivities

Description

Sweep 5
Gas Escalation From Low to Triple the Beginning Price by 2006

Case 31	Low Escalation 0.3% till 2006 -0.3% thereafter
Case 1	Med Escalation 2.4% till 2006 1.0% thereafter
Case 32	High Escalation 4.5% till 2006 2.4% thereafter
Case 33	Double by 2006 8.0% till 2006 2.4% thereafter
Case 34	Triple by 2006 13 % till 2006 2.4% thereafter

Sweep 6
Load Change From +625 MW To -625 MW Over Five Years

	625	MW OWC Industrial Load	Loss	Over Five Years
	500	MW OWC Industrial Load	Loss	Over Five Years
	375	MW OWC Industrial Load	Loss	Over Five Years
	250	MW OWC Industrial Load	Loss	Over Five Years
	125	MW OWC Industrial Load	Loss	Over Five Years
Case 1	0	No Change		
	125	MW OWC Industrial Load	Gain	Over Five Years
	250	MW OWC Industrial Load	Gain	Over Five Years
	375	MW OWC Industrial Load	Gain	Over Five Years
	500	MW OWC Industrial Load	Gain	Over Five Years
	625	MW OWC Industrial Load	Gain	Over Five Years

Sweep 7
Geographical Load Variation Cases

Case 41	125	MW OWC Industrial Customer Load Loss in 1999
Case 42	125	MW Utah Industrial Customer Load Loss in 1999
Case 43	125	MW Wyoming Industrial Customer Load Loss in 1999
Case 44	125	MW Idaho Industrial Customer Load Loss in 1999
Case 45		Utah with 4 Percent Load Growth
Case 46	625	MW OWC Industrial Customer Load Loss in 1999
Case 47	625	MW Utah Industrial Customer Load Loss in 1999
Case 48	625	MW OWC Industrial Customer, 125 MW/Year Starting in 1999
Case 49	625	MW Utah Industrial Customer, 125 MW/Year Starting in 1999

Sweep 8
Environmental Adders From 0 To $40/Ton CO2, NOx & TSP Adders

Case 1	$	0	/Ton CO2	$ 0	/Ton NOx and $ 0	/Ton TSP
	$	1	/Ton CO2	$ 100	/Ton NOx and $ 125	/Ton TSP
	$	2	/Ton CO2	$ 200	/Ton NOx and $ 250	/Ton TSP
	$	3	/Ton CO2	$ 300	/Ton NOx and $ 375	/Ton TSP
	$	4	/Ton CO2	$ 400	/Ton NOx and $ 500	/Ton TSP
	$	5	/Ton CO2	$ 500	/Ton NOx and $ 625	/Ton TSP
	$	6	/Ton CO2	$ 600	/Ton NOx and $ 750	/Ton TSP
	$	7	/Ton CO2	$ 700	/Ton NOx and $ 875	/Ton TSP
	$	8	/Ton CO2	$ 800	/Ton NOx and $ 1,000	/Ton TSP
	$	9	/Ton CO2	$ 900	/Ton NOx and $ 1,125	/Ton TSP
Case 21	$	10	/Ton CO2	$ 1,000	/Ton NOx and $ 1,250	/Ton TSP
Case 22	$	25	/Ton CO2	$ 2,500	/Ton NOx and $ 3,125	/Ton TSP
Case 23	$	40	/Ton CO2	$ 4,000	/Ton NOx and $ 5,000	/Ton TSP

Other Cases

	RAMPP-4 Base Case
Case 12	No DSM
Case 24	Solar Technological Price Curve Necessary to Bring in Solar
Case 38	Lower Gas Resource Availability
Case 51	Flat Wholesale Short Term Market Prices
Case 61	10 Percent more Transmission Capacity East to West
Case 62	10 Percent Reduction in All Transmission Line Capacity
Case 71	25 Percent Reduction in Hydro Utilization

The two pages of Table 3-1 show the full listing of sweeps. Most of the cases fall into one or more of the sweeps. Sweeps 1 through 5 focus on gas and market prices. Gas prices refer to natural gas, while market prices refer to the wholesale short-term market for electricity. Sweep 6 covers load changes. Sweep 7 includes cases on geographical load variation. Sweep 8 covers environmental adders. The last group of cases cover a variety of issues that do not fall neatly into one of the above categories.

The gas and wholesale market price sweeps explore the impact of changing price levels and a changing relationship between gas and wholesale market prices. That relationship involves the degree to which a gas price change triggers a change in wholesale market prices. A 100 percent relationship would mean that a 10 percent gas price increase would result in a 10 percent wholesale market price increase. A 40 percent relationship would mean that a 10 percent gas price increase would result in a 4 percent wholesale market price increase. To test the impact of changing price levels and relationships, the company included sweeps which vary three elements of the gas and wholesale market price issue: timing, price increase level, and linkage between gas and wholesale market prices. The company included sweeps that assume a price jump in either 1998 or 2003. They assume a gas price jump between 0 and 200 percent, and they assume a linkage between 0 and 100 percent. These variations in the timing of the price jump, amount of the price jump, and degree of linkage between gas and wholesale market prices provide for a rich analysis of the relationships among them and their impact on modeling results and planning.

Since the RAMPP-4 Update base case is the base case for all of the cases and sensitivities included in this chapter, Tables 3-2 and 3-3 show key input assumptions for that base case. These are the natural gas and wholesale market prices used in the RAMPP-4 Update base case. Table 3-2 shows natural gas prices and escalation levels; Table 3-3 shows wholesale market prices and escalation levels. Under the base case assumptions, gas prices increase at an annual rate of 2.5 percent real until 2006; from that point on they increase at an annual rate of 1 percent real. The beginning price varies by region, as shown on Table 3-2. In the cases and sensitivities which assume a price jump in either 1998 or 2003, gas price escalation before and after the jump remains at 2.5 percent real until 2006 and 1 percent real after 2006. Wholesale market prices increase at different rates by year and by high-load hours or low-load hours, as shown on Table 3-3. As with gas prices, before and after the price jump wholesale market prices return to the same annual escalation rate as they would have without the jump.

Table 3 - 2
Natural Gas Price Projections (RAMPP-4 Update)
Westside and Eastside (1997 $/MMBtu)

	Raw Gas Price $1997 $/MMBtu		Escalation Rate	
	WESTSIDE	EASTSIDE	WESTSIDE	EASTSIDE
1997	$1.28	$1.38		
1998	$1.31	$1.42	2.4%	3.2%
1999	$1.35	$1.47	2.4%	3.2%
2000	$1.38	$1.52	2.5%	3.3%
2001	$1.41	$1.57	2.5%	3.3%
2002	$1.45	$1.62	2.5%	3.4%
2003	$1.49	$1.68	2.6%	3.5%
2004	$1.53	$1.74	2.6%	3.5%
2005	$1.57	$1.80	2.7%	3.5%
2006	$1.61	$1.86	2.7%	3.6%
2007	$1.62	$1.88	1.0%	1.1%
2008	$1.64	$1.90	1.0%	1.1%
2009	$1.66	$1.92	1.0%	1.1%
2010	$1.67	$1.94	1.0%	1.1%
2011	$1.69	$1.96	1.0%	1.1%
2012	$1.71	$1.98	1.0%	1.1%
2013	$1.72	$2.01	1.0%	1.1%
2014	$1.74	$2.03	1.0%	1.1%
2015	$1.76	$2.05	1.0%	1.1%
2016	$1.78	$2.07	1.0%	1.1%

Graph 3 - 2
Natural Gas Price Projections ($1997 $/MMBtu)

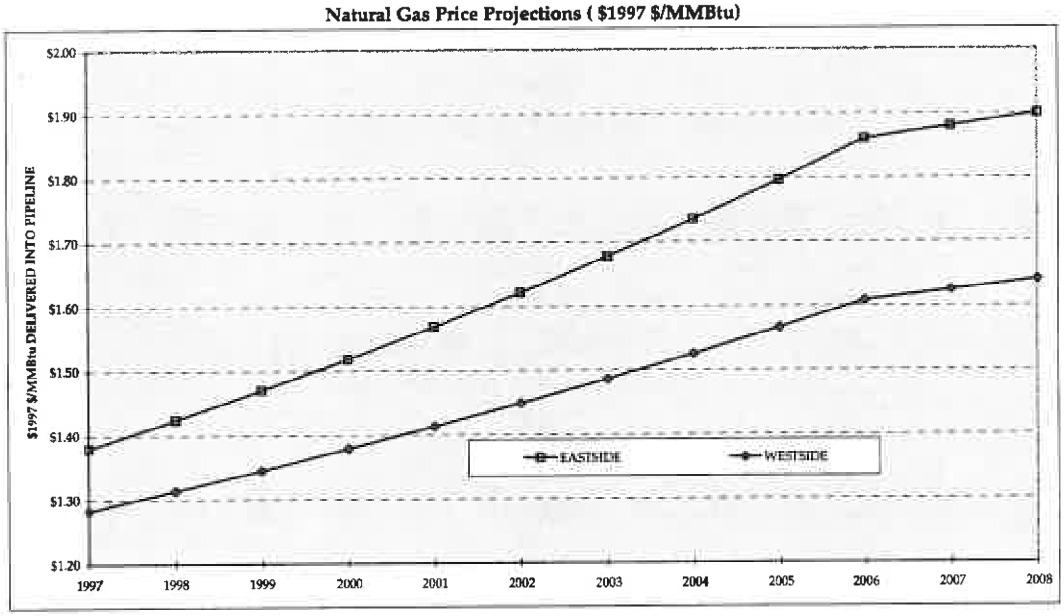
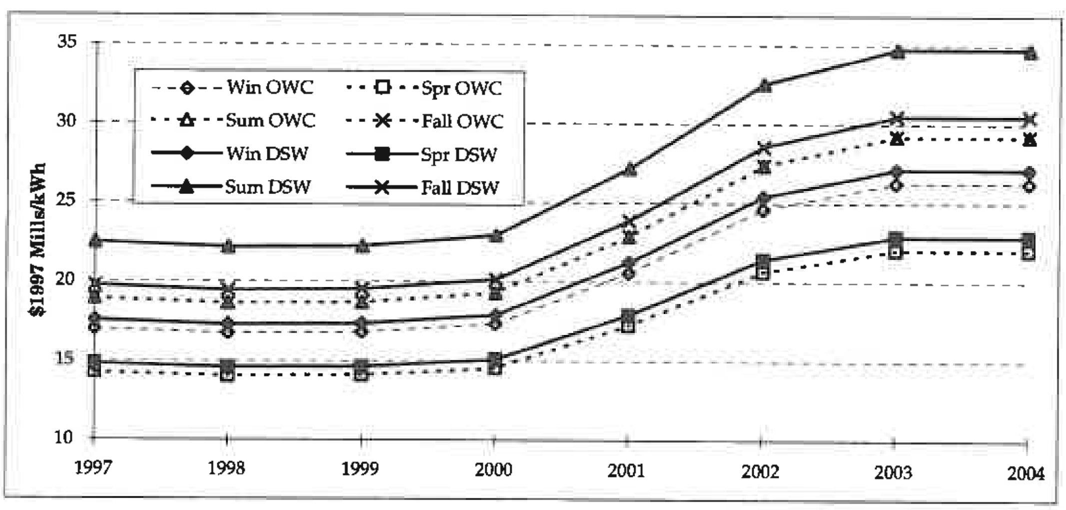


Table 3 - 3
Wholesale Market Prices and Escalation (RAMPP-4 Update)
$1997 Mills/kWh

	OWC				DSW				Average	Real
	Win	Spr	Sum	Fall	Win	Spr	Sum	Fall	Annual	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%

Graph 3 - 3
Wholesale Market Prices: High-Load Hours



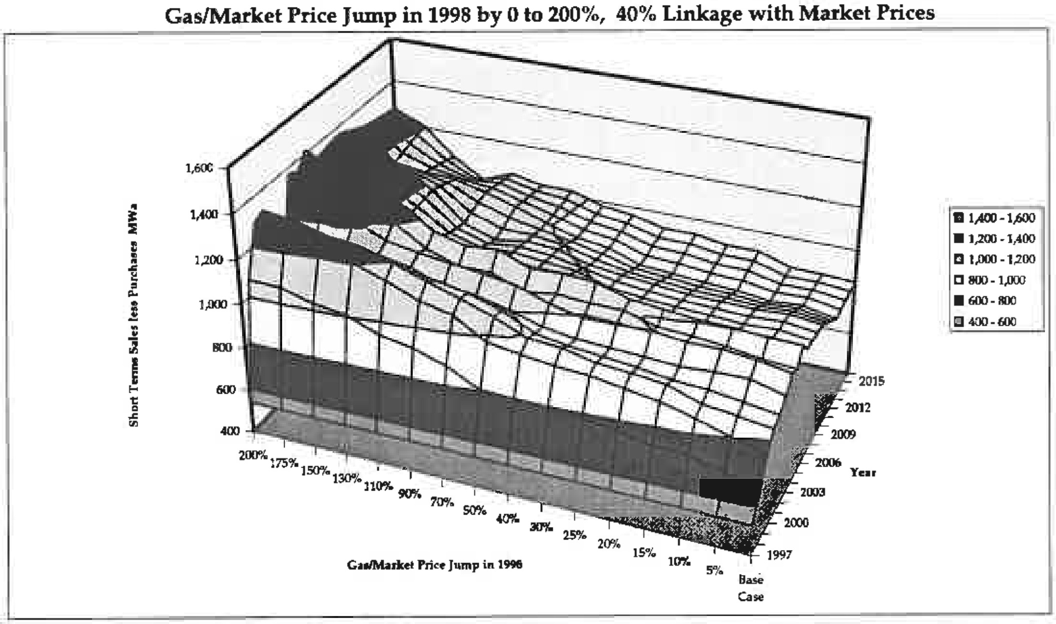
OWC = COB (California Oregon Border) and Mid Columbia based prices.
DSW = Palo Verde based prices.

Sweep 1: Gas/Market Price Jump 1998, 40 Percent Linkage

The first sweep varies the amount of the gas and wholesale market price jump in 1998 by 0 to 200 percent, while holding the linkage between gas prices and wholesale market prices at 40 percent. The company performed numerous tests to identify the level of linkage at which short-term wholesale sales and purchases remained at equilibrium through the range of gas price increases. At a linkage less than 40 percent, gas prices increased at a much faster rate than wholesale market prices. As a result, new resources became increasingly expensive while the wholesale market price remained low. Under these conditions, the model made excessive short-term purchases but almost no short-term sales since the wholesale market price remained too low. At a higher linkage than 40 percent, new resources became increasingly expensive while the wholesale market price also became increasingly high. In these circumstances, the model made excessive short-term sales but no offsetting short-term purchases because of the high wholesale market prices.

Graph 3-4 shows the relatively consistent pattern of net short-term transactions (short-term sales less purchases) across the levels of gas/market price jumps in 1998 when the linkage is kept at 40 percent. There is a slight increase in net short-term transactions as the gas/market price jump increases. However, at a higher linkage, this increase is much more dramatic.

Graph 3 - 4
Sweep 1: Net Short-Term Transactions
Gas/Market Price Jump in 1998 by 0 to 200%, 40% Linkage with Market Prices



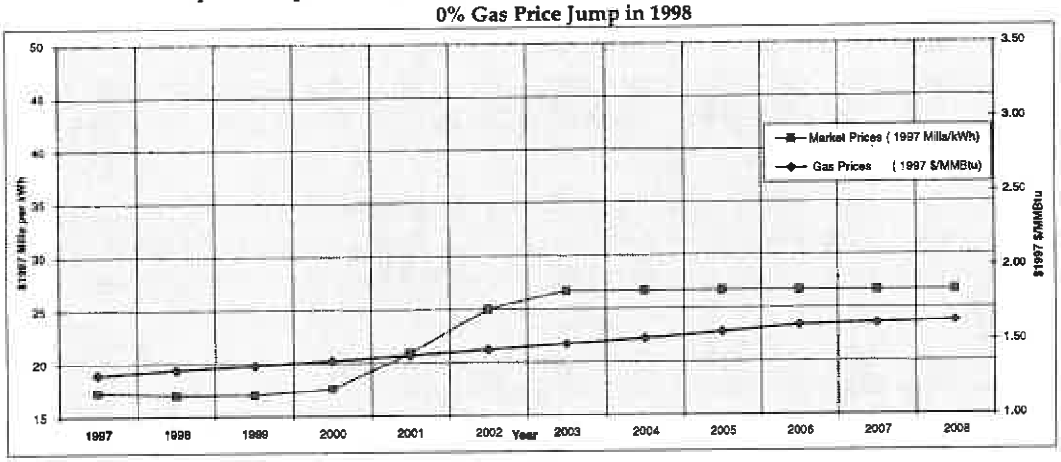
Sweep 1 assumes a consistent 40 percent linkage between gas and wholesale market prices. Under this assumption, if gas prices increase by 20 percent, wholesale market prices increase by 8 percent; if gas prices increase by 100 percent, wholesale market prices increase by 40 percent. After the price jump in 1998, natural gas prices increase at an annual rate of 2.5 percent real until 2006. After 1998 wholesale market prices increase at the rates shown in Table 3-3.

Graph 3-5 shows the pattern for gas and wholesale market prices for three of the cases in Sweep 1: the base case (0 percent gas price jump), a gas price jump of 50 percent and a gas price jump of 110 percent. It shows that in the base case, gas prices remain on a more stable course than do wholesale market prices. In the 50 percent gas price jump case, gas prices take an initial jump but then remain on a relatively stable course. Wholesale market prices show a more erratic pattern. In the 110 percent gas price jump case, gas prices take a significant jump right away, and wholesale market prices show a very erratic pattern.

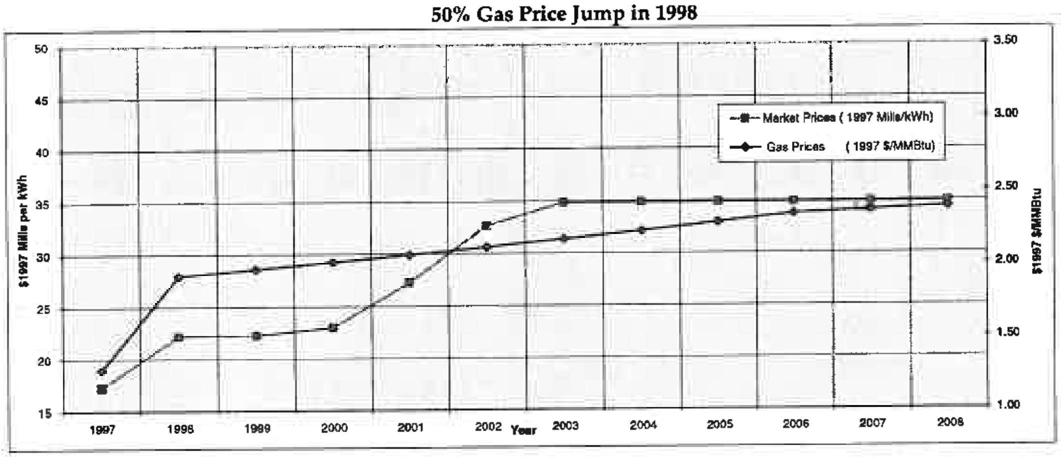
Table 3-6 shows the results from the cases and sensitivities included in Sweep 1 at the tenth year (2006) of the 20 year planning horizon. The first section of the table shows capacity additions, the second section shows the amount of energy provided by those capacity additions, the third section shows the average annual emissions for the entire 50 year study period, and the fourth section shows financial results for the 20 years of the planning horizon. Table 3-7 shows the difference in results for each case after subtracting off the results for the base case.

Assuming a gas/market price jump in 1998 increases the amount of DSM compared to the base case. This is because the higher gas price results in DSM being more cost effective. DSM increased from a cumulative 187 MWa by the tenth year in the base case to 218 MWa in the sensitivity with a 200 percent price jump. Thus a 200 percent gas price increase resulted in a 17 percent increase in DSM.

Graph 3 - 5
Sweep 1: Examples of Gas/Market Prices, 40% Linkage between Gas and Market Prices
0% Gas Price Jump in 1998



50% Gas Price Jump in 1998



110% Gas Price Jump in 1998

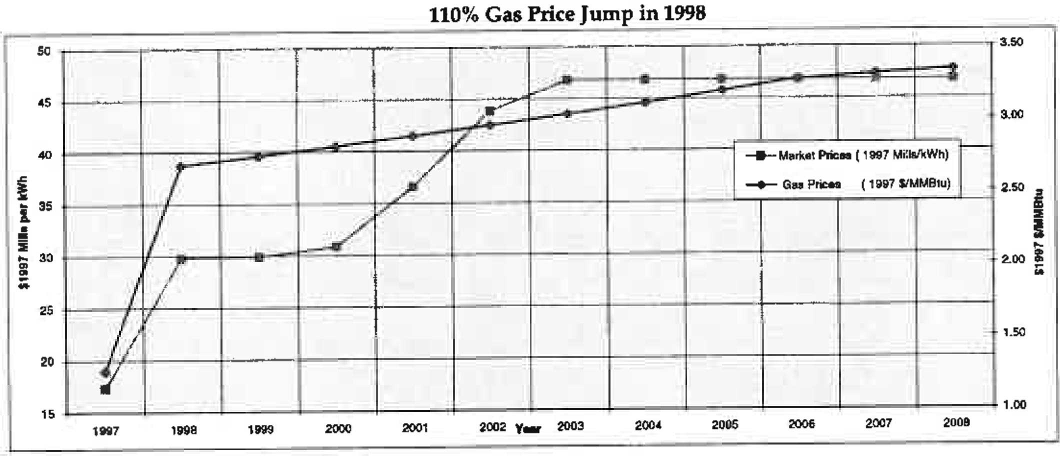


Table 3 - 6

Sweep 1: Resource Selections by 2006, Emissions, and Financial Results

Gas/Market Price Jump in 1998 by 0 to 200%, 40% Linkage with Market Prices

	Base Case	5%	10%	15%	20%	25%	30%	40%	50%	70%	90%	110%	130%	150%	175%	200%
Case #	1	1-1	1-2	1-3	1-4	1-5	1-6	1-7	1-8	1-9	1-10	1-11	1-12	1-13	1-14	1-15
Summer Peak Capacity in Year 2006 (MW)																
1 Native Load	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944
2 Long Term Sales	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362
3 less DSM	(254)	(254)	(257)	(260)	(264)	(266)	(268)	(271)	(276)	(282)	(285)	(286)	(288)	(288)	(290)	(290)
4 **Total Requirements**	10,052	10,052	10,049	10,046	10,042	10,040	10,038	10,035	10,030	10,024	10,021	10,020	10,018	10,018	10,016	10,016
5 Existing Generation	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,618	9,465	9,380	9,427	9,467	9,398	9,352
6 Long Term Purchase	658	658	658	658	658	658	658	658	658	658	658	658	658	658	658	658
7 New Resources																
8 Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9 Cogeneration	625	629	594	562	559	544	533	519	499	421	374	202	202	202	63	-
10 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Transmission	-	-	-	-	-	-	-	-	-	-	-	190	262	337	518	613
13 Peaking Resources	121	118	149	178	177	189	198	209	224	35	186	270	224	185	253	298
14 **Total Resources**	11,058	11,058	11,055	11,052	11,047	11,044	11,042	11,038	11,033	296	341	321	247	172	129	97
										11,027	11,023	11,022	11,020	11,021	11,019	11,018
15 Reserves	1,005	1,005	1,005	1,005	1,004	1,004	1,004	1,003	1,003	1,002	1,002	1,002	1,002	1,002	1,002	1,001
16 Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Annual Energy in Year 2006 (MWa)																
17 Native Load	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598
18 Pump Storage/Peak Return	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
19 Long Term Sales	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086
20 Short Term Sales	1,291	1,301	1,289	1,286	1,281	1,300	1,294	1,339	1,326	1,323	1,327	1,351	1,413	1,454	1,487	1,533
21 less DSM	(187)	(187)	(189)	(192)	(195)	(198)	(199)	(202)	(206)	(211)	(214)	(215)	(217)	(217)	(218)	(218)
22 **Total Requirements**	9,045	9,055	9,041	9,035	9,026	9,043	9,036	9,078	9,061	9,052	9,054	9,076	9,136	9,178	9,210	9,255
23 Existing Generation	7,689	7,704	7,725	7,757	7,766	7,785	7,801	7,850	7,877	7,933	7,834	7,763	7,813	7,849	7,792	7,768
24 Long Term Purchases	466	466	466	466	466	466	466	466	466	466	466	466	466	466	466	466
25 Short Term Purchases	358	350	344	333	319	328	307	295	283	262	266	257	243	216	196	192
26 New Resources																
27 Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Cogeneration	532	535	506	479	475	463	462	467	435	359	319	173	173	173	54	-
29 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31 Transmission	-	-	-	-	-	-	-	-	-	-	-	172	238	306	473	559
32 Peaking Resources	-	-	-	-	-	-	-	-	-	32	169	245	203	168	229	271
33 **Total Resources**	9,045	9,055	9,041	9,035	9,026	9,043	9,036	9,078	9,061	9,052	9,054	9,076	9,136	9,178	9,210	9,255
Average Annual Emission in 1997-2046 (1000 tons)																
34 CO_2	59,536	59,682	59,777	59,914	59,980	60,059	60,115	60,220	60,419	61,136	61,840	62,734	63,318	63,537	64,063	64,710
35 NO_x	131.9	132.4	132.7	133.2	133.5	133.8	134.0	134.6	135.3	136.5	137.5	138.5	139.2	139.4	139.8	140.4
Financial Results with End Effects to 2046																
36 50-year Utility Cost																
37 NPV at 7.9% (million $)	45,827	45,752	45,739	45,721	45,698	45,696	45,660	45,633	45,571	45,037	44,510	44,044	43,413	42,862	42,103	41,367
38 Real Levelized (mills/kWh)	41.83	41.73	41.74	41.72	41.71	41.71	41.74	41.71	41.67	41.22	40.76	40.33	39.76	39.26	38.56	37.89
39 50-year Total Resources Cost																
40 NPV at 7.9% (million $)	45,304	45,205	45,192	45,174	45,166	45,163	45,123	45,095	45,036	44,495	43,975	43,509	42,880	42,328	41,569	40,834
41 Real Levelized (mills/kWh)	39.95	39.86	39.85	39.83	39.83	39.83	39.79	39.77	39.71	39.24	38.78	38.37	37.81	37.33	36.66	36.01

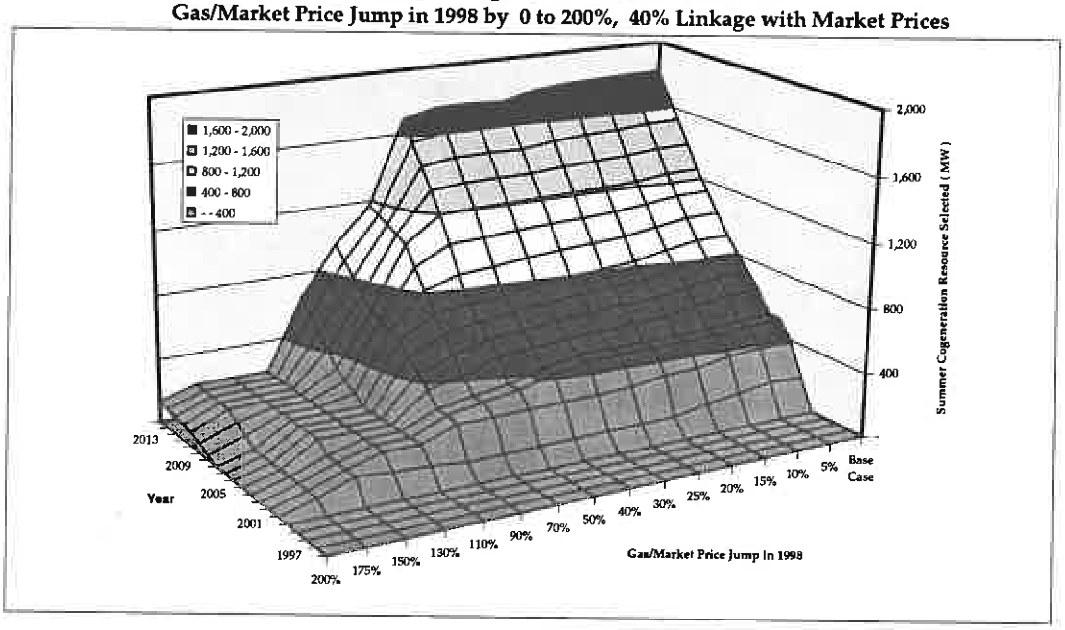
Table 3 - 7

Sweep 1: Sensitivity less Base Case - Resource Selections by 2006, Emissions, and Financial Results
Gas/Market Price Jump in 1998 by 0 to 200%, 40% Linkage with Market Prices

	Base Case	5%	10%	15%	20%	25%	30%	40%	50%	70%	90%	110%	130%	150%	175%	200%
Case #	1	1-1	1-2	1-3	1-4	1-5	1-6	1-7	1-8	1-9	1-10	1-11	1-12	1-13	1-14	1-15
Summer Peak Capacity in Year 2006 (MW)																
1 Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2 Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 less DSM	-	-	(3)	(6)	(10)	(12)	(14)	(17)	(22)	(28)	(31)	(32)	(34)	(34)	(36)	(36)
4 Total Requirements	-	-	(3)	(6)	(10)	(12)	(14)	(17)	(22)	(28)	(31)	(32)	(34)	(34)	(36)	(36)
5 Existing Generation	-	-	-	-	-	-	-	-	-	(35)	(188)	(273)	(226)	(186)	(255)	(301)
6 Long Term Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7 New Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9 Cogeneration	-	3	(31)	(63)	(67)	(81)	(92)	(107)	(127)	(205)	(252)	(423)	(423)	(423)	(563)	(625)
10 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Coal	-	-	-	-	-	-	-	-	-	-	-	190	262	337	518	613
12 Transmission	-	-	-	-	-	-	-	-	-	35	186	270	224	185	253	298
13 Peaking Resources	-	(3)	28	56	56	68	77	87	102	175	219	200	126	51	7	(25)
14 Total Resources	-	(0)	(3)	(7)	(11)	(15)	(16)	(21)	(26)	(31)	(36)	(36)	(38)	(37)	(40)	(41)
15 Reserves	-	-	-	-	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)
16 Reserve Margin (RM) (%)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Energy in Year 2006 (MWa)																
17 Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18 Pump Storage/Peak Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19 Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20 Short Term Sales	-	10	(2)	(5)	(10)	8	3	48	35	32	36	60	121	163	196	242
21 less DSM	-	(1)	(3)	(6)	(9)	(11)	(12)	(15)	(19)	(25)	(27)	(29)	(30)	(30)	(32)	(32)
22 Total Requirements	-	9	(5)	(11)	(19)	(3)	(10)	33	16	7	9	31	91	133	164	210
23 Existing Generation	-	15	36	68	76	96	112	161	188	244	144	74	124	160	103	78
24 Long Term Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Short Term Purchases	-	(8)	(14)	(25)	(39)	(30)	(51)	(63)	(75)	(96)	(92)	(101)	(115)	(142)	(162)	(166)
26 New Resources																
27 Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Cogeneration	-	3	(26)	(54)	(57)	(69)	(71)	(66)	(98)	(173)	(213)	(359)	(359)	(359)	(478)	(532)
29 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Coal	-	-	-	-	-	-	-	-	-	-	-	172	238	306	473	559
31 Transmission	-	-	-	-	-	-	-	-	-	32	169	245	203	168	229	271
32 Peaking Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33 Total Resources	-	9	(5)	(11)	(19)	(3)	(10)	33	16	7	9	31	91	133	164	210
Average Annual Emission in 1997-2046 (1000 tons)																
34 CO_2	-	146	242	378	444	523	579	685	883	1,600	2,304	3,198	3,782	4,002	4,527	5,174
35 NO_x	-	0.5	0.8	1.3	1.5	1.9	2.1	2.7	3.4	4.6	5.6	6.6	7.2	7.5	7.9	8.5
Financial Results with End Effects to 2046																
36 50-year Utility Cost																
37 NPV at 7.9% (million $)	-	(75)	(89)	(107)	(129)	(132)	(167)	(195)	(257)	(790)	(1,318)	(1,783)	(2,414)	(2,966)	(3,725)	(4,460)
38 Real Levelized (mills/kWh)	-	(0.10)	(0.09)	(0.11)	(0.12)	(0.12)	(0.09)	(0.12)	(0.16)	(0.61)	(1.07)	(1.50)	(2.07)	(2.57)	(3.27)	(3.94)
39 50-year Total Resources Cost																
40 NPV at 7.9% (million $)	-	(99)	(112)	(130)	(138)	(141)	(181)	(208)	(268)	(809)	(1,329)	(1,794)	(2,424)	(2,976)	(3,735)	(4,470)
41 Real Levelized (mills/kWh)	-	(0.09)	(0.10)	(0.11)	(0.12)	(0.12)	(0.16)	(0.18)	(0.24)	(0.71)	(1.17)	(1.54)	(2.14)	(2.62)	(3.29)	(3.94)

The higher the gas/market price jump in 1998, the less gas-fired cogeneration the model added. In the base case the model added 625 MW of cogeneration by the tenth year. Beginning with a 50 percent price jump, the model began adding smaller amounts, until the 200 percent price when the model added almost no cogeneration. Graph 3-8 shows this pattern.

Graph 3 - 8
Sweep 1: Cogeneration Resources Selected
Gas/Market Price Jump in 1998 by 0 to 200%, 40% Linkage with Market Prices

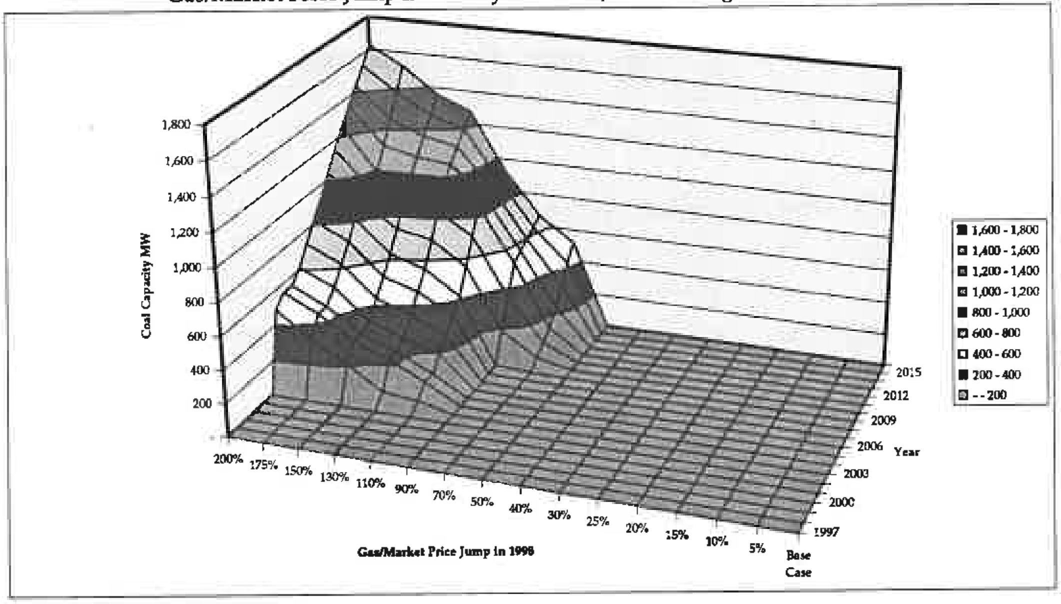


The model ran coal-fired resources more heavily as gas prices increased. At gas price increases of 70 percent or more, the model began building new coal-fired plants in 2009. At gas price jumps of 110 percent or more it began building new coal-fired plants in 2003. Graph 3-9 shows this pattern.

The model also used the transmission option beginning with gas price increases of 70 percent or more. This is a capability of the model to "move" power plants for a cost comparable to wheeling over existing transmission lines plus line losses. However, the cost effectiveness of this option depended on the availability of a wholesale market to sell unused energy. As gas/market prices increased the model built more peaking resources, but abandoned them in favor of coal-fired plants at the highest price jumps.

Table 3-6 shows that average emissions do not significantly vary until gas prices jump by 110 percent or more, when the model built more coal-fired plants.

Graph 3 - 9
Sweep 1: Coal Resources Selected
Gas/Market Price Jump in 1998 by 0 to 200%, 40% Linkage with Market Prices



The financial results for Sweep 1 at the bottom of Table 3-6 show that a 1998 gas/market price jump would not seriously impact customer prices. The reason for this is the 40 percent linkage of gas prices with wholesale market prices. Because of that linkage, wholesale market prices increased along with gas prices, and the model sold excess energy at favorable prices. This short-term wholesale market revenue more than compensated for the increase in operating cost of existing and new gas-fired resources from the higher gas prices.

Sweep 2: Gas Price Jump 1998, No Market Price Increase

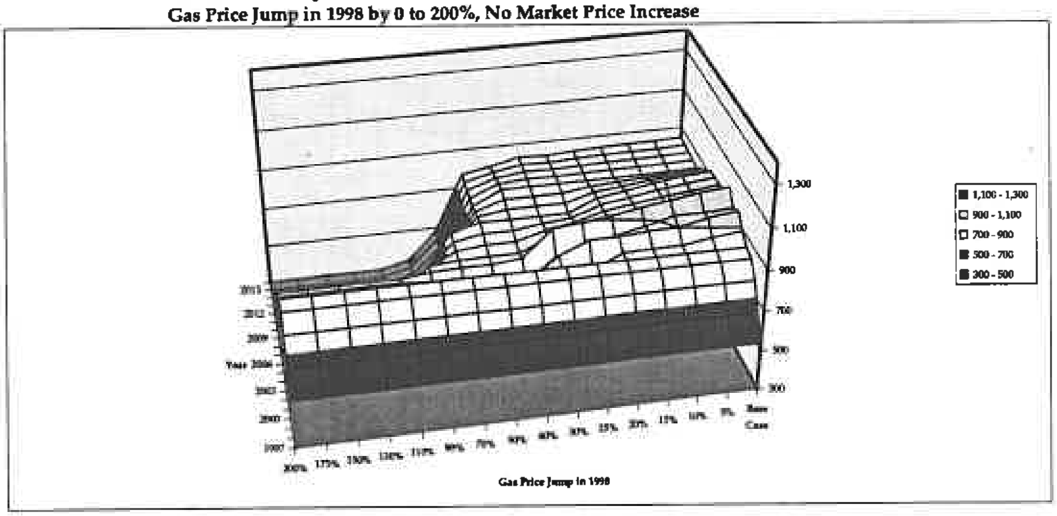
The second sweep allowed the gas price to increase in 1998 by 0 to 200 percent, with no accompanying increase in wholesale market prices (there is no linkage between gas and wholesale market prices in Sweep 2.) The lack of any linkage between gas price increases and wholesale market price increases caused an imbalance in net short-term transactions. As gas prices increased, short-term sales fell off, and short-term purchases increased, because the wholesale market price remained low while new resource costs increased.

Graph 3-10 shows the impact on net short-term transactions. The first graph shows the net result in short-term transactions (sales less purchases), the second shows short-term sales decreasing dramatically once the gas price jump reached about 50 percent, and the third shows short-term purchases increasing dramatically once the gas price jump reached about 70 percent. The resulting imbalance would not be a likely occurrence in the wholesale market. Therefore, the company believes that Sweep 2 is an inaccurate reflection of wholesale market realities. Nevertheless, it is informative about the impact of removing all linkage between these two important indicators of the energy market.

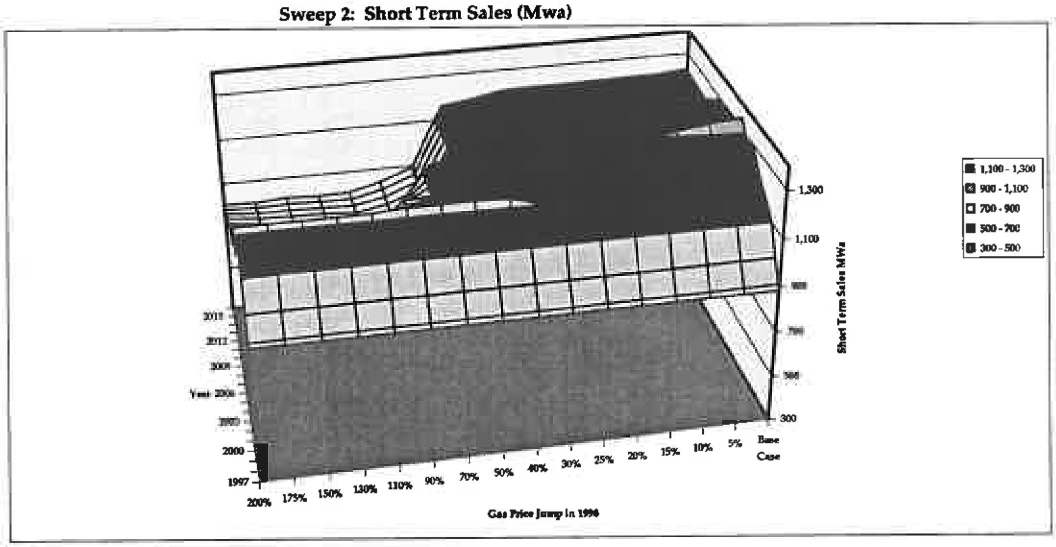
Table 3-11 shows the results from the sensitivities included in Sweep 2 at the tenth year (2006) of the 20 year planning horizon. Table 3-12 shows the difference in results for each case after subtracting off the results for the base case.

A gas price jump in 1998 increased the amount of DSM, as it did in Sweep 1. Also as in Sweep 1, the higher the gas price jump in 1998, the less gas-fired cogeneration the model added. However, without a wholesale market price linkage, the model decreased the cogeneration additions more quickly. This is because plant additions became less cost effective if there was not a good wholesale market in which to sell any excess energy. Graph 3-13 shows this pattern. Once the gas price jump reached about 50 percent, the model dramatically decreased the amount of new cogeneration resources selected. This compares to Sweep 1, where the gas price jump had to be about 70 percent before the model began dramatically decreasing the amount of new cogeneration selected.

Graph 3 - 10
Sweep 2: Net Short Term Transactions
Gas Price Jump in 1998 by 0 to 200%, No Market Price Increase



Sweep 2: Short Term Sales (Mwa)



Sweep 2: Short Term Purchases (MWa)

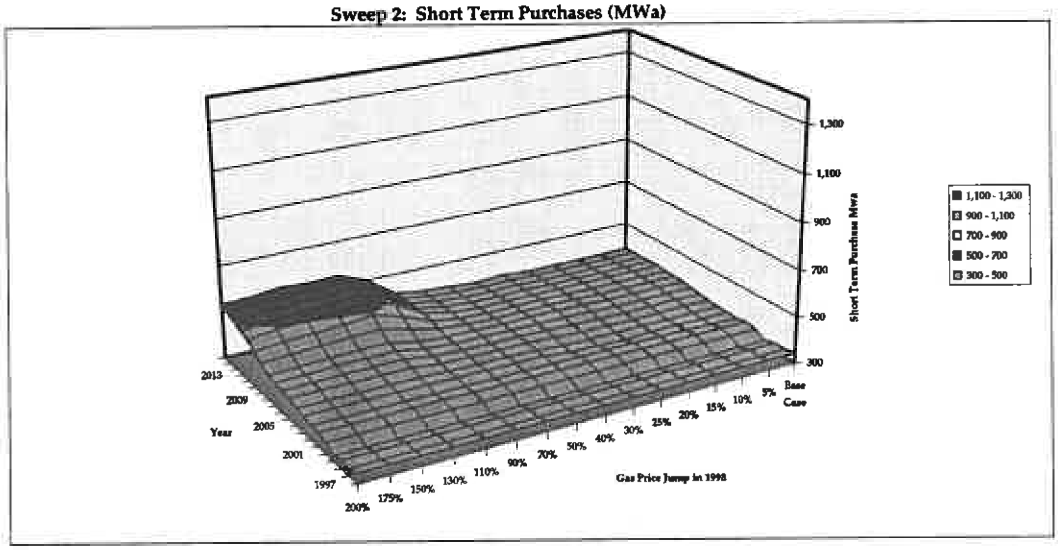


Table 3 - 11

Sweep 2: Resource Selections by 2006, Emissions, and Financial Results
Gas Price Jump in 1998 by 0 to 200%, No Market Price Increase

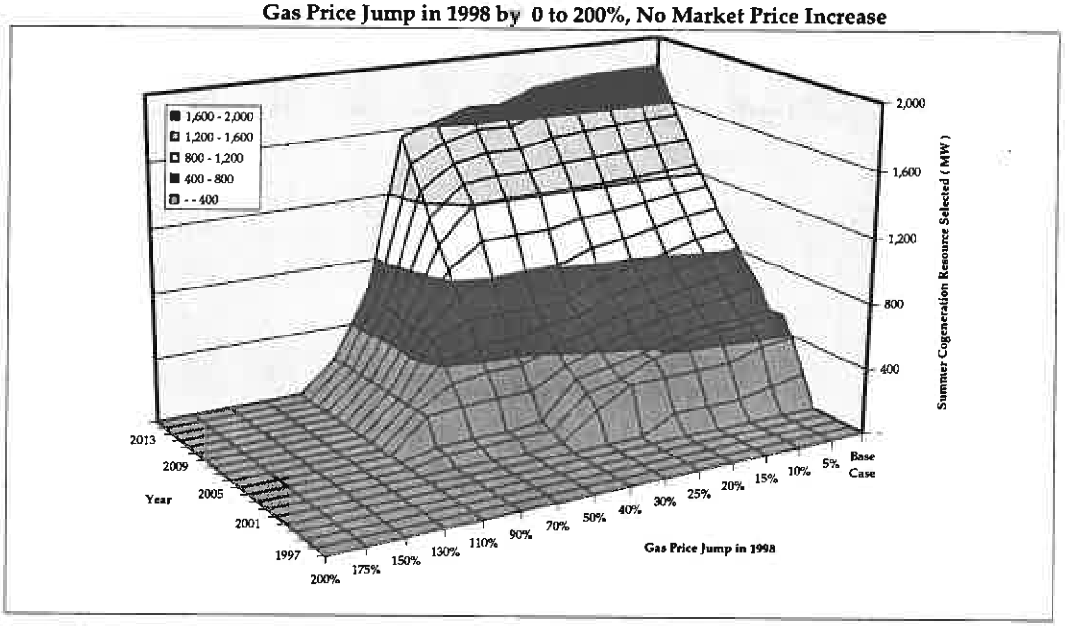
		Base Case	5%	10%	15%	20%	25%	30%	40%	50%	70%	90%	110%	130%	150%	175%	200%
	Case #	1	2-1	2-2	2-3	2-4	2-5	2-6	2-7	2-8	2-9	2-10	2-11	2-12	2-13	2-14	2-15
	Summer Peak Capacity in Year 2006 (MW)																
1	Native Load	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944
2	Long Term Sales	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362
3	less DSM	(254)	(254)	(257)	(260)	(263)	(266)	(267)	(271)	(274)	(280)	(282)	(284)	(285)	(285)	(285)	(285)
4	**Total Requirements**	10,052	10,052	10,049	10,046	10,043	10,040	10,039	10,035	10,032	10,026	10,024	10,022	10,021	10,021	10,021	10,021
5	Existing Generation	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653
6	Long Term Purchase	658	658	658	658	658	658	658	658	658	658	658	658	658	658	658	658
7	New Resources																
8	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Cogeneration	625	593	562	531	487	419	342	227	225	218	197	-	-	-	-	-
10	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Peaking Resources	121	153	182	208	250	314	390	500	500	500	519	713	713	713	712	712
14	**Total Resources**	11,058	11,058	11,054	11,050	11,048	11,044	11,043	11,038	11,036	11,029	11,027	11,024	11,024	11,024	11,023	11,023
15	Reserves	1,005	1,005	1,005	1,005	1,004	1,004	1,004	1,003	1,003	1,003	1,002	1,002	1,002	1,002	1,002	1,002
16	Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
	Annual Energy in Year 2006 (MWa)																
17	Native Load	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598
18	Pump Storage/Peak Return	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
19	Long Term Sales	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086
20	Short Term Sales	1,291	1,275	1,258	1,242	1,223	1,193	1,162	1,108	1,107	1,106	1,095	983	983	984	984	984
21	less DSM	(187)	(187)	(189)	(192)	(195)	(197)	(198)	(202)	(203)	(209)	(211)	(212)	(213)	(213)	(213)	(213)
22	**Total Requirements**	9,045	9,028	9,009	8,990	8,969	8,936	8,904	8,847	8,845	8,838	8,825	8,712	8,711	8,711	8,711	8,711
23	Existing Generation	7,689	7,693	7,705	7,714	7,727	7,751	7,779	7,799	7,807	7,810	7,814	7,847	7,847	7,847	7,847	7,847
24	Long Term Purchases	466	466	466	466	466	466	466	466	466	466	466	466	466	466	466	466
25	Short Term Purchases	358	364	359	358	361	362	368	375	374	376	377	390	390	390	390	390
26	New Resources																
27	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Cogeneration	532	505	478	452	415	357	291	207	198	186	167	-	-	-	-	-
29	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Peaking Resources	-	-	-	-	-	-	-	-	-	-	1	8	8	8	8	8
33	**Total Resources**	9,045	9,028	9,009	8,990	8,969	8,936	8,904	8,847	8,845	8,838	8,825	8,712	8,711	8,711	8,711	8,711
	Average Annual Emission in 1997-2046 (1000 tons)																
34	CO2	59,536	59,597	59,634	59,664	59,694	59,742	59,812	59,833	59,937	60,408	60,804	61,155	61,197	61,216	61,262	61,342
35	NOx	131.9	132.1	132.2	132.3	132.4	132.6	132.8	133.0	133.4	134.3	134.8	135.1	135.1	135.1	135.0	135.0
	Financial Results with End Effects to 2046																
36	50-year Utility Cost																
37	NPV at 7.9% (million $)	45,827	45,849	45,928	46,006	46,090	46,208	46,259	46,425	46,549	46,438	46,367	46,288	46,292	46,300	46,315	46,315
38	Real Levelized (mills/kWh)	41.83	41.81	41.91	41.98	42.07	42.18	42.22	42.44	42.55	42.50	42.43	42.36	42.37	42.37	42.39	42.39
39	50-year Total Resources Cost																
40	NPV at 7.9% (million $)	45,304	45,302	45,381	45,459	45,558	45,675	45,726	45,888	46,011	45,896	45,824	45,746	45,750	45,757	45,773	45,772
41	Real Levelized (mills/kWh)	39.95	39.95	40.02	40.09	40.17	40.28	40.32	40.46	40.57	40.47	40.41	40.34	40.34	40.35	40.36	40.36

Table 3 - 12

Sweep 2: Sensitivity less Base Case - Resource Selections by 2006, Emissions, and Financial Results
Gas Price Jump in 1998 by 0 to 200%, No Market Price Increase

	Base Case	5%	10%	15%	20%	25%	30%	40%	50%	70%	90%	110%	130%	150%	175%	200%
Case #	1	2-1	2-2	2-3	2-4	2-5	2-6	2-7	2-8	2-9	2-10	2-11	2-12	2-13	2-14	2-15
Summer Peak Capacity in Year 2006 (MW)																
1 Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2 Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 less DSM	-	-	(3)	(6)	(9)	(12)	(13)	(17)	(20)	(26)	(28)	(30)	(31)	(31)	(31)	(31)
4 Total Requirements	-	-	(3)	(6)	(9)	(12)	(13)	(17)	(20)	(26)	(28)	(30)	(31)	(31)	(31)	(31)
5 Existing Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Long Term Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7 New Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9 Cogeneration	-	(32)	(64)	(94)	(138)	(206)	(283)	(398)	(400)	(408)	(429)	(625)	(625)	(625)	(625)	(625)
10 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13 Peaking Resources	-	32	60	87	128	192	269	379	379	379	398	592	592	591	591	591
14 Total Resources	-	0	(5)	(8)	(11)	(15)	(15)	(20)	(22)	(29)	(31)	(34)	(34)	(34)	(35)	(35)
15 Reserves	-	-	-	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)
16 Reserve Margin (RM) (%)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Energy in Year 2006 (MWa)																
17 Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18 Pump Storage/Peak Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19 Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20 Short Term Sales	-	(17)	(34)	(49)	(68)	(99)	(130)	(183)	(184)	(185)	(196)	(308)	(308)	(308)	(308)	(308)
21 less DSM	-	(1)	(3)	(6)	(8)	(11)	(12)	(15)	(16)	(22)	(24)	(26)	(26)	(26)	(26)	(27)
22 Total Requirements	-	(17)	(37)	(55)	(76)	(109)	(141)	(198)	(200)	(207)	(220)	(333)	(334)	(334)	(334)	(334)
23 Existing Generation	-	4	16	25	38	62	90	110	118	121	125	158	158	158	158	158
24 Long Term Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Short Term Purchases	-	6	1	1	3	4	10	18	16	18	19	33	32	33	32	32
26 New Resources																
27 Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Cogeneration	-	(27)	(54)	(80)	(118)	(175)	(241)	(326)	(334)	(346)	(365)	(532)	(532)	(532)	(532)	(532)
29 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31 Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32 Peaking Resources	-	-	-	-	-	-	-	-	-	-	1	8	8	8	8	8
33 Total Resources	-	(17)	(37)	(55)	(76)	(109)	(141)	(198)	(200)	(207)	(220)	(333)	(334)	(334)	(334)	(334)
Average Annual Emission in 1997-2046 (1000 tons)																
34 CO_2	-	61	99	128	158	206	276	297	401	872	1,268	1,619	1,661	1,681	1,726	1,806
35 NO_x	-	0.2	0.3	0.4	0.5	0.7	0.9	1.1	1.5	2.3	2.9	3.2	3.2	3.2	3.1	3.1
Financial Results with End Effects to 2046																
36 50-year Utility Cost																
37 NPV at 7.9% (million $)	-	21	100	179	263	380	431	598	721	611	539	461	465	472	487	487
38 Real Levelized (mills/kWh)	-	(0.02)	0.08	0.15	0.24	0.35	0.39	0.61	0.72	0.67	0.60	0.53	0.54	0.54	0.56	0.56
39 50-year Total Resources Cost																
40 NPV at 7.9% (million $)	-	(2)	77	155	254	372	423	584	707	592	521	442	446	454	469	469
41 Real Levelized (mills/kWh)	-	(0.00)	0.07	0.14	0.22	0.33	0.37	0.52	0.62	0.52	0.46	0.39	0.39	0.40	0.41	0.41

Graph 3 - 13
Sweep 2: Cogeneration Resources Selected
Gas Price Jump in 1998 by 0 to 200%, No Market Price Increase



As in Sweep 1, the model ran coal-fired resources more heavily as gas prices increased. However, without the wholesale market price linkage, the model did not build new coal-fired plants as it did in Sweep 1, and it did not use the transmission option. As gas prices increased the model built more peaking resources, up to 712 MW. Without a wholesale market into which to sell excess production (because in this sweep the wholesale market price remained low in spite of gas price increases), peaking resources were more cost effective than were baseload resources, such as gas-fired cogeneration or coal-fired plants. Average emissions did not significantly vary, since coal was not a major addition.

The financial results show that a 1998 gas price jump without any commensurate wholesale market price increase would increase customer prices slightly. This is due to the lack of a gas/market linkage and the subsequent lack of short-term sales revenues to reduce the total revenue requirement.

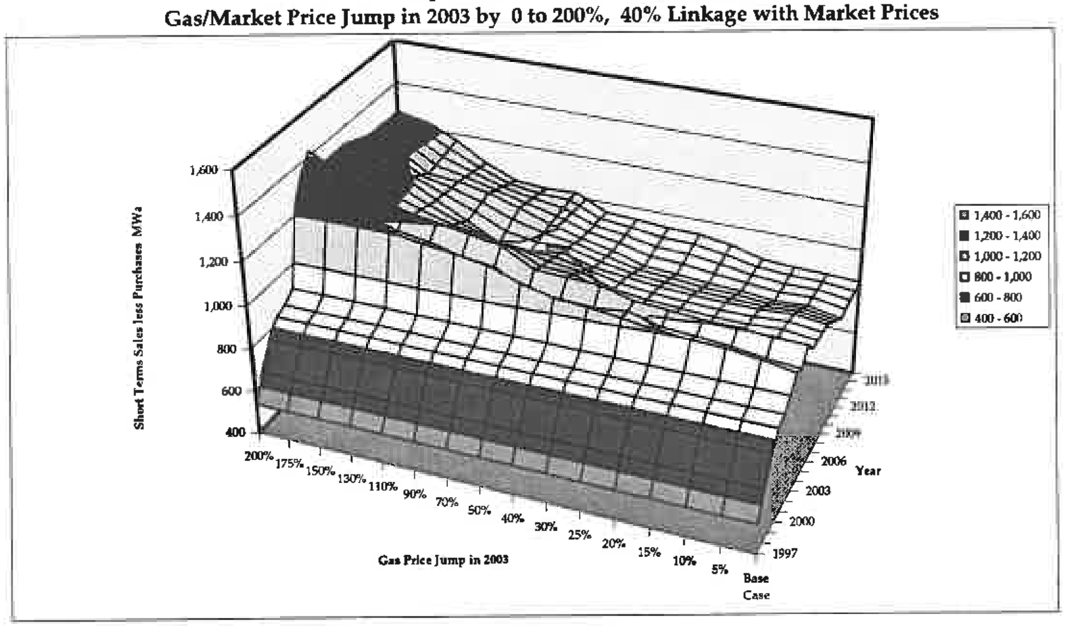
Sweep 3: Gas/Market Price Jump in 2003, 40 Percent Linkage

The third sweep is similar to the first, in that it assumed a gas price jump with a 40 percent linkage to wholesale market prices. While the price jump occurred in 1998 for Sweep 1, Sweep 3 assumed the jump occurred in 2003.

To accomplish the cases and sensitivities in Sweep 3, the company had to run the model in two stages, once without the gas price shock, to establish the resources the model would select up through and including the year 2003, thinking that gas prices would remain at the base case level, and a second time increasing the gas price in 2003. In the second run, the company forced in the resources the model had selected in the first run. From that point on the model could begin adjusting its subsequent resource selections based on the new higher gas price. These steps were necessary because IPM is a linear programming model, and thus cannot be surprised. If the company had used just one model run for each case with the higher gas prices beginning in 2003 in the inputs, the model would have known about them from the beginning and made adjustments beginning in 1998.

Sweep 3 varied the amount of the gas and wholesale market price jump by 0 to 200 percent, the same variation tested in Sweep 1. Because in Sweep 3 the company held the gas/market price linkage to 40 percent, the net short-term transactions remained relatively stable, except perhaps for a few years at the highest gas price jump. Graph 3-14 shows this pattern.

Graph 3 - 14
Sweep 3: Net Short Term Transactions
Gas/Market Price Jump in 2003 by 0 to 200%, 40% Linkage with Market Prices



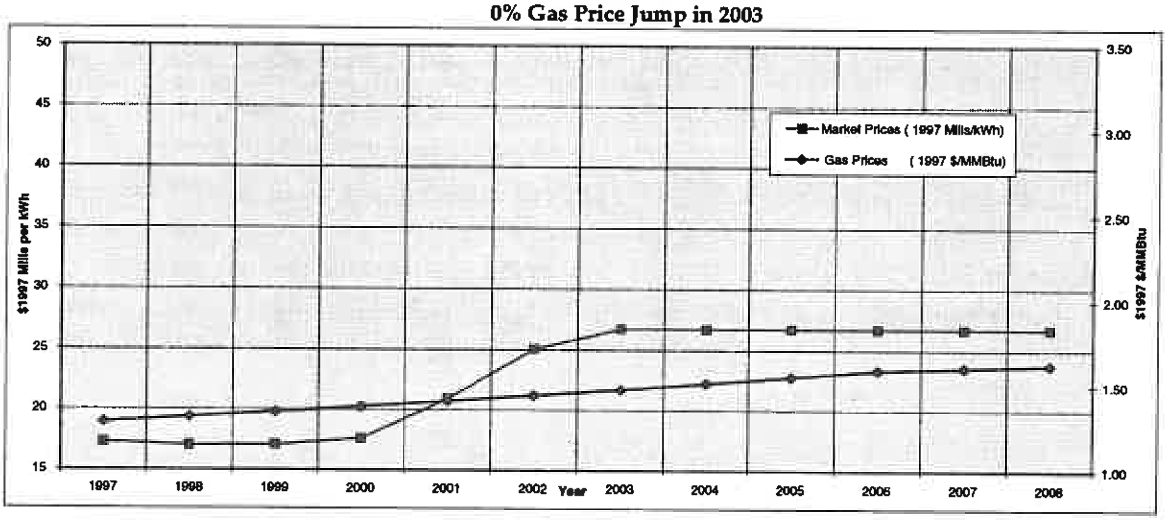
Graph 3-15 shows the pattern for gas and wholesale market prices for three of the sensitivities in Sweep 3: the base case (0 percent gas price jump), a gas price jump of 50 percent, and a gas price jump of 110 percent in 2003.

Graph 3 - 15

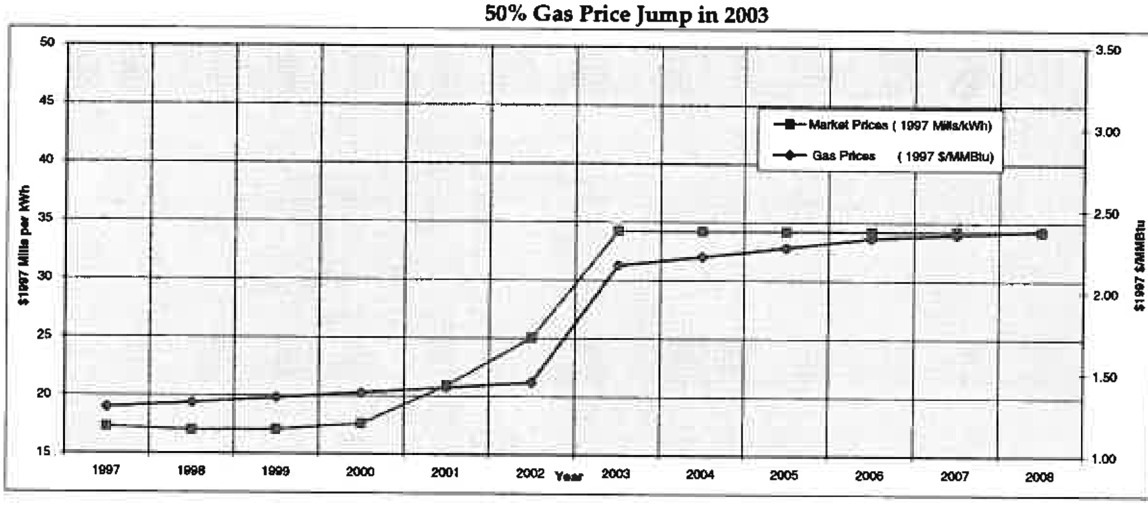
Sweep 3: Examples of Gas / Market Prices, 40% Linkage Between Gas and Market Prices

Gas / Market Price Jump in 2003 by 0 to 200%, 40% Linkage with Market Prices

0% Gas Price Jump in 2003



50% Gas Price Jump in 2003



110% Gas Price Jump in 2003

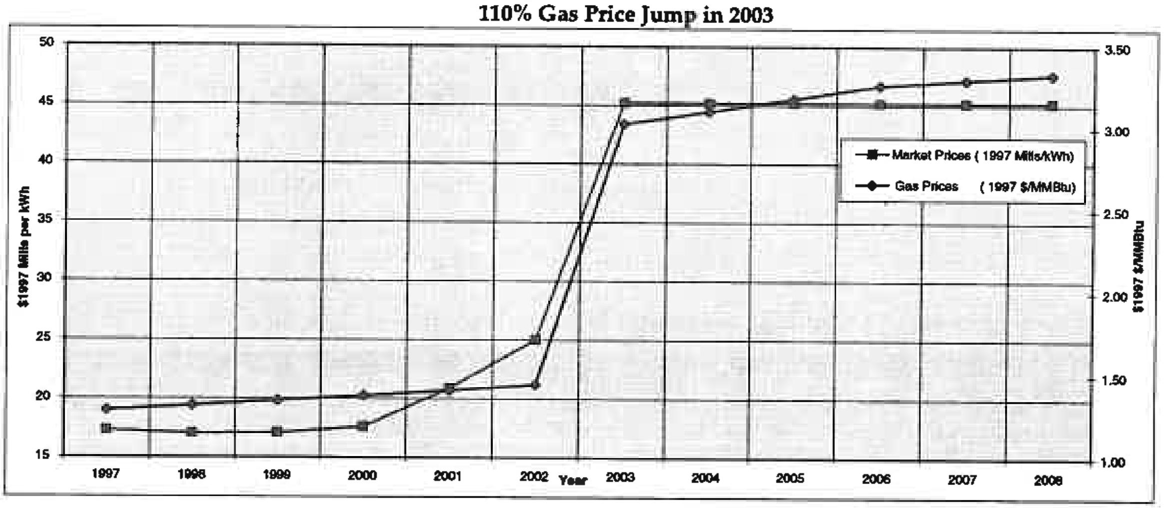


Table 3 - 16

Sweep 3: Resource Selections by 2006, Emissions, and Financial Results

Gas/Market Price Jump in 2003 by 0 to 200%, 40% Linkage with Market Prices

		0%	5%	10%	15%	20%	25%	30%	40%	50%	70%	90%	110%	130%	150%	175%	200%
	Case #	3-1	3-2	3-3	3-4	3-5	81	3-7	3-8	82	3-10	3-11	83	3-13	3-14	3-15	3-16
	Summer Peak Capacity in Year 2006 (MW)																
1	Native Load	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944
2	Long Term Sales	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362
3	less DSM	(254)	(254)	(255)	(256)	(256)	(257)	(257)	(258)	(258)	(260)	(261)	(261)	(261)	(262)	(262)	(262)
4	**Total Requirements**	10,052	10,052	10,051	10,050	10,050	10,049	10,049	10,048	10,048	10,046	10,045	10,045	10,045	10,044	10,044	10,044
5	Existing Generation	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,646	9,614	9,563	9,557	9,607	9,577
6	Long Term Purchase	658	658	658	658	658	658	658	658	658	658	658	658	658	658	658	658
7	New Resources																
8	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Cogeneration	625	629	597	566	561	547	540	547	548	539	529	517	466	385	385	385
10	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Coal	-	-	-	-	-	-	-	-	-	-	-	-	49	168	262	266
12	Transmission	-	-	-	-	-	-	-	-	-	-	7	39	90	95	46	76
13	Peaking Resources	121	117	149	178	182	197	203	195	194	200	209	222	224	186	91	88
14	**Total Resources**	11,058	11,057	11,057	11,055	11,055	11,054	11,054	11,053	11,053	11,051	11,050	11,050	11,050	11,049	11,049	11,050
15	Reserves	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,004	1,004	1,004	1,004	1,004	1,004
16	Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
	Annual Energy in Year 2006 (MWa)																
17	Native Load	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598
18	Pump Storage/Peak Return	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
19	Long Term Sales	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086
20	Short Term Sales	1,291	1,294	1,277	1,277	1,285	1,288	1,305	1,333	1,332	1,362	1,385	1,401	1,425	1,459	1,513	1,516
21	less DSM	(187)	(187)	(187)	(189)	(189)	(189)	(189)	(190)	(190)	(192)	(193)	(193)	(193)	(193)	(193)	(193)
22	**Total Requirements**	9,045	9,048	9,030	9,029	9,037	9,039	9,057	9,084	9,082	9,111	9,133	9,149	9,173	9,206	9,260	9,264
23	Existing Generation	7,689	7,704	7,723	7,748	7,766	7,785	7,799	7,851	7,867	7,944	7,969	7,955	7,936	7,931	7,975	7,960
24	Long Term Purchases	466	466	466	466	466	466	466	466	466	466	466	466	466	466	466	466
25	Short Term Purchases	358	343	333	334	327	323	322	281	275	241	240	251	248	243	213	200
26	New Resources																
27	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Cogeneration	532	535	508	482	478	465	469	486	474	460	451	441	397	328	328	328
29	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Coal	-	-	-	-	-	-	-	-	-	-	-	-	44	152	238	241
31	Transmission	-	-	-	-	-	-	-	-	-	-	6	35	81	86	42	69
32	Peaking Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	**Total Resources**	9,045	[illegible]	[illegible]	[illegible]	9,037	[illegible]	[illegible]	[illegible]	[illegible]	9,111	9,133	9,149	9,173	[illegible]	9,260	[illegible]
	Average Annual Emission in 1997-2046 (1000 tons)																
34	CO_2	59,536	59,631	59,679	59,746	59,813	59,895	59,910	60,046	60,191	60,833	61,515	61,878	62,235	62,567	62,905	63,028
35	NO_x	131.9	132.2	132.4	132.6	132.9	133.2	133.3	133.8	134.3	135.3	136.1	136.6	137.0	137.3	137.5	137.7
	Financial Results with End Effects to 2046																
36	50-year Utility Cost																
37	NPV at 7.9% (million $)	45,827	45,779	45,799	45,801	45,809	45,816	45,827	45,820	45,801	45,426	45,019	44,717	44,407	44,060	43,475	43,142
38	Real Levelized (mills/kWh)	41.83	41.79	41.81	41.78	41.79	41.80	41.82	41.82	41.81	41.46	41.09	40.82	40.53	40.22	39.68	39.38
39	50-year Total Resources Cost																
40	NPV at 7.9% (million $)	45,304	45,255	45,275	45,274	45,282	45,289	45,280	45,288	45,269	44,894	44,487	44,185	43,874	43,578	42,943	42,610
41	Real Levelized (mills/kWh)	39.95	39.91	39.92	39.92	39.93	39.94	39.93	39.94	39.92	39.59	39.23	38.96	38.69	38.38	37.87	37.57

Table 3 - 17

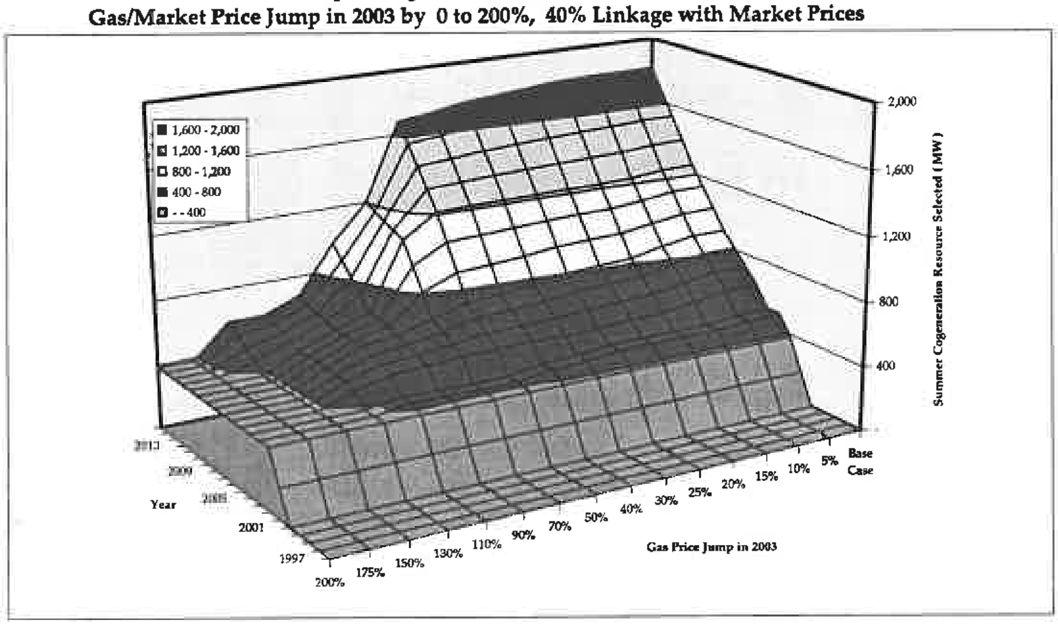
Sweep 3: Sensitivity less Base Case - Resource Selections by 2006, Emissions, and Financial Results

Gas/Market Price Jump in 2003 by 0 to 200%, 40% Linkage with Market Prices

		0%	5%	10%	15%	20%	25%	30%	40%	50%	70%	90%	110%	130%	150%	175%	200%
	Case #	3-1	3-2	3-3	3-4	3-5	81	3-7	3-8	82	3-10	3-11	83	3-13	3-14	3-15	3-16
	Summer Peak Capacity in Year 2006 (MW)																
1	Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	less DSM	-	-	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(6)	(7)	(7)	(7)	(8)	(8)	(8)
4	**Total Requirements**	-	-	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(6)	(7)	(7)	(7)	(8)	(8)	(8)
5	Existing Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Long Term Purchase	-	-	-	-	-	-	-	-	-	-	(7)	(39)	(90)	(96)	(46)	(76)
7	New Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Cogeneration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Combined Cycle CT	-	4	(29)	(59)	(64)	(79)	(85)	(78)	(78)	(86)	(96)	(108)	(159)	(240)	(240)	(240)
11	Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	49	168	262	266
13	Peaking Resources	-	(4)	28	57	61	76	82	74	73	79	7	39	90	95	46	76
14	**Total Resources**	-	(1)	(1)	(3)	(3)	(4)	(4)	(5)	(5)	(7)	88	100	103	65	(30)	(34)
												(8)	(9)	(8)	(9)	(9)	(9)
15	Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Reserve Margin (RM) (%)	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	(1)	(1)
	Annual Energy in Year 2006 (MWa)																
17	Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Pump Storage/Peak Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Short Term Sales	-	3	(15)	(14)	(6)	(3)	14	42	41	71	94	110	134	167	222	225
21	less DSM	-	(0)	(1)	(2)	(2)	(2)	(3)	(3)	(4)	(5)	(6)	(6)	(6)	(6)	(6)	(6)
22	**Total Requirements**	-	3	(15)	(16)	(9)	(6)	12	38	37	65	88	104	128	161	215	219
23	Existing Generation	-	15	34	59	77	96	110	162	177	255	280	266	247	242	286	271
24	Long Term Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Short Term Purchases	-	(15)	(25)	(24)	(31)	(34)	(36)	(77)	(83)	(117)	(118)	(107)	(110)	(115)	(145)	(158)
26	New Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Cogeneration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Combined Cycle CT	-	3	(24)	(51)	(54)	(67)	(63)	(47)	(58)	(72)	(81)	(91)	(135)	(204)	(204)	(204)
30	Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	44	152	238	241
32	Peaking Resources	-	-	-	-	-	-	-	-	-	-	6	35	81	86	42	69
33	**Total Resources**	-	3	(15)	(16)	(9)	(6)	12	38	37	65	88	104	128	161	215	219
	Average Annual Emission in 1997-2046 (1000 tons)																
34	CO2	-	95	144	210	277	359	374	510	655	1,298	1,980	2,342	2,699	3,031	3,369	3,493
35	NOx	-	0.3	0.5	0.7	0.9	1.2	1.4	1.9	2.4	3.4	4.2	4.7	5.1	5.4	5.6	5.8
	Financial Results with End Effects to 2046																
36	50-year Utility Cost																
37	NPV at 7.9% (million $)	-	(49)	(29)	(27)	(19)	(11)	(1)	(7)	(26)	(401)	(808)	(1,110)	(1,421)	(1,767)	(2,352)	(2,685)
38	Real Levelized (mills/kWh)	-	(0.04)	(0.02)	(0.05)	(0.04)	(0.03)	(0.01)	(0.01)	(0.02)	(0.37)	(0.74)	(1.01)	(1.30)	(1.61)	(2.15)	(2.45)
39	50-year Total Resources Cost																
40	NPV at 7.9% (million $)	-	(49)	(29)	(30)	(22)	(15)	(24)	(16)	(35)	(410)	(817)	(1,119)	(1,429)	(1,776)	(2,361)	(2,694)
41	Real Levelized (mills/kWh)	-	(0.04)	(0.03)	(0.03)	(0.02)	(0.01)	(0.02)	(0.01)	(0.03)	(0.36)	(0.72)	(0.99)	(1.26)	(1.57)	(2.08)	(2.38)

Table 3-16 shows the resource selections, emissions, and financial results at the tenth year. Table 3-17 shows these results as differences from the base case. As with Sweep 1, increasing the price for natural gas increased the amount of DSM. Also consistent with Sweep 1, the higher the gas/market price jump, the less gas-fired cogeneration the model added. Graph 3-18 shows this pattern.

Graph 3 - 18
Sweep 3: Cogeneration Resources Selected
Gas/Market Price Jump in 2003 by 0 to 200%, 40% Linkage with Market Prices



At gas price jumps of 70 percent or more, the model began building new coal-fired resources in 2010 (this occurred in 2009 in Sweep 1) and at gas price jumps of 110 percent or more, it began building new coal-fired resources in 2007 (this occurred in 2003 in Sweep 1). Graph 3-19 shows these results. At gas price jumps of 130 percent or more it also used the transmission option. As gas/market prices increased the model built more peaking resources, but at the highest price jumps abandoned them in favor of coal-fired plants. This is because the peaking resources are gas fired and thus less cost effective as gas prices increased. Average emissions did not vary significantly until gas prices jumped by 130 percent or more, and the model built more coal-fired plants.

The financial results show that a gas/market price jump in 2003 would not hurt customers. In fact, customer prices would decrease slightly as the gas and wholesale market prices increase. This is due to the increased wholesale revenues the company would gain as wholesale market prices increased.

Graph 3 - 19
Sweep 3: Coal Resources Selected (MW)
Gas/Market Price Jump in 2003 by 0 to 200%, 40% Linkage with Market Prices

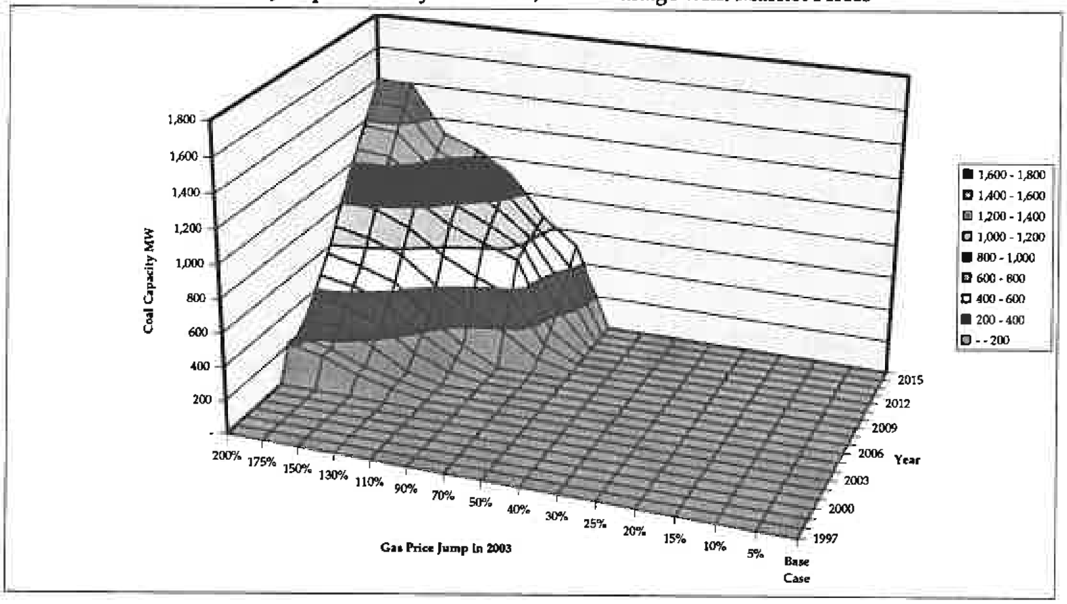


Table 3-20 shows the difference in results for the cases included in Sweep 1 and those in Sweep 3. Since both sweeps used the same percentage price jumps, and the same wholesale market linkage (40 percent), the only difference is the timing of the price jump (1998 for Sweep 1 and 2003 for Sweep 3). A gas/market price jump in 1998 caused more DSM than if the price jump occurred later; it also caused less selection of cogeneration, more selection of coal, more use of the transmission option, and slightly more selection of peaking resources. Emissions tend to be more if the gas price jump is in 1998 rather than 2003, since the model then selects more coal-fired resources. However, customers benefit more from revenues gained by selling unused energy on the wholesale market under the assumption of an earlier gas price jump, because then the model builds more coal-fired resources, providing more of the unused energy. If the model had more time to adjust to the higher gas prices, it could make more cost effective choices for a higher gas-price environment.

Table 3 - 20
Sweep 3: Gas/Market Price Jump in 2003 by 0 to 200% (Sweep 3) LESS Gas/Market Price Jump in 1998 by 0 to 200% (Sweep 1)
Gas/Market Price Jump in 2003 by 0 to 200%, 40% Linkage with Market Prices

		0%	5%	10%	15%	20%	25%	30%	40%	50%	70%	90%	110%	130%	150%	175%	200%
	Case #	3-1	3-2	3-3	3-4	3-5	81	3-7	3-8	82	3-10	3-11	83	3-13	3-14	3-15	3-16
	Summer Peak Capacity in Year 2006 (MW)																
1	Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	less DSM	-	-	2	4	8	9	11	13	18	22	24	25	27	26	28	28
4	**Total Requirements**	-	-	2	4	8	9	11	13	18	22	24	25	27	26	28	28
5	Existing Generation	-	-	-	-	-	-	-	-	-	35	181	234	136	90	209	225
6	Long Term Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	New Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Cogeneration	-	0	2	4	3	3	7	28	49	119	156	315	264	183	322	385
10	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Coal	-	-	-	-	-	-	-	-	-	-	-	(190)	(213)	(169)	(256)	(347)
12	Transmission	-	-	-	-	-	-	-	-	-	(35)	(179)	(231)	(134)	(90)	(207)	(222)
13	Peaking Resources	-	(1)	(0)	0	5	8	5	(13)	(30)	(96)	(132)	(100)	(23)	14	(37)	(9)
14	**Total Resources**	-	(1)	2	3	8	10	12	16	21	25	28	27	30	28	31	32
15	Reserves	-	-	-	-	1	1	1	2	2	3	2	2	2	2	2	3
16	Reserve Margin (RM) (%)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Annual Energy in Year 2006 (MWa)																
17	Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Pump Storage/Peak Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Short Term Sales	-	(7)	(13)	(9)	4	(12)	12	(6)	6	39	58	50	13	5	26	(17)
21	less DSM	-	0	2	4	7	9	9	12	16	20	21	23	24	24	25	26
22	**Total Requirements**	-	(7)	(11)	(5)	11	(3)	21	6	21	59	79	72	37	29	51	8
23	Existing Generation	-	0	(2)	(10)	0	(1)	(2)	1	(11)	11	136	193	123	82	183	193
24	Long Term Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Short Term Purchases	-	(7)	(11)	1	8	(5)	15	(14)	(7)	(22)	(26)	(6)	5	27	17	8
26	New Resources																
27	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Cogeneration	-	0	2	3	2	2	8	19	40	101	132	268	224	155	274	328
29	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Coal	-	-	-	-	-	-	-	-	-	-	-	(172)	(193)	(154)	(235)	(318)
31	Transmission	-	-	-	-	-	-	-	-	-	(32)	(162)	(210)	(122)	(81)	(188)	(202)
32	Peaking Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	**Total Resources**	-	(7)	(11)	(5)	11	(3)	21	6	21	59	79	72	37	29	51	8
	Average Annual Emission in 1997-2046 (1000 tons)																
34	CO_2	-	(51)	(98)	(168)	(167)	(164)	(206)	(174)	(228)	(302)	(324)	(856)	(1,082)	(971)	(1,158)	(1,682)
35	NOx	-	(0.2)	(0.3)	(0.6)	(0.6)	(0.7)	(0.7)	(0.8)	(1.0)	(1.3)	(1.4)	(1.9)	(2.1)	(2.1)	(2.3)	(2.7)
	Financial Results with End Effects to 2046																
36	50-year Utility Cost																
37	NPV at 7.9% (million $)	-	27	60	80	110	121	167	187	230	389	510	673	993	1,199	1,373	1,775
38	Real Levelized (mills/kWh)	-	0.06	0.07	0.06	0.08	0.09	0.08	0.11	0.14	0.24	0.33	0.49	0.77	0.96	1.12	1.49
39	50-year Total Resources Cost																
40	NPV at 7.9% (million $)	-	50	83	100	116	126	157	192	233	399	512	675	994	1,200	1,374	1,776
41	Real Levelized (mills/kWh)	-	0.04	0.07	0.09	0.10	0.11	0.14	0.17	0.21	0.35	0.45	0.60	0.88	1.06	1.21	1.57

Sweep 4: Gas/Market Price Jump 1998, 0 - 100 Percent Linkage

The fourth sweep increased the price of gas in 1998 by 70 percent, while allowing the linkage with wholesale market prices to vary from 0 to 100 percent. This sweep provides a picture of the impact of alternative linkages between natural gas prices and wholesale market prices.

Graph 3-21 shows the impact on net short-term transactions. At no linkage, purchases were much larger than sales, because gas prices increased when wholesale market prices did not. The model purchased off the wholesale market rather than building new resources and selling any excess energy. At a 100 percent linkage, sales were much larger than purchases, because wholesale market prices were increasing along with gas prices. This caused the model to build more resources to sell excess energy into this high-priced wholesale market.

Graph 3 - 21
Sweep 4: Net Short-Term Transactions
70% Gas Price Jump in 1998, 0 to 100% Linkage with Market Prices

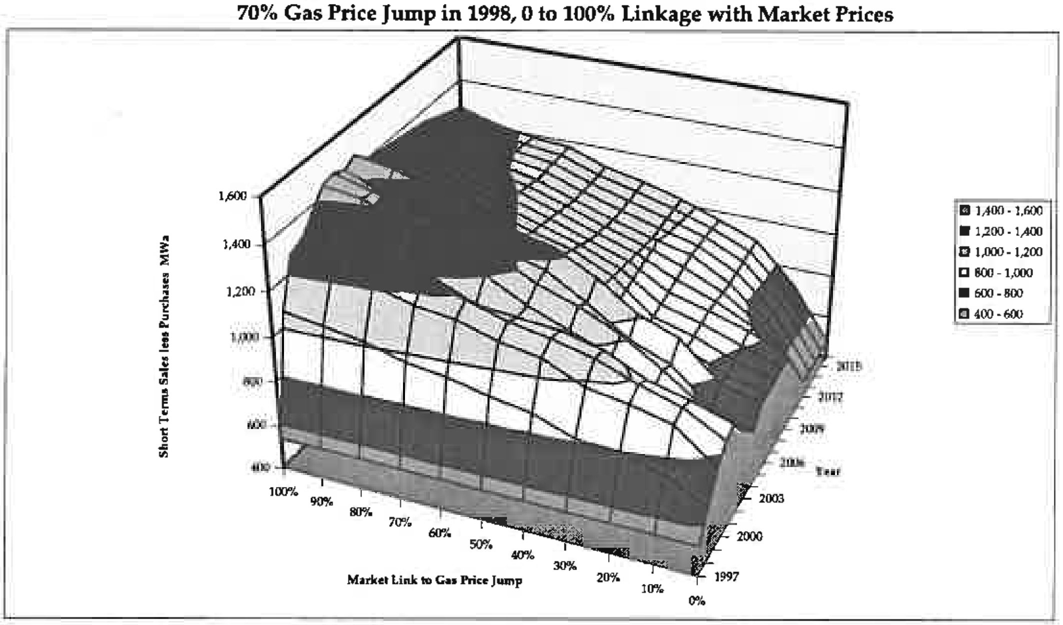


Table 3-22 shows the results of resource selections for Sweep 4 after the tenth year. Table 3-23 shows the difference in results for each case after subtracting off the results for the base case. Line 20 (short-term sales) and line 25 (short-term purchases) on Table 3-22 shows the impact of varying the degree of gas/market price linkage. The greater the linkage, the higher the level of short-term sales shown on line 20, and the lower the level of short-term purchases shown on line 25.

Table 3 - 22
Sweep 4: Resource Selections by 2006, Emissions, and Financial Results
70% Gas Price Jump in 1998, 0 to 100% Linkage with Market Prices

		0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
	Case #	4-1	4-2	4-3	4-4	4-5	4-6	4-7	4-8	4-9	4-10	4-11
	Summer Peak Capacity in Year 2006 (MW)											
1	Native Load	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944
2	Long Term Sales	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362
3	less DSM	(280)	(281)	(281)	(281)	(282)	(283)	(282)	(282)	(282)	(282)	(281)
4	**Total Requirements**	10,026	10,025	10,025	10,025	10,024	10,023	10,024	10,024	10,024	10,024	10,025
5	Existing Generation	9,653	9,653	9,653	9,634	9,618	9,619	9,649	9,653	9,653	9,653	9,653
6	Long Term Purchase	658	658	658	658	658	658	658	658	658	658	658
7	New Resources											
8	Renewable	-	-	-	-	-	-	-	-	-	-	-
9	Cogeneration	218	217	217	267	421	497	532	573	627	716	716
10	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-
11	Coal	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	19	35	34	4	-	-	-	-
13	Peaking Resources	500	500	500	450	296	219	183	142	88	-	-
14	**Total Resources**	11,029	11,028	11,028	11,028	11,027	11,026	11,026	11,026	11,026	11,027	11,027
15	**Reserves**	1,003	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002
16	Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
	Annual Energy in Year 2006 (MWa)											
17	Native Load	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598
18	Pump Storage/Peak Return	257	257	257	257	257	257	257	257	257	257	257
19	Long Term Sales	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086
20	Short Term Sales	1,094	1,120	1,180	1,217	1,323	1,384	1,425	1,464	1,526	1,581	1,592
21	less DSM	(209)	(209)	(210)	(211)	(211)	(212)	(212)	(212)	(212)	(212)	(212)
22	**Total Requirements**	8,826	8,851	8,910	8,946	9,052	9,113	9,153	9,193	9,235	9,310	9,321
23	Existing Generation	7,810	7,841	7,920	7,909	7,933	7,952	7,986	7,998	8,008	8,003	8,014
24	Long Term Purchases	466	466	466	466	466	466	466	466	466	466	466
25	Short Term Purchases	364	354	333	320	262	231	235	221	210	192	191
26	New Resources											
27	Renewable	-	-	-	-	-	-	-	-	-	-	-
28	Cogeneration	186	190	191	234	359	433	463	507	571	649	650
29	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-
30	Coal	-	-	-	-	-	-	-	-	-	-	-
31	Transmission	-	-	-	18	32	31	4	-	-	-	-
32	Peaking Resources	-	-	-	-	-	-	-	-	-	-	-
33	**Total Resources**	[illegible]	[illegible]	8,910	[illegible]	[illegible]	9,113	9,153	9,193	[illegible]	[illegible]	[illegible]
	Average Annual Emission in 1997-2046 (1000 tons)											
34	CO_2	60,408	60,567	60,712	60,916	61,136	61,267	61,409	61,498	61,604	61,659	61,757
35	NO_x	134.3	134.7	135.2	135.8	136.5	137.0	137.4	137.7	137.9	138.1	138.2
	Financial Results with End Effects to 2046											
36	50-year Utility Cost											
37	NPV at 7.9% (million $)	46,438	46,136	45,804	45,428	45,037	44,648	44,269	43,885	43,470	43,052	42,561
38	Real Levelized (mills/kWh)	42.50	42.22	41.92	41.58	41.18	40.82	40.48	40.13	39.75	39.37	38.92
39	50-year Total Resources Cost											
40	NPV at 7.9% (million $)	45,896	45,594	45,261	44,886	44,492	44,103	43,723	43,340	42,925	42,507	42,016
41	Real Levelized (mills/kWh)	40.47	40.21	39.91	39.58	39.23	38.89	38.56	38.22	37.85	37.48	37.05

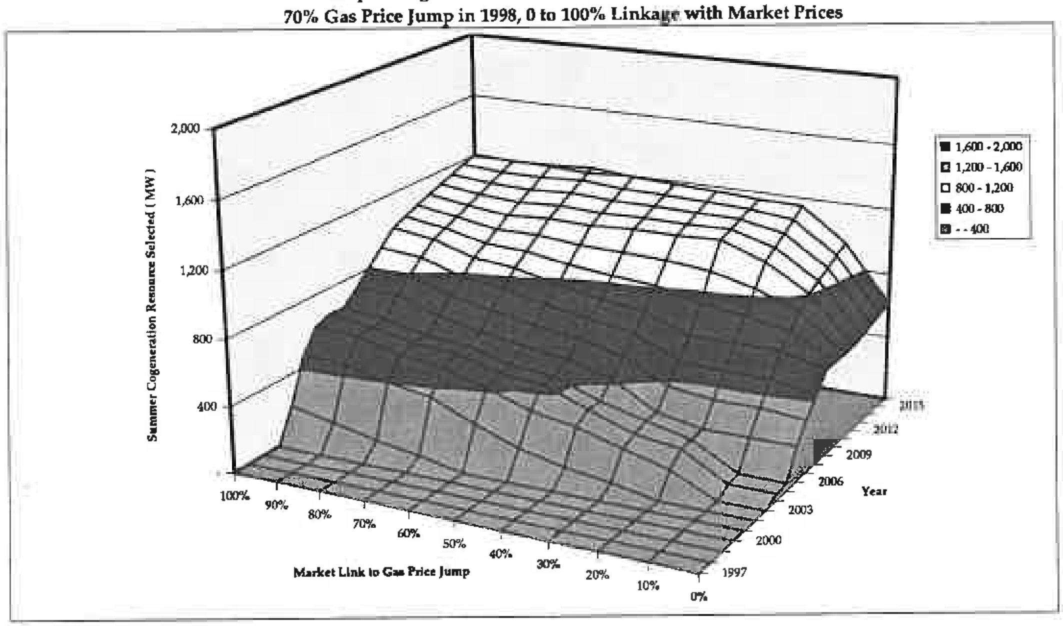
Table 3 - 23

Sweep 4: Sensitivity less Base Case - Resource Selections by 2006, Emissions, and Financial Results
70% Gas Price Jump in 1998, 0 to 100% Linkage with Market Prices

		0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
	Case #	4-1	4-2	4-3	4-4	4-5	4-6	4-7	4-8	4-9	4-10	4-11
	Summer Peak Capacity in Year 2006 (MW)											
1	Native Load	-	-	-	-	-	-	-	-	-	-	-
2	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-
3	less DSM	(26)	(27)	(27)	(27)	(28)	(29)	(28)	(28)	(28)	(28)	(27)
4	**Total Requirements**	**(26)**	**(27)**	**(27)**	**(27)**	**(28)**	**(29)**	**(28)**	**(28)**	**(28)**	**(28)**	**(27)**
5	Existing Generation	-	-	-	(19)	(35)	(34)	(4)	-	-	-	-
6	Long Term Purchase	-	-	-	-	-	-	-	-	-	-	-
7	New Resources	-	-	-	-	-	-	-	-	-	-	-
8	Renewable	-	-	-	-	-	-	-	-	-	-	-
9	Cogeneration	(408)	(408)	(409)	(359)	(205)	(129)	(93)	(52)	2	90	91
10	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-
11	Coal	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	19	35	34	4	-	-	-	-
13	Peaking Resources	379	379	379	329	175	97	62	21	(33)	(121)	(121)
14	**Total Resources**	**(29)**	**(30)**	**(30)**	**(31)**	**(31)**	**(33)**	**(32)**	**(32)**	**(32)**	**(31)**	**(31)**
15	Reserves	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
16	Reserve Margin (RM) (%)	-	-	-	-	-	-	-	-	-	-	-
	Annual Energy in Year 2006 (MWa)											
17	Native Load	-	-	-	-	-	-	-	-	-	-	-
18	Pump Storage/Peak Return	-	-	-	-	-	-	-	-	-	-	-
19	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-
20	Short Term Sales	(197)	(171)	(112)	(75)	32	93	134	173	235	290	301
21	less DSM	(22)	(23)	(23)	(25)	(25)	(26)	(26)	(26)	(26)	(25)	(25)
22	**Total Requirements**	**(219)**	**(194)**	**(135)**	**(99)**	**7**	**67**	**108**	**147**	**209**	**265**	**276**
23	Existing Generation	121	152	231	220	244	263	297	309	318	314	325
24	Long Term Purchases	-	-	-	-	-	-	-	-	-	-	-
25	Short Term Purchases	6	(4)	(25)	(38)	(96)	(127)	(123)	(136)	(148)	(166)	(167)
26	New Resources											
27	Renewable	-	-	-	-	-	-	-	-	-	-	-
28	Cogeneration	(346)	(342)	(341)	(299)	(173)	(99)	(69)	(25)	39	117	118
29	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-
30	Coal	-	-	-	-	-	-	-	-	-	-	-
31	Transmission	-	-	-	18	32	31	4	-	-	-	-
32	Peaking Resources	-	-	-	-	-	-	-	-	-	-	-
33	**Total Resources**	**(219)**	**(194)**	**(135)**	**(99)**	**7**	**67**	**108**	**147**	**209**	**265**	**276**
	Average Annual Emission in 1997-2046 (1000 tons)											
34	CO_2	872	1,031	1,176	1,380	1,600	1,732	1,873	1,963	2,068	2,123	2,221
35	NO_x	2.3	2.8	3.3	3.9	4.6	5.1	5.5	5.8	6.0	6.2	6.3
	Financial Results with End Effects to 2046											
36	50-year Utility Cost											
37	NPV at 7.9% (million $)	611	308	(24)	(399)	(790)	(1,179)	(1,559)	(1,942)	(2,357)	(2,775)	(3,267)
38	Real Levelized (mills/kWh)	0.67	0.39	0.09	(0.25)	(0.65)	(1.01)	(1.35)	(1.70)	(2.08)	(2.46)	(2.91)
39	50-year Total Resources Cost											
40	NPV at 7.9% (million $)	592	290	(42)	(417)	(812)	(1,201)	(1,580)	(1,964)	(2,379)	(2,797)	(3,288)
41	Real Levelized (mills/kWh)	0.52	0.26	(0.04)	(0.37)	(0.72)	(1.06)	(1.39)	(1.73)	(2.10)	(2.47)	(2.90)

The degree of gas/market linkage seems to have had no impact on DSM levels. The greater the linkage, the more cogeneration the model selected, and the less peaking resources. Graph 3-24 shows the cogeneration results. Since cogeneration is a baseload resource, higher wholesale market prices make it more cost effective because of the revenue the model gains from selling excess energy on the short-term wholesale market.

Graph 3 - 24
Sweep 4: Cogeneration Resources Selected
70% Gas Price Jump in 1998, 0 to 100% Linkage with Market Prices



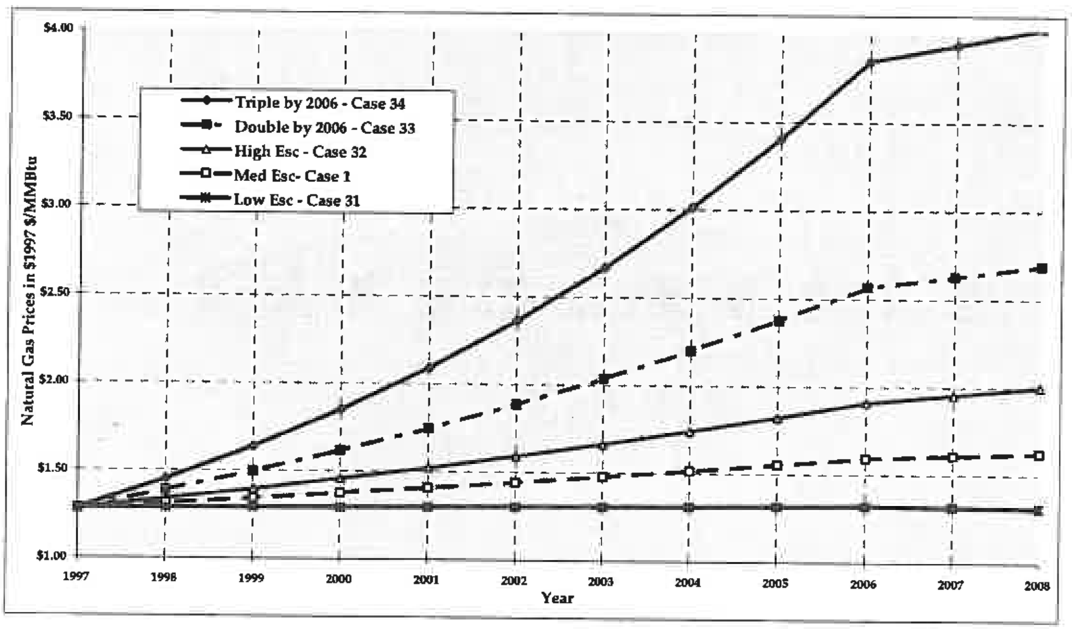
Emissions were not significantly affected in this sweep. The financial results show a definite benefit to customers from a greater linkage with wholesale market prices. From a high of 42.5 mills at zero linkage, real levelized mills/kWh decreased to 38.92 at 100 percent linkage. The base case, with a 40 percent linkage and no gas price increase, had real levelized prices at 41.83 mills/kWh.

Sweep 5: Gas Escalation From Low to Triple by 2006

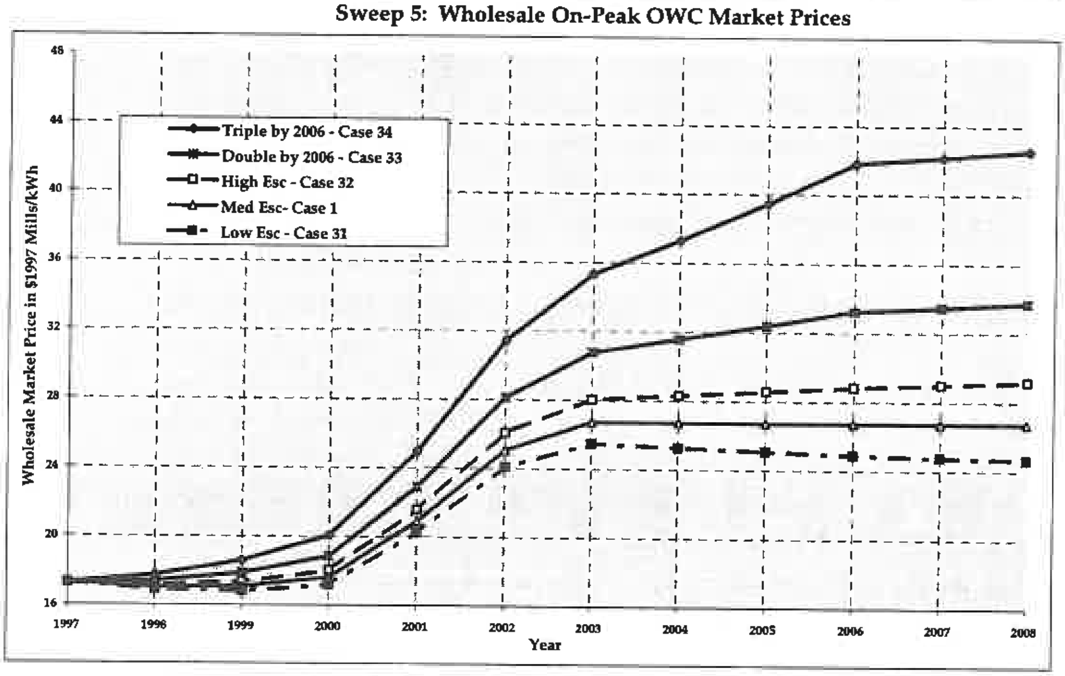
The first four sweeps caused gas prices to take a one-time jump, but kept the escalation rates the same before and after the jump. The fifth sweep varied the year-by-year gas escalation. The five cases in Sweep 5 vary the gas price annual escalation rate: 0.3 percent in case 31, 2.4 percent in case 1, 4.5 percent in case 32, 8.0 percent in case 33 (Double by 2006), and 13 percent in case 34 (Triple by 2006). In all five cases in this sweep, the price escalation level decreased dramatically after 2006.

Graph 3-25 shows the pattern of both gas and wholesale market price escalation for each of the five cases included in Sweep 5. Wholesale market prices have a 40 percent linkage to gas price increases in all of the cases in Sweep 5. Because of the 40 percent linkage, wholesale market price escalation changed with each case in Sweep 5. Graph 3-26 shows the impact on net short-term transactions for the cases in Sweep 5. The 40 percent market linkage keeps net short-term transactions at a relatively consistent level.

Graph 3 - 25
Sweep 5: Examples of Gas / Market Prices,
Gas Escalation from Low to Triple the Beginning Price by 2006



Sweep 5: Wholesale On-Peak OWC Market Prices



Graph 3 - 26
Sweep 5: Net Short-Term Transactions
Gas Escalation from Low to Triple the Beginning Price by 2006

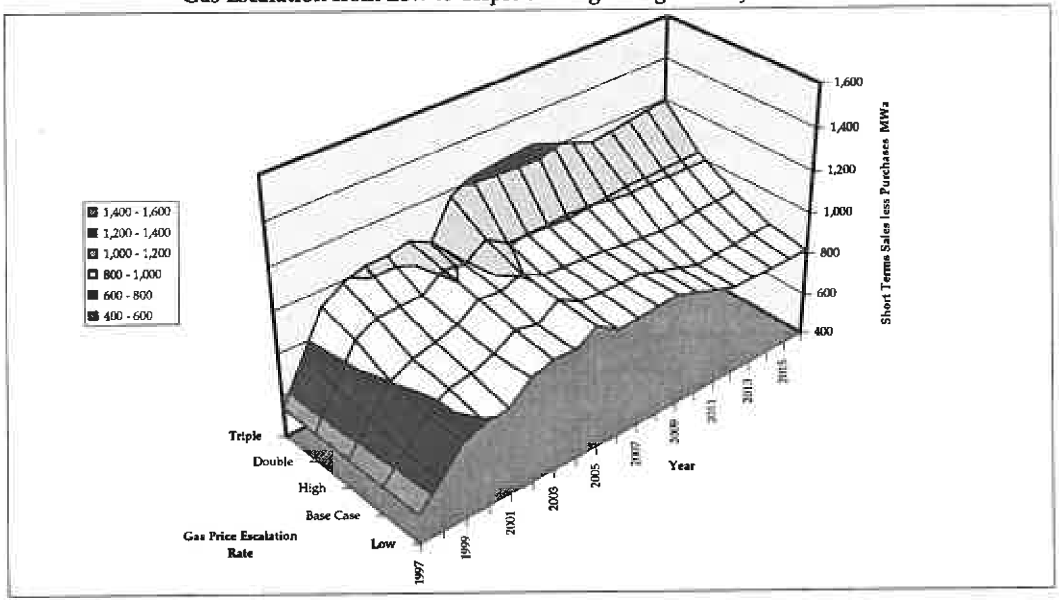


Table 3-27 shows the resource selections by 2006, emissions and financial results for Sweep 5. Table 3-28 shows the differences for each sensitivity from the base case. Consistent with a pattern already established in the previous sweeps, when the wholesale market price increased, short-term sales increased and short-term purchases decreased. In Sweep 5, the higher the gas and wholesale market price escalation, the higher the level of short-term sales (shown on line 20 of Table 3-27) and the lower the level of short-term purchases (line 25).

As with previous sweeps that dramatically increased the price of gas, high gas prices result in increased DSM. The higher the price of gas, the fewer new gas-fired resources the model selects. This is shown on Graph 3-29. At low gas price escalation, the model selected 762 MW of new gas-fired resources in the first ten years, which decreased to 202 MW in the triple case. As with previous sweeps the model selected coal-fired resources at the higher gas price levels, Graph 3-30 illustrates this pattern. At higher gas price levels, with the associated higher levels of coal-fired resources, emission levels increased.

Higher gas prices reduced customer prices because of the concurrent impact on wholesale market prices. The higher wholesale market prices allowed the model to offset costs with increased revenues from selling excess energy on the short-term wholesale market.

Table 3 - 27
Sweep 5: Resource Selections by 2006, Emissions, and Financial Results
Gas Escalation From Low to Triple the Beginning Price by 2006

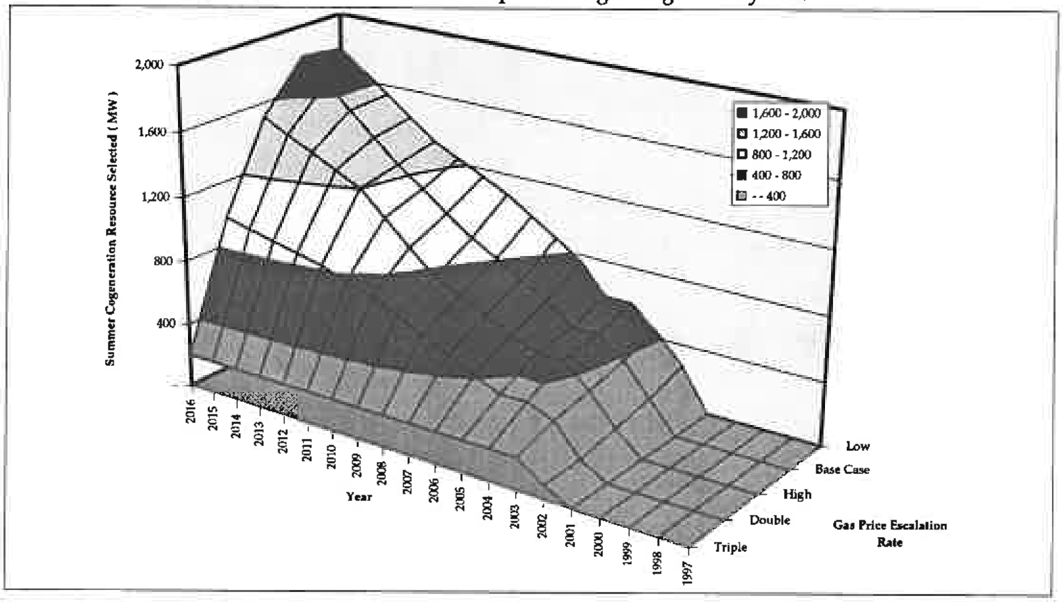
		Low Escalation	Base Case	High Escalation	Double by 2006	Triple by 2006
	Case #	31	1	32	33	34
	Summer Peak Capacity in Year 2006 (MW)					
1	Native Load	8,944	8,944	8,944	8,944	8,944
2	Long Term Sales	1,362	1,362	1,362	1,362	1,362
3	less DSM	(240)	(254)	(268)	(281)	(287)
4	**Total Requirements**	10,066	10,052	10,038	10,025	10,019
5	Existing Generation	9,653	9,653	9,653	9,618	9,442
6	Long Term Purchase	658	658	658	658	658
7	New Resources					
8	Renewable	-	-	-	-	-
9	Cogeneration	762	625	539	410	202
10	Combined Cycle CT	-	-	-	-	-
11	Coal	-	-	-	-	317
12	Transmission	-	-	-	35	209
13	Peaking Resources	-	121	192	307	193
14	**Total Resources**	11,073	11,058	11,042	11,028	11,021
15	Reserves	1,007	1,005	1,004	1,002	1,002
16	Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.0
	Annual Energy in Year 2006 (MWa)					
17	Native Load	6,598	6,598	6,598	6,598	6,598
18	Pump Storage/Peak Return	257	257	257	257	257
19	Long Term Sales	1,086	1,086	1,086	1,086	1,086
20	Short Term Sales	1,269	1,291	1,264	1,282	1,436
21	less DSM	(174)	(187)	(199)	(211)	(216)
22	**Total Requirements**	9,036	9,045	9,005	9,012	9,160
23	Existing Generation	7,485	7,689	7,771	7,886	7,828
24	Long Term Purchases	466	466	466	466	466
25	Short Term Purchases	359	358	310	278	216
26	New Resources					
27	Renewable	-	-	-	-	-
28	Cogeneration	726	532	458	350	173
29	Combined Cycle CT	-	-	-	-	-
30	Coal	-	-	-	-	288
31	Transmission	-	-	-	32	190
32	Peaking Resources	-	-	-	-	-
33	**Total Resources**	9,036	9,045	9,005	9,012	9,160
	Average Annual Emission in 1997-2046 (1000 tons)					
34	CO_2	58,889	59,536	60,015	61,162	63,173
35	NO_x	129.6	131.9	133.5	135.7	138.2
	Financial Results with End Effects to 2046					
36	50-year Utility Cost					
37	NPV at 7.9% (million $)	45,860	45,827	45,592	44,957	43,136
38	Real Levelized (mills/kWh)	41.70	41.83	41.68	41.14	39.51
39	50-year Total Resources Cost					
40	NPV at 7.9% (million $)	45,338	45,304	45,055	44,415	42,602
41	Real Levelized (mills/kWh)	39.98	39.95	39.73	39.17	37.57

Table 3 - 28

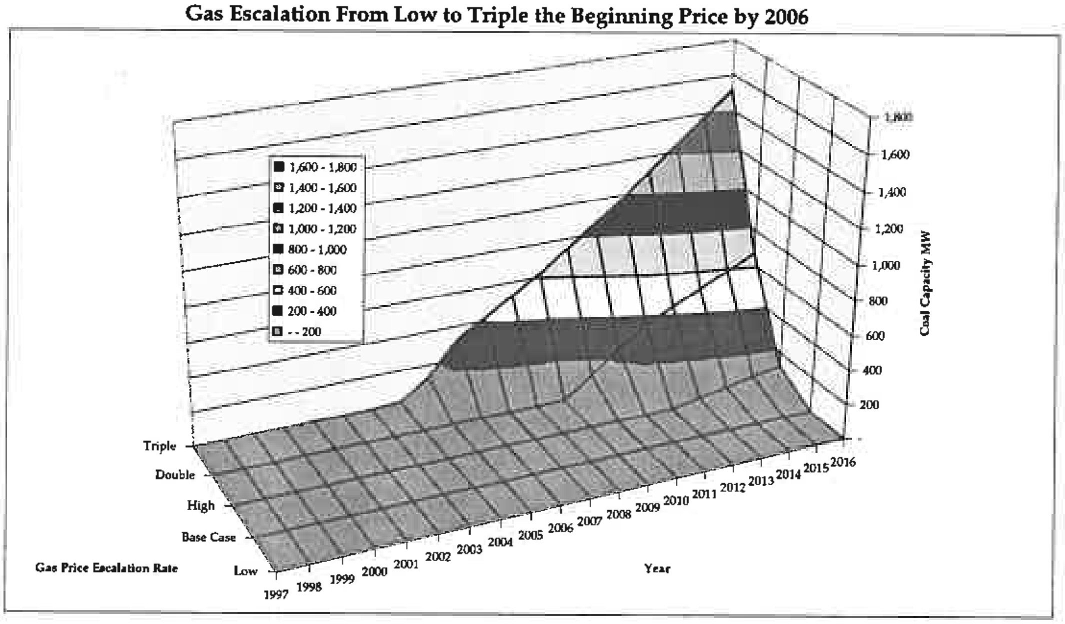
Sweep 5: Sensitivity less Base Case - Resource Selections by 2006, Emissions, and Financial Results
Gas Escalation From Low to Triple the Beginning Price by 2006

	Low Escalation	Base Case	High Escalation	Double by 2006	Triple by 2006
Case #	**31**	**1**	**32**	**33**	**34**
Summer Peak Capacity in Year 2006 (MW)					
1 Native Load	-	-	-	-	-
2 Long Term Sales	-	-	-	-	-
3 less DSM	14	-	(14)	(27)	(33)
4 **Total Requirements**	14	-	(14)	(27)	(33)
5 Existing Generation	-	-	-	(35)	(211)
6 Long Term Purchase	-	-	-	-	-
7 New Resources	-	-	-	-	-
8 Renewable	-	-	-	-	-
9 Cogeneration	137	-	(87)	(215)	(423)
10 Combined Cycle CT	-	-	-	-	-
11 Coal	-	-	-	-	317
12 Transmission	-	-	-	35	209
13 Peaking Resources	(121)	-	71	186	72
14 **Total Resources**	15	-	(16)	(30)	(37)
15 Reserves	2	-	(1)	(3)	(3)
16 Reserve Margin (RM) (%)	-	-	-	-	-
Annual Energy in Year 2006 (MWa)					
17 Native Load	-	-	-	-	-
18 Pump Storage/Peak Return	-	-	-	-	-
19 Long Term Sales	-	-	-	-	-
20 Short Term Sales	(22)	-	(28)	(9)	145
21 less DSM	12	-	(12)	(24)	(30)
22 **Total Requirements**	(10)	-	(40)	(33)	115
23 Existing Generation	(205)	-	81	197	138
24 Long Term Purchases	-	-	-	-	-
25 Short Term Purchases	1	-	(48)	(80)	(142)
26 New Resources					
27 Renewable	-	-	-	-	-
28 Cogeneration	194	-	(74)	(182)	(359)
29 Combined Cycle CT	-	-	-	-	-
30 Coal	-	-	-	-	288
31 Transmission	-	-	-	32	190
32 Peaking Resources	-	-	-	-	-
33 **Total Resources**	(10)	-	(40)	(33)	115
Average Annual Emission in 1997-2046 (1000 tons)					
34 CO_2	(647)	-	479	1,626	3,637
35 NO_x	(2.3)	-	1.5	3.8	6.3
Financial Results with End Effects to 2046					
36 50-year Utility Cost					
37 NPV at 7.9% (million $)	32	-	(235)	(871)	(2,692)
38 Real Levelized (mills/kWh)	(0.13)	-	(0.15)	(0.69)	(2.32)
39 50-year Total Resources Cost					
40 NPV at 7.9% (million $)	34	-	(249)	(889)	(2,702)
41 Real Levelized (mills/kWh)	0.03	-	(0.22)	(0.78)	(2.38)

Graph 3 - 29
Sweep 5: Cogeneration Resources Selected
Gas Escalation From Low to Triple the Beginning Price by 2006



Graph 3 - 30
Sweep 5: Coal Resources Selected (MW)
Gas Escalation From Low to Triple the Beginning Price by 2006



Sweep 6: Load Change From +625 to -625 MW Over Five Years

The sixth sweep addressed load change. It varied the amount of industrial load change in the OWC load area from a 625 MW load loss over the first five years to a 625 MW load gain over the first five years. This is equivalent to a 500 MWa change in load, assuming an 80 percent capacity factor. A 625 MW load loss or gain would be 14.4 percent of the total load in OWC, and a 6.3 percent change in total system load. Each case added or subtracted an additional one-fifth of the load loss or gain each year for a period of five years beginning in 1999. For example, a 625 MW load gain occurred as 125 MW change in 1999, 250 MWa change in 2000, etc., until the fifth year (2003) witnessed a 625 MW change.

Graph 3-31 shows the impact of the large load losses. The company's reserve margin would increase dramatically because the remaining load would not need all of the company's existing resources.

Graph 3 - 31
Sweep 6: Summer Reserve Margin %
Load Change From +625 MW To -625 MW Over Five Years

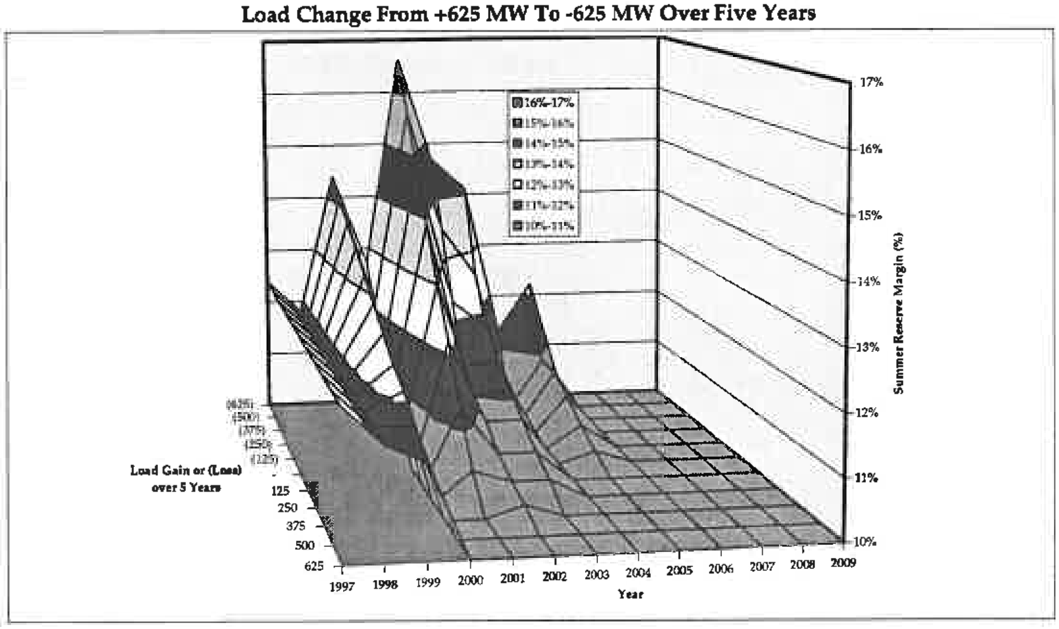


Table 3-32 shows the results after ten years. Table 3-33 shows the differences from each of the sensitivities to the base case. The amount of DSM was not strongly affected by this degree of load change. For a load change of 1,250 MWa (from a 625 MW loss to a 625 MW gain), DSM varied from 249 MWa to 257 MWa, a change of only 8 MWa over a ten year period. As expected, the amount of cogeneration and peaking resources added by the model increased with the amount of total load.

Table 3 - 32
Sweep 6: Resource Selections by 2006, Emissions, and Financial Results
Load Change From +625 to -625 MW Over Five Years

	(625)	(500)	(375)	(250)	(125)	0	125	250	375	500	625
Case #	6-1	6-2	6-3	6-4	6-5	6-6	6-7	6-8	6-9	6-10	6-11
Summer Peak Capacity in Year 2006 (MW)											
1 Native Load	8,319	8,444	8,569	8,694	8,819	8,944	9,069	9,194	9,319	9,444	9,569
2 Long Term Sales	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362
3 less DSM	(249)	(250)	(251)	(252)	(254)	(254)	(256)	(256)	(257)	(257)	(257)
4 **Total Requirements**	9,432	9,556	9,680	9,804	9,927	10,052	10,175	10,300	10,424	10,549	10,674
5 Existing Generation	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653
6 Long Term Purchase	658	658	658	658	658	658	658	658	658	658	658
7 New Resources											
8 Renewable	-	-	-	-	-	-	-	-	-	-	-
9 Cogeneration	65	193	302	412	518	625	728	838	952	1,064	1,220
10 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-
11 Coal	-	-	-	-	-	-	-	-	-	-	-
12 Transmission	-	-	-	-	-	-	-	-	-	-	-
13 Peaking Resources	-	8	35	61	92	121	155	181	204	230	211
14 **Total Resources**	10,375	10,512	10,648	10,784	10,920	11,058	11,193	11,330	11,467	11,604	11,742
15 Reserves	943	956	968	980	993	1,005	1,017	1,030	1,042	1,055	1,067
16 Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Annual Energy In Year 2006 (MWa)											
17 Native Load	6,098	6,198	6,298	6,398	6,498	6,598	6,698	6,798	6,898	6,998	7,098
18 Pump Storage/Peak Return	257	257	257	257	257	257	257	257	257	257	257
19 Long Term Sales	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086
20 Short Term Sales	1,297	1,307	1,303	1,300	1,296	1,291	1,284	1,279	1,280	1,276	1,295
21 less DSM	(183)	(183)	(184)	(185)	(186)	(187)	(188)	(189)	(189)	(189)	(189)
22 **Total Requirements**	8,555	8,665	8,760	8,856	8,951	9,045	9,136	9,230	9,331	9,428	9,546
23 Existing Generation	7,675	7,675	7,679	7,681	7,687	7,689	7,693	7,694	7,695	7,695	7,677
24 Long Term Purchases	466	466	466	466	466	466	466	466	466	466	466
25 Short Term Purchases	360	359	358	358	358	358	357	357	359	360	353
26 New Resources											
27 Renewable	-	-	-	-	-	-	-	-	-	-	-
28 Cogeneration	55	165	257	351	441	532	619	713	811	906	1,050
29 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-
30 Coal	-	-	-	-	-	-	-	-	-	-	-
31 Transmission	-	-	-	-	-	-	-	-	-	-	-
32 Peaking Resources	-	-	-	-	-	-	-	-	-	-	-
33 **Total Resources**	8,555	8,665	8,760	8,856	8,951	9,045	9,136	9,230	9,331	9,428	9,546
Average Annual Emission in 1997-2046 (1000 tons)											
34 CO_2	57,971	58,331	58,643	58,949	59,253	59,536	59,830	60,158	60,534	60,932	61,272
35 NO_x	131.2	131.4	131.6	131.7	131.8	131.9	132.0	132.2	132.5	132.8	133.1
Financial Results with End Effects to 2046											
36 50-year Utility Cost											
37 NPV at 7.9% (million $)	44,197	44,506	44,822	45,155	45,489	45,827	46,159	46,489	46,821	47,156	47,500
38 Real Levelized (mills/kWh)	42.93	42.64	42.37	42.13	42.02	41.83	41.56	41.36	41.14	40.93	40.73
39 50-year Total Resources Cost											
40 NPV at 7.9% (million $)	43,650	43,960	44,275	44,608	44,958	45,304	45,612	45,942	46,274	46,609	46,953
41 Real Levelized (mills/kWh)	41.04	40.79	40.55	40.34	40.14	39.95	39.73	39.53	39.34	39.15	38.98

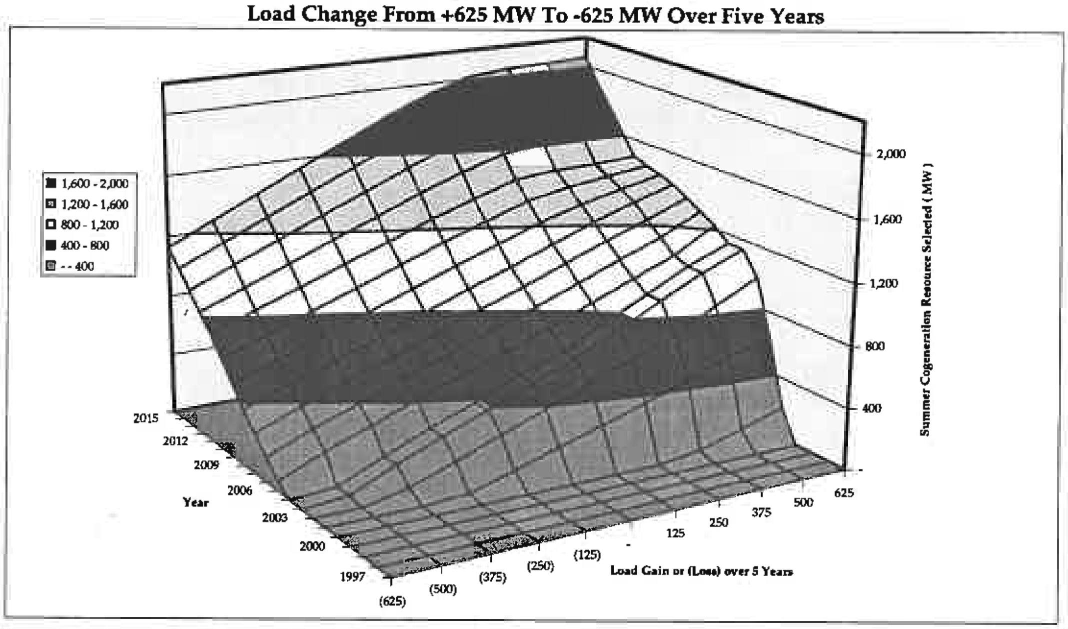
Table 3 - 33

Sweep 6: Sensitivity less Base Case - Resource Selections by 2006, Emissions, and Financial Results
Load Change From +625 to -625 MW Over Five Years

		(625)	(500)	(375)	(250)	(125)	0	125	250	375	500	625
	Case #	6-1	6-2	6-3	6-4	6-5	6-6	6-7	6-8	6-9	6-10	6-11
	Summer Peak Capacity in Year 2006 (MW)											
1	Native Load	(625)	(500)	(375)	(250)	(125)	-	125	250	375	500	625
2	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-
3	less DSM	5	4	3	2	-	-	(2)	(2)	(3)	(3)	(3)
4	**Total Requirements**	(620)	(496)	(372)	(248)	(125)	-	123	248	372	497	622
5	Existing Generation	-	-	-	-	-	-	-	-	-	-	-
6	Long Term Purchase	-	-	-	-	-	-	-	-	-	-	-
7	New Resources	-	-	-	-	-	-	-	-	-	-	-
8	Renewable	-	-	-	-	-	-	-	-	-	-	-
9	Cogeneration	(561)	(432)	(323)	(213)	(108)	-	102	213	327	438	595
10	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-
11	Coal	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-	-	-	-
13	Peaking Resources	(121)	(113)	(86)	(60)	(30)	-	33	59	82	109	90
14	**Total Resources**	(683)	(546)	(410)	(274)	(139)	-	134	271	408	546	684
15	Reserves	(62)	(49)	(37)	(25)	(12)	-	12	25	37	50	62
16	Reserve Margin (RM) (%)	-	-	-	-	-	-	-	-	-	-	-
	Annual Energy in Year 2006 (MWa)											
17	Native Load	(500)	(400)	(300)	(200)	(100)	-	100	200	300	400	500
18	Pump Storage/Peak Return	-	-	-	-	-	-	-	-	-	-	-
19	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-
20	Short Term Sales	6	16	12	9	5	-	(8)	(12)	(12)	(15)	4
21	less DSM	4	4	2	1	0	-	(2)	(3)	(3)	(3)	(3)
22	**Total Requirements**	(490)	(381)	(286)	(190)	(95)	-	91	185	286	382	501
23	Existing Generation	(15)	(14)	(11)	(9)	(3)	-	4	5	6	6	(12)
24	Long Term Purchases	-	-	-	-	-	-	-	-	-	-	-
25	Short Term Purchases	2	1	0	0	(0)	-	(1)	(1)	1	3	(5)
26	New Resources											
27	Renewable	-	-	-	-	-	-	-	-	-	-	-
28	Cogeneration	(477)	(368)	(275)	(181)	(92)	-	87	181	278	374	518
29	Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-
30	Coal	-	-	-	-	-	-	-	-	-	-	-
31	Transmission	-	-	-	-	-	-	-	-	-	-	-
32	Peaking Resources	-	-	-	-	-	-	-	-	-	-	-
33	**Total Resources**	(490)	(381)	(286)	(190)	(95)	-	91	185	286	382	501
	Average Annual Emission in 1997-2046 (1000 tons)											
34	CO_2	(1,565)	(1,205)	(893)	(587)	(283)	-	294	622	998	1,396	1,736
35	NOx	(0.7)	(0.5)	(0.3)	(0.2)	(0.1)	-	0.1	0.3	0.6	0.9	1.2
	Financial Results with End Effects to 2046											
36	50-year Utility Cost											
37	NPV at 7.9% (million $)	(1,631)	(1,321)	(1,005)	(673)	(339)	-	332	661	993	1,328	1,672
38	Real Levelized (mills/kWh)	1.10	0.81	0.54	0.30	0.19	-	(0.27)	(0.47)	(0.69)	(0.90)	(1.10)
39	50-year Total Resources Cost											
40	NPV at 7.9% (million $)	(1,654)	(1,344)	(1,028)	(696)	(346)	-	309	638	970	1,305	1,649
41	Real Levelized (mills/kWh)	1.09	0.84	0.60	0.39	0.19	-	(0.22)	(0.42)	(0.61)	(0.79)	(0.97)

Graph 3-34 shows the amount of cogeneration added. Even in the cases with a load loss, the model added resources. This is due to system growth of approximately 250 MW per year. These cases assumed a maximum loss of 125 MW loss per year, the system was still growing by 125 MW per year. Thus, the total system continued to grow, just not as quickly as in the base case. As expected, total emissions increased with the load gain.

Graph 3 - 34
Sweep 6: Cogeneration Resources Selected
Load Change From +625 MW To -625 MW Over Five Years



Customer prices decreased as the total load increased. This is consistent with findings in both RAMPP-3 and RAMPP-4. With a loss of 625 MW, average customer prices would be 42.93 mills/kWh, which reduced to 40.73 mills/kWh under the assumption of a 625 MW load gain.

Sweep 7: Geographical Load Loss

The seventh sweep explored geographical load variation. Whereas the other sweeps changed only one factor, this sweep looked at a 125 MW load losses in each of the company's four load areas of OWC, Utah, Wyoming, or Idaho (cases 41, 42, 43, and 44), a 625 MW load loss in 1999 in OWC or Utah (cases 46 and 47), and a 625 MW load loss over five years in OWC and Utah. The 125 MW load losses represent 1.65 percent of the company's summer peak load. The 625 MW load losses represent 7.87 percent of the company's load. Table 3-35 shows the results after ten years, and Table 3-36 shows the differences in results from the base case.

Table 3 - 35
Sweep 7: Resource Selections by 2006, Emissions, and Financial Results
Geographical Load Variation Cases

	Base Case Study	125 MW Industrial Customer Load Loss in				625 MW Industrial Load Loss in 1999		625 MW Industrial Load Loss over 5 Years	
Case Name		**OWC**	**Utah**	**Wyo**	**Idaho**	**OWC**	**Utah**	**OWC**	**Utah**
Case #	**1**	**41**	**42**	**43**	**44**	**46**	**47**	**48**	**49**
Summer Peak Capacity in Year 2006 (MW)									
1 Native Load	8,944	8,819	8,819	8,819	8,819	8,319	8,319	8,319	8,319
2 Long Term Sales	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362
3 less DSM	(254)	(254)	(253)	(253)	(254)	(230)	(234)	(235)	(225)
4 **Total Requirements**	**10,052**	**9,927**	**9,928**	**9,928**	**9,927**	**9,451**	**9,447**	**9,446**	**9,456**
5 Existing Generation	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653
6 Long Term Purchase	658	658	658	658	658	658	658	658	658
7 New Resources									
8 Renewable	-	-	-	-	-	-	-	-	-
9 Cogeneration	625	518	551	552	529	85	144	80	157
10 Combined Cycle CT	-	-	-	-	-	-	-	-	-
11 Coal	-	-	-	-	-	-	-	-	-
12 Transmission	-	-	-	-	-	-	-	-	-
13 Peaking Resources	121	92	59	58	80	-	-	-	-
14 **Total Resources**	**11,058**	**10,920**	**10,921**	**10,921**	**10,920**	**10,396**	**10,455**	**10,391**	**10,467**
15 Reserves	1,005	993	993	993	993	945	1,007	945	1,012
16 Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.0	10.0	10.7	10.0	10.7
Annual Energy in Year 2006 (MWa)									
17 Native Load	6,598	6,498	6,498	6,498	6,498	6,098	6,098	6,098	6,098
18 Pump Storage/Peak Return	257	257	257	257	257	257	257	257	257
19 Long Term Sales	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086
20 Short Term Sales	1,291	1,268	1,305	1,277	1,300	1,264	1,274	1,297	1,283
21 less DSM	(187)	(186)	(186)	(186)	(186)	(165)	(170)	(170)	(161)
22 **Total Requirements**	**9,045**	**8,923**	**8,959**	**8,931**	**8,955**	**8,539**	**8,545**	**8,568**	**8,562**
23 Existing Generation	7,689	7,687	7,669	7,663	7,680	7,674	7,629	7,674	7,629
24 Long Term Purchases	466	466	466	466	466	466	466	466	466
25 Short Term Purchases	358	330	355	333	358	327	328	360	334
26 New Resources									
27 Renewable	-	-	-	-	-	-	-	-	-
28 Cogeneration	532	441	469	469	450	72	122	68	133
29 Combined Cycle CT	-	-	-	-	-	-	-	-	-
30 Coal	-	-	-	-	-	-	-	-	-
31 Transmission	-	-	-	-	-	-	-	-	-
32 Peaking Resources	-	-	-	-	-	-	-	-	-
33 **Total Resources**	9,045	8,923	8,959	8,931	8,955	8,539	8,545	8,568	8,562
Average Annual Emission in 1997-2046 (1000 tons)									
34 CO_2	59,536	59,195	59,137	59,115	59,172	57,709	57,465	58,032	57,898
35 NO_x	131.9	131.8	131.6	131.5	131.7	130.7	129.9	131.2	130.7
Financial Results with End Effects to 2046									
36 50-year Utility Cost									
37 NPV at 7.9% (million $)	45,827	45,467	45,459	45,472	45,460	44,171	44,108	44,269	44,256
38 Real Levelized (mills/kWh)	41.83	42.06	42.05	42.06	42.05	43.14	43.15	43.00	42.90
39 50-year Total Resources Cost									
40 NPV at 7.9% (million $)	45,304	44,935	44,927	44,940	44,929	43,605	43,551	43,723	43,689
41 Real Levelized (mills/kWh)	39.95	40.18	40.17	40.18	40.17	41.29	41.24	41.11	41.08
42 **IPM Obj Function (millions $)**	17,970	17,644	17,640	17,671	17,653	16,430	16,402	16,527	16,515

Table 3 - 36

Sweep 7: Sensitivity less Base Case - Resource Selections by 2006, Emissions, and Financial Results

Geographical Load Variations

	Case Name	Base Case Study	125 MW Industrial Customer Load Loss in: OWC	Utah	Wyo	Idaho	625 MW Industrial Load Loss in 1999: OWC	Utah	625 MW Industrial Load Loss over 5 Years: OWC	Utah
	Case #	1	41	42	43	44	46	47	48	49
	Summer Peak Capacity in Year 2006 (MW)									
1	Native Load	-	(125)	(125)	(125)	(125)	(625)	(625)	(625)	(625)
2	Long Term Sales	-	-	-	-	-	-	-	-	-
3	less DSM	-	-	1	1	-	24	20	19	29
4	**Total Requirements**	-	**(125)**	**(124)**	**(124)**	**(125)**	**(601)**	**(605)**	**(606)**	**(596)**
5	Existing Generation	-	-	-	-	-	-	-	-	-
6	Long Term Purchase	-	-	-	-	-	-	-	-	-
7	New Resources	-	-	-	-	-	-	-	-	-
8	Renewable	-	-	-	-	-	-	-	-	-
9	Cogeneration	-	(108)	(75)	(74)	(96)	(541)	(482)	(546)	(469)
10	Combined Cycle CT	-	-	-	-	-	-	-	-	-
11	Coal	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-	-
13	Peaking Resources	-	(30)	(62)	(63)	(41)	(121)	(121)	(121)	(121)
14	**Total Resources**	-	**(139)**	**(137)**	**(137)**	**(138)**	**(662)**	**(603)**	**(667)**	**(591)**
15	Reserves	-	(12)	(12)	(12)	(12)	(60)	2	(60)	7
16	Reserve Margin (RM) (%)	-	-	-	-	-	-	0.7	-	0.7
	Annual Energy in Year 2006 (MWa)									
17	Native Load	-	(100)	(100)	(100)	(100)	(500)	(500)	(500)	(500)
18	Pump Storage/Peak Return	-	-	-	-	-	-	-	-	-
19	Long Term Sales	-	-	-	-	-	-	-	-	-
20	Short Term Sales	-	(23)	13	(15)	9	(27)	(17)	6	(9)
21	less DSM	-	0	0	1	0	21	17	17	25
22	**Total Requirements**	-	**(123)**	**(86)**	**(114)**	**(91)**	**(506)**	**(500)**	**(478)**	**(484)**
23	Existing Generation	-	(3)	(20)	(26)	(9)	(15)	(61)	(15)	(61)
24	Long Term Purchases	-	-	-	-	-	-	-	-	-
25	Short Term Purchases	-	(28)	(3)	(25)	0	(31)	(30)	2	(24)
26	New Resources									
27	Renewable	-	-	-	-	-	-	-	-	-
28	Cogeneration	-	(92)	(64)	(63)	(82)	(460)	(410)	(464)	(399)
29	Combined Cycle CT	-	-	-	-	-	-	-	-	-
30	Coal	-	-	-	-	-	-	-	-	-
31	Transmission	-	-	-	-	-	-	-	-	-
32	Peaking Resources	-	-	-	-	-	-	-	-	-
33	**Total Resources**	-	**(123)**	**(86)**	**(114)**	**(91)**	**(506)**	**(500)**	**(478)**	**(484)**
	Average Annual Emission in 1997-2046 (1000 tons)									
34	CO_2	-	(341)	(399)	(421)	(364)	(1,827)	(2,071)	(1,504)	(1,638)
35	NOx	-	(0.1)	(0.3)	(0.4)	(0.2)	(1.2)	(2.0)	(0.7)	(1.2)
	Financial Results with End Effects to 2046									
36	50-year Utility Cost									
37	NPV at 7.9% (million $)	-	(361)	(368)	(355)	(367)	(1,656)	(1,720)	(1,558)	(1,572)
38	Real Levelized (mills/kWh)	-	0.23	0.22	0.23	0.22	1.31	1.32	1.17	1.07
39	50-year Total Resources Cost									
40	NPV at 7.9% (million $)	-	(369)	(376)	(364)	(374)	(1,699)	(1,752)	(1,581)	(1,615)
41	Real Levelized (mills/kWh)	-	0.23	0.22	0.23	0.22	1.34	1.29	1.16	1.13
42	**IPM Obj Function (millions $)**	-	(326)	(330)	(299)	(317)	(1,541)	(1,568)	(1,443)	(1,455)

If the company were to lose 125 MW of load, it would have virtually no impact on DSM. However, the impact on the amount of cogeneration selected varied slightly by load area. If the loss occurred on the eastern side of the system (in Utah or Wyoming) the model added 551-552 MW of cogeneration, 74-75 MW less than the base case. However, if the load loss occurred on the western side of the system, in OWC or Idaho, the model added only 518-529 MW of cogeneration, 96-108 MW less than the base case. This difference of 22 to 33 MW is probably not significant.

Similarly, peaking resource additions varied by the load area in which the load loss occurred. The model selected slightly more peaking resources if the load loss occurred on the western side of the system.

If the company were to lose 625 MW of load in 1999 in OWC or Utah the impacts would be only slightly different than a loss of 625 MW over five years as in Sweep 6. A sudden load loss of 625 MW would result in the addition of 85 MW of cogeneration in OWC (541 MW less than in the base case) or 144 MW in Utah (481 MW less than in the base case) over ten years. If the loss occurred as a 125 MW loss each year over five years in OWC the model added 65 MW.

The last two cases in this sweep assumed a 625 MW industrial load loss over five years in OWC and in Utah (cases 48 and 49). Case 48 is almost the same as the first sensitivity used in Sweep 6. In Sweep 6 the modeling assumed a constant level of DSM. In Case 48 the model could reduce the amount of DSM. A load loss in Utah would result in about 75 MW more of cogeneration added to the system than if the loss occurred in OWC.

The cases with only a 125 MW load loss showed little difference in customer prices from the base case. With a 625 MW industrial load loss, either suddenly in 1999 or over five years, customer prices would increase slightly, from 41.83 mills/kWh in the base case to around 43 mills/kWh.

Sweep 8: Environmental Adders

Sweep eight varied the level of environmental adders from 0 to $40/ton for CO_2, with a corresponding variation in adders for NOx and TSP. The company believes that there is a low risk of such high adders being imposed. A more likely resolution of current concerns about global climate issues is the use of offsets and a trading system, similar to that adopted for sulfur dioxide emissions. Recent research suggests that there is a significant amount of offsets for CO_2 available at less than $2.00 per ton.

The largest impact of environmental adders was on the reserve margin. As shown in Graph 3-37, the reserve margin reached a high of 24 percent at a CO_2 adder of $10/ton. The two highest adder levels, of $25/ton and $40/ton, are not shown on the graph. In those sensitivities, the reserve margin reached 60 and 63 percent, respectively.

Graph 3 - 37
Sweep 8: Summer Reserve Margin
Environmental Adders From 0 To $40/Ton CO2, NOx & TSP Adders

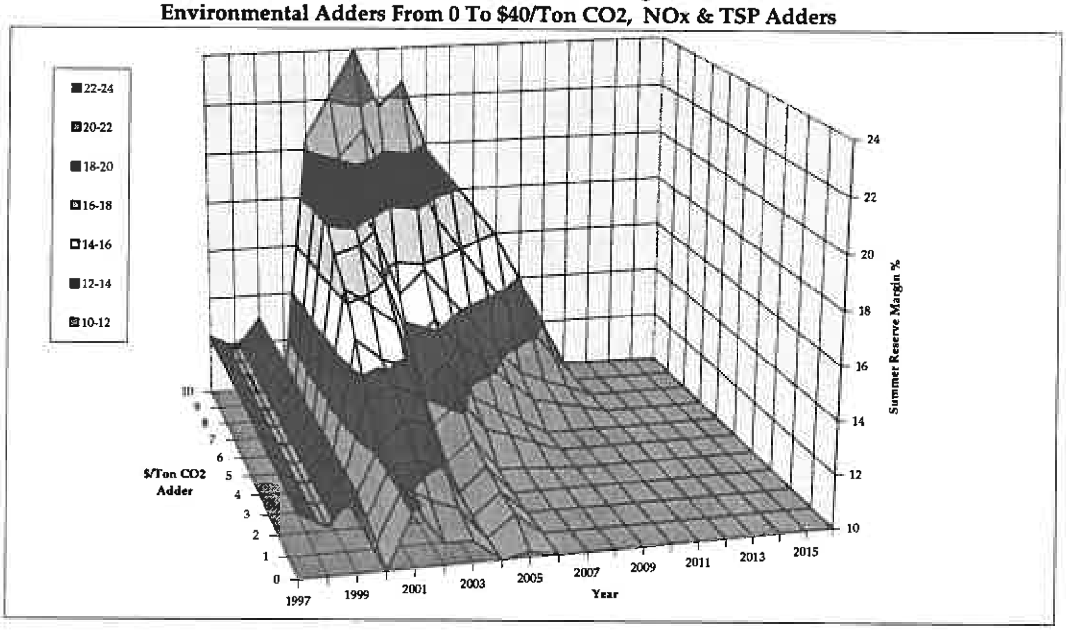


Table 3-38 shows the results after ten years, and Table 3-39 shows the differences in results from the base case. At higher adder amounts, the model reduced operation of the company's coal-fired plants and replaced that power with purchases off the wholesale market, which carry an adder commensurate with gas-fired resources.

The higher the level of adders, the greater the amount of DSM selected by the model, from 254 MW over the first ten years in the base case, to 299 MW in the $40/ton sensitivity. Rather than increase DSM further, a more cost effective choice for the model was to purchase additional power on the wholesale market.

The model selected increasing amounts of gas-fired cogeneration with increasing levels of adders, and replaced the power from existing coal-fired plants with power from the new gas-fired plants, thus contributing to higher reserve margins. Graph 3-40 shows this pattern. At the two highest adder levels, the model ran out of available cogeneration, and added 1,884 MW of combined cycle CTs.

Graph 3-41 shows the CO_2 emissions in millions of tons resulting from each of the sensitivities up to a $10/ton adder level. The choices the model made to accommodate the adders resulted in a steady reduction in emissions as the level of the adder increased.

Table 3 - 38

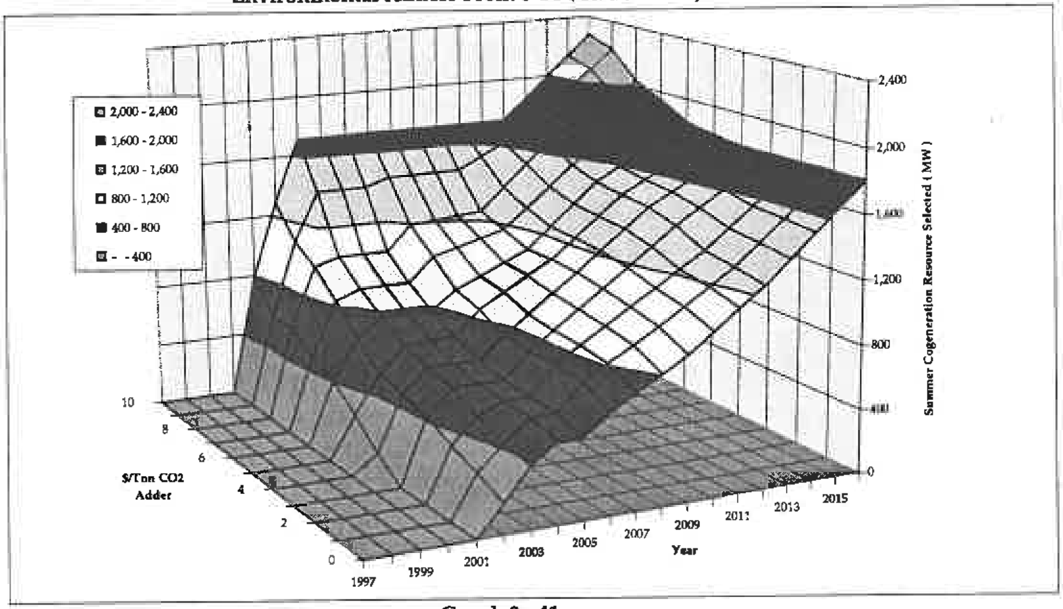
Sweep 8: Resource Selections by 2006, Emissions, and Financial Results
Environmental Adders From 0 To $40/Ton CO2, NOx & TSP Adders

	Base Case	$1 /Ton	$2 /Ton	$3 /Ton	$4 /Ton	$5 /Ton	$6 /Ton	$7 /Ton	$8 /Ton	$9 /Ton	$10 /Ton	$25 /Ton	$40 /Ton
Case #	1	7-1	7-2	7-3	7-4	7-5	7-6	7-7	7-8	7-9	21	22	23
Summer Peak Capacity in Year 2006 (MW)													
1 Native Load	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944	8,944
2 Long Term Sales	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362
3 less DSM	(254)	(255)	(259)	(261)	(263)	(266)	(268)	(270)	(271)	(272)	(274)	(299)	(299)
4 **Total Requirements**	10,052	10,051	10,047	10,045	10,043	10,040	10,038	10,036	10,035	10,034	10,032	10,007	10,007
5 Existing Generation	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653	9,653
6 Long Term Purchase	658	658	658	658	658	658	658	658	658	658	658	658	658
7 New Resources													
8 Renewable	-	-	-	-	-	-	-	-	-	-	-	363	663
9 Cogeneration	625	720	742	739	757	847	900	1,048	1,194	1,458	1,711	3,440	3,440
10 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	1,883	1,884
11 Coal	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
13 Peaking Resources	121	25	-	-	-	-	-	-	-	-	-	-	-
14 **Total Resources**	11,058	11,056	11,052	11,050	11,067	11,158	11,211	11,359	11,505	11,769	12,022	15,997	16,299
15 Reserves	1,005	1,005	1,005	1,004	1,024	1,117	1,172	1,322	1,470	1,735	1,989	5,990	6,291
16 Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.2	11.1	11.7	13.2	14.6	17.3	19.8	59.9	62.9
Annual Energy in Year 2006 (MWa)													
17 Native Load	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598	6,598
18 Pump Storage/Peak Return	257	257	257	257	257	257	257	257	257	257	257	257	257
19 Long Term Sales	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086
20 Short Term Sales	1,291	1,263	1,241	1,238	1,234	1,251	1,259	1,276	1,251	1,266	1,270	885	836
21 less DSM	(187)	(189)	(192)	(194)	(198)	(200)	(202)	(203)	(204)	(205)	(206)	(227)	(227)
22 **Total Requirements**	9,045	9,015	8,990	8,984	8,977	8,992	8,997	9,013	8,987	9,001	9,004	8,599	8,550
23 Existing Generation	7,689	7,561	7,464	7,444	7,405	7,324	7,265	7,139	6,955	6,707	6,441	2,022	1,780
24 Long Term Purchases	466	466	466	466	466	466	466	466	465	465	465	466	466
25 Short Term Purchases	358	375	374	375	379	378	382	377	384	386	405	566	531
26 New Resources													
27 Renewable	-	-	-	-	-	-	-	-	-	-	-	355	640
28 Cogeneration	532	613	686	699	727	824	884	1,031	1,182	1,443	1,693	3,406	3,406
29 Combined Cycle CT	-	-	-	-	-	-	-	-	-	-	-	1,784	1,727
30 Coal	-	-	-	-	-	-	-	-	-	-	-	-	-
31 Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
32 Peaking Resources	-	-	-	-	-	-	-	-	-	-	-	-	-
33 **Total Resources**	9,045	9,015	8,990	8,984	8,977	8,992	8,997	9,013	8,987	9,001	9,004	8,599	8,550
Average Annual Emission in 1997-2046 (1000 tons)													
34 CO2	59,536	59,042	58,382	57,916	57,454	56,984	56,493	55,624	54,859	53,777	52,636	29,118	26,371
35 NOx	131.9	130.3	128.2	126.7	125.3	123.9	122.3	119.4	116.9	113.5	109.8	34.6	27.8
Financial Results with End Effects to 2046													
36 50-year Utility Cost													
37 NPV at 7.9% (million $)	45,827	45,830	45,851	45,892	45,955	46,020	46,107	46,219	46,329	46,492	46,732	57,075	59,157
38 Real Levelized (mills/kWh)	41.83	41.81	41.84	41.89	41.95	42.01	42.16	42.26	42.36	42.51	42.73	52.36	54.27
39 50-year Total Resources Cost													
40 NPV at 7.9% (million $)	45,304	45,303	45,304	45,359	45,422	45,488	45,572	45,674	45,794	45,957	46,186	56,557	58,640
41 Real Levelized (mills/kWh)	39.95	39.95	39.95	40.00	40.05	40.11	40.19	40.28	40.38	40.53	40.73	49.87	51.71

Table 3 - 39
Sweep 8: Sensitivity less Base Case - Resource Selections by 2006, Emissions, and Financial Results
Environmental Adders From 0 To $40/Ton CO2, NOx & TSP Adders

		Base Case	$1 /Ton	$2 /Ton	$3 /Ton	$4 /Ton	$5 /Ton	$6 /Ton	$7 /Ton	$8 /Ton	$9 /Ton	$10 /Ton	$25 /Ton	$40 /Ton
	Case #	1	7-1	7-2	7-3	7-4	7-5	7-6	7-7	7-8	7-9	21	22	23
	Summer Peak Capacity in Year 2006 (MW)													
1	Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
3	less DSM	-	(1)	(5)	(7)	(9)	(12)	(14)	(16)	(17)	(18)	(20)	(45)	(45)
4	**Total Requirements**	-	(1)	(5)	(7)	(9)	(12)	(14)	(16)	(17)	(18)	(20)	(45)	(45)
5	Existing Generation	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Long Term Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
7	New Resources	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Cogeneration	-	-	-	-	-	-	-	-	-	-	-	363	663
10	Combined Cycle CT	-	95	116	114	131	221	274	422	569	833	1,085	2,815	2,815
11	Coal	-	-	-	-	-	-	-	-	-	-	-	1,883	1,884
12	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Peaking Resources	-	(96)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
14	**Total Resources**	-	(2)	(6)	(8)	9	100	153	301	447	711	964	4,939	5,241
15	Reserves	-	-	-	(1)	19	112	167	317	465	730	984	4,985	5,286
16	Reserve Margin (RM) (%)	-	-	-	-	0.2	1.1	1.7	3.2	4.6	7.3	9.8	49.9	52.9
	Annual Energy in Year 2006 (MWa)													
17	Native Load	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Pump Storage/Peak Return	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Long Term Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Short Term Sales	-	(28)	(50)	(53)	(58)	(40)	(33)	(15)	(41)	(26)	(21)	(406)	(455)
21	less DSM	-	(2)	(5)	(8)	(11)	(14)	(16)	(17)	(18)	(19)	(20)	(40)	(40)
22	**Total Requirements**	-	(30)	(56)	(61)	(69)	(53)	(48)	(32)	(58)	(44)	(41)	(446)	(496)
23	Existing Generation	-	(128)	(225)	(246)	(284)	(365)	(424)	(550)	(734)	(982)	(1,248)	(5,667)	(5,909)
24	Long Term Purchases	-	-	-	-	-	-	-	-	(1)	(1)	(1)	-	-
25	Short Term Purchases	-	17	16	18	21	20	24	19	26	28	48	208	173
26	New Resources													
27	Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Cogeneration	-	-	-	-	-	-	-	-	-	-	-	355	640
29	Combined Cycle CT	-	81	154	167	195	292	352	499	650	911	1,161	2,873	2,873
30	Coal	-	-	-	-	-	-	-	-	-	-	-	1,784	1,727
31	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Peaking Resources	-	-	-	-	-	-	-	-	-	-	-	-	-
33	**Total Resources**	-	(30)	(56)	(61)	(69)	(53)	(48)	(32)	(58)	(44)	(41)	(446)	(496)
	Average Annual Emission in 1997-2046 (1000 tons)													
34	CO2	-	(494)	(1,154)	(1,620)	(2,082)	(2,552)	(3,043)	(3,912)	(4,676)	(5,758)	(6,900)	(30,418)	(33,165)
35	NOx	-	(1.6)	(3.7)	(5.2)	(6.6)	(8.0)	(9.6)	(12.5)	(15.0)	(18.4)	(22.1)	(97.4)	(104.1)
	Financial Results with End Effects to 2046													
36	50-year Utility Cost													
37	NPV at 7.9% (million $)	-	2	24	64	127	193	279	392	502	664	904	11,248	13,330
38	Real Levelized (mills/kWh)	-	(0.02)	0.01	0.06	0.12	0.18	0.33	0.43	0.53	0.68	0.90	10.53	12.44
39	50-year Total Resources Cost													
40	NPV at 7.9% (million $)	-	(1)	0	56	118	184	268	370	491	653	883	11,254	13,336
41	Real Levelized (mills/kWh)	-	(0.00)	0.00	0.05	0.10	0.16	0.24	0.33	0.43	0.58	0.78	9.92	11.76

Graph 3 - 40
Sweep 8: Cogeneration and Combined Cycle Resources Selected
Environmental Adders From 0 To $40/Ton CO2, NOx & TSP Adders



Graph 3 - 41
Sweep 8: CO2 Emissions
Environmental Adders From 0 To $40/Ton CO2, NOx & TSP Adders

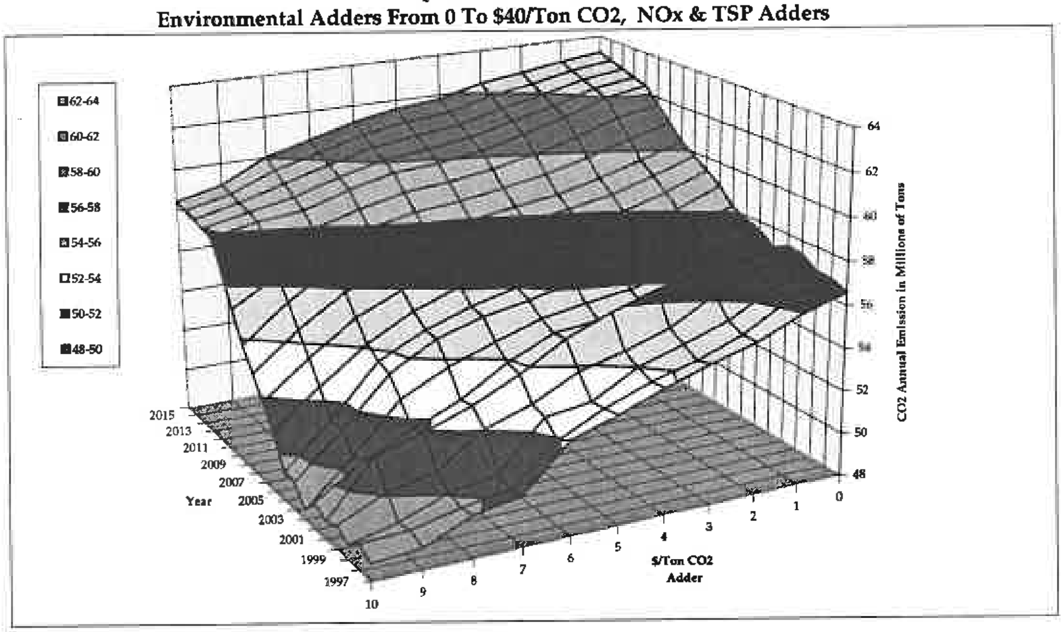


Table 3-42 shows the calculation of the average annual cost and the marginal cost of emission reduction. Graph 3-43 shows the results. The cost per ton to reduce emissions increases dramatically after an adder level of $10/ton. At adder levels of $25/ton and $40/ton, the model's least cost choices resulted in average costs of up to $360 per ton and marginal costs of up to $600/ton. The net present value necessary is $600/ton to avoid payment of $40/ton per year for 50 years.

Table 3 - 42
Sweep 8: Cost of Emission Reduction
Environmental Adders from 0 to $40/Ton, CO2, Nox & TSP Adders

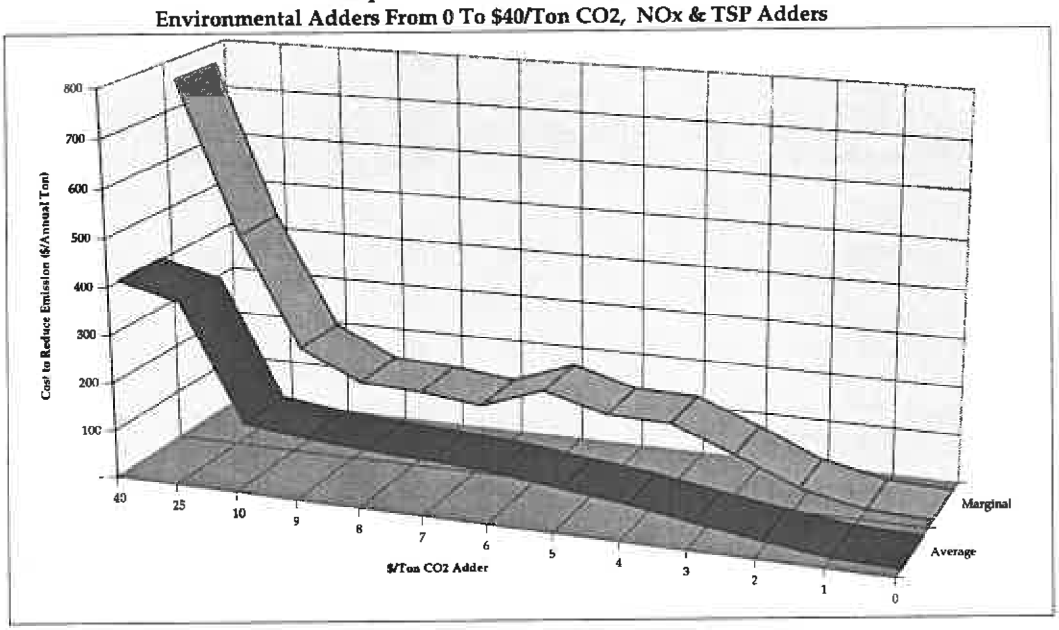
CO2 Tax	Total Change in Emissions (1,000 Tons)			Annual Environmental Tax ($ 1000)				Utility Cost 50-Year NPV ($ Millions)					Average Cost of Emission Reduction 50-Yr NPV per Average Annual Emission ($/ton)		
									Total	Allocated Change					
	CO2	NOx	TSP	CO2	NOx	TSP	Total	Total	Change	CO2	NOx	TSP	CO2	NOx	TSP
1	494	1.6	0.1	59,042	13,031	1,469	73,542	45,830	2.4	1.9	0.4	0.0	4	266	439
2	1,154	3.7	0.2	116,763	25,635	2,909	145,307	45,851	23.8	19.1	4.2	0.5	17	1,125	2,129
3	1,620	5.2	0.3	173,748	38,020	4,317	216,085	45,892	64.3	51.7	11.3	1.3	32	2,184	3,697
4	2,082	6.6	0.5	229,817	50,139	5,689	285,645	45,955	127.2	102.3	22.3	2.5	49	3,402	5,259
5	2,552	8.0	0.6	284,921	61,934	7,043	353,898	46,020	193.0	155.3	33.8	3.8	61	4,198	6,497
6	3,043	9.6	0.7	338,956	73,371	8,363	420,689	46,107	279.1	224.9	48.7	5.5	74	5,056	7,826
7	3,912	12.5	0.9	389,368	83,608	9,564	482,539	46,219	391.8	316.1	67.9	7.8	81	5,443	8,349
8	4,676	15.0	1.1	438,875	93,547	10,735	543,158	46,329	501.7	405.4	86.4	9.9	87	5,769	8,818
9	5,758	18.4	1.4	483,997	102,133	11,764	597,894	46,492	664.5	537.9	113.5	13.1	93	6,159	9,316
10	6,900	22.1	1.7	526,359	109,769	12,676	648,804	46,732	904.2	733.5	153.0	17.7	106	6,909	10,279
25	30,418	97.4	8.8	727,947	86,378	9,541	823,866	57,075	11,247.6	9,938.1	1,179.3	130.3	327	12,112	14,790
40	33,165	104.1	9.3	1,054,824	111,148	12,877	1,178,849	59,157	13,329.9	11,927.5	1,256.8	145.6	360	12,070	15,682

CO2 Tax	Marginal Change in Emissions (1,000 Tons)			Marginal Savings in Environmental Tax Due to Reducted Emission ($1,000)				Utility Cost 50-Year NPV ($ Millions)					Average Cost of Emission Reduction 50-Yr NPV per Average Annual Emission ($/ton)		
									Marginal	Allocated Change					
	CO2	NOx	TSP	CO2	NOx	TSP	Total	Total	Change	CO2	NOx	TSP	CO2	NOx	TSP
1	494	1.6	0.1	494	160	14	668	45,830	2.4	1.8	0.6	0.0	4	359	449
2	660	2.1	0.1	660	213	14	888	45,851	21.4	15.9	5.1	0.3	24	2,412	3,015
3	466	1.4	0.1	466	144	15	625	45,892	40.5	30.1	9.3	1.0	65	6,470	8,087
4	462	1.4	0.1	462	139	17	617	45,955	62.9	47.1	14.1	1.7	102	10,199	12,748
5	470	1.5	0.1	470	148	14	632	46,020	65.8	48.9	15.4	1.4	104	10,410	13,013
6	492	1.6	0.1	492	158	15	665	46,107	86.1	63.7	20.5	1.9	130	12,956	16,195
7	869	2.8	0.2	869	284	28	1,181	46,219	112.7	82.9	27.1	2.6	95	9,544	11,930
8	765	2.5	0.2	765	251	24	1,039	46,329	109.9	80.8	26.5	2.6	106	10,573	13,217
9	1,082	3.5	0.3	1,082	345	35	1,462	46,492	162.8	120.5	38.4	3.9	111	11,134	13,917
10	1,142	3.7	0.3	1,142	371	39	1,552	46,732	239.7	176.3	57.3	6.1	154	15,444	19,305
25	23,518	75.2	7.1	352,770	112,826	13,290	478,886	57,075	10,343.4	7,619.4	2,436.9	287.1	324	32,398	40,498
40	2,747	6.8	0.5	41,209	10,146	896	52,251	59,157	2,082.3	1,642.2	404.4	35.7	598	59,777	74,721

Note: NOx tax is $100/Ton for each $1/Ton of CO2 Tax (If CO2 tax is $5/Ton then NOx Tax is $500 / Ton).
TSP tax is $125/Ton for each $1/Ton of CO2 Tax (If CO2 tax is $5/Ton then TSP Tax is $625 / Ton).

Customer prices increase dramatically as the model uses higher environmental adders. Graph 3-43 shows the cost of environmental adders and the associated price impact on customers. The price impact includes the cost to reconfigure the system to minimize the "tax" from the environmental adder; it does not include payment of the "tax."

Graph 3 - 43
Sweep 8: Cost to Reduce Emissions
Environmental Adders From 0 To $40/Ton CO2, NOx & TSP Adders



However, the company regards these cases as low risk. The company does not believe that high adders being imposed is a very viable scenario. A more likely outcome is some type of offset programs and trading emission program. These offer much cheaper alternatives. Recent research, for example, indicates that a large amount of offsets are available at $2.00 per ton of CO_2.

Other Cases

Tables 3-44 and 3-45 show the last group of seven cases. These covered a variety of issues, including the RAMPP-4 base case, DSM, Utah load growth, solar, gas availability, wholesale market prices and hydro utilization.

Compared to the RAMPP-4 Update base case, results for the RAMPP-4 base case included less long-term purchases, slightly more long-term sales, a larger existing system, more DSM, less gas-fired resource selections, and less peaking resource selections. Emissions in the RAMPP-4 base case were lower, while customer prices were higher.

Table 3 - 44
Other Cases
Resource Selections by 2006, Emissions and Financial Results

#	Case Name	Base Case Study	R4 Base Case	Solar Price Curve	Lower Gas Utilization	Ut 4% Load Growth	Wholesale Price 1997	Reduced Hydro Utilization
	Case #	1	N/A	24	38	45	51	71
	Summer Peak Capacity in Year 2006 (MW)							
1	Native Load	8,944	8,807	8,944	8,944	9,304	8,944	8,944
2	Long Term Sales	1,362	1,485	1,362	1,362	1,362	1,362	1,362
3	less DSM	(254)	(436)	(252)	(257)	(258)	(255)	(252)
4	**Total Requirements**	**10,052**	**9,856**	**10,054**	**10,049**	**10,408**	**10,051**	**10,054**
5	Existing Generation	9,653	10,122	9,653	9,653	9,653	9,653	9,653
6	Long Term Purchase	658	424	658	658	658	658	658
7	New Resources							
8	Renewable	-	-	-	-	-	-	-
9	Cogeneration	625	382	626	660	856	246	752
10	Combined Cycle CT	-	110	-	-	-	-	-
11	Coal	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-
13	Peaking Resources	121	-	123	84	282	500	-
14	**Total Resources**	**11,058**	**11,038**	**11,059**	**11,054**	**11,449**	**11,057**	**11,063**
15	Reserves	1,005	1,182	1,005	1,005	1,041	1,005	1,008
16	Reserve Margin (RM) (%)	10.0	12.0	10.0	10.0	10.0	10.0	10.0
	Annual Energy in Year 2006 (MWa)							
17	Native Load	6,598	6,463	6,598	6,598	6,843	6,598	6,598
18	Pump Storage/Peak Return	257	305	257	257	257	257	257
19	Long Term Sales	1,086	1,266	1,086	1,086	1,086	1,086	1,086
20	Short Term Sales	1,291	889	1,291	1,236	1,272	981	1,247
21	less DSM	(187)	(291)	(186)	(190)	(190)	(185)	(186)
22	**Total Requirements**	**9,045**	**8,631**	**9,046**	**8,987**	**9,268**	**8,736**	**9,001**
23	Existing Generation	7,689	7,746	7,689	7,801	7,706	7,748	7,543
24	Long Term Purchases	466	400	466	466	466	463	466
25	Short Term Purchases	358	15	358	364	367	305	353
26	New Resources							
27	Renewable	-	-	-	-	-	-	-
28	Cogeneration	532	378	532	355	729	220	640
29	Combined Cycle CT	-	92	-	-	-	-	-
30	Coal	-	-	-	-	-	-	-
31	Transmission	-	-	-	-	-	-	-
32	Peaking Resources	-	-	-	-	-	-	-
33	**Total Resources**	**9,045**	**8,631**	**9,046**	**8,987**	**9,268**	**8,736**	**9,001**
	Average Annual Emission in 1997-2046 (1000 tons)							
34	CO_2	59,536	55,118	59,574	60,307	60,770	60,134	60,126
35	NO_x	131.9	125.4	132.2	134.3	132.3	133.6	132.2
	Financial Results with End Effects to 2046							
36	50-year Utility Cost							
37	NPV at 7.9% (million $)	45,827	42,571	46,665	45,866	47,928	47,528	46,251
38	Real Levelized (mills/kWh)	41.83	42.96	42.56	41.85	40.28	43.34	42.22
39	50-year Total Resources Cost							
40	NPV at 7.9% (million $)	45,304	43,225	46,118	45,319	47,401	46,996	45,727
41	Real Levelized (mills/kWh)	39.95	41.29	40.67	39.96	38.61	41.44	40.32
42	**IPM Obj Function (millions $)**	17,970		17,931	18,034	20,026	19,454	18,451

Table 3 - 45

Other Cases

Sensitivity less Base Case - Resource Selections by 2006, Emissions and Financial Results

Case Name	Base Case Study	R4 Base Case	Solar Price Curve	Lower Gas Utilization	Ut 4% Load Growth	Wholesale Price 1997	Reduced Hydro Utilization
Case #	1	N/A	24	38	45	51	71
Summer Peak Capacity in Year 2006 (MW)							
1 Native Load	-	(137)	-	-	360	-	-
2 Long Term Sales	-	123	-	-	-	-	-
3 less DSM	-	(182)	2	(3)	(4)	(1)	2
4 **Total Requirements**	-	**(196)**	**2**	**(3)**	**356**	**(1)**	**2**
5 Existing Generation	-	469	-	-	-	-	-
6 Long Term Purchase	-	(234)	-	-	-	-	-
7 New Resources	-	-	-	-	-	-	-
8 Renewable	-	-	-	-	-	-	-
9 Cogeneration	-	(244)	0	34	231	(380)	126
10 Combined Cycle CT	-	110	-	-	-	-	-
11 Coal	-	-	-	-	-	-	-
12 Transmission	-	-	-	-	-	-	-
13 Peaking Resources	-	(121)	1	(38)	161	379	(121)
14 **Total Resources**	-	**(20)**	**0**	**(5)**	**391**	**(1)**	**5**
15 Reserves	-	177	-	-	36	-	3
16 Reserve Margin (RM) (%)	-	2.0	-	-	-	-	-
Annual Energy in Year 2006 (MWa)							
17 Native Load	-	(136)	-	-	245	-	-
18 Pump Storage/Peak Return	-	48	-	-	-	-	-
19 Long Term Sales	-	180	-	-	-	-	-
20 Short Term Sales	-	(403)	-	(55)	(20)	(310)	(45)
21 less DSM	-	(104)	0	(3)	(3)	1	1
22 **Total Requirements**	-	**(414)**	**0**	**(59)**	**222**	**(309)**	**(44)**
23 Existing Generation	-	57	0	112	16	59	(146)
24 Long Term Purchases	-	(66)	-	-	-	(3)	-
25 Short Term Purchases	-	(343)	-	7	9	(53)	(5)
26 New Resources							
27 Renewable	-	-	-	-	-	-	-
28 Cogeneration	-	(154)	0	(177)	196	(312)	107
29 Combined Cycle CT	-	92	-	-	-	-	-
30 Coal	-	-	-	-	-	-	-
31 Transmission	-	-	-	-	-	-	-
32 Peaking Resources	-	-	-	-	-	-	-
33 **Total Resources**	-	**(414)**	**0**	**(59)**	**222**	**(309)**	**(44)**
Average Annual Emission in 1997-2046 (1000 tons)							
34 CO_2	-	(4,418)	38	771	1,234	598	590
35 NOx	-	(6.5)	0.3	2.4	0.3	1.7	0.3
Financial Results with End Effects to 2046							
36 50-year Utility Cost							
37 NPV at 7.9% (million $)	-	(3,256)	838	39	2,101	1,700	424
38 Real Levelized (mills/kWh)	-	1.13	0.73	0.02	(1.55)	1.51	0.39
39 50-year Total Resources Cost							
40 NPV at 7.9% (million $)	-	(2,078)	814	15	2,097	1,692	424
41 Real Levelized (mills/kWh)	-	1.34	0.72	0.01	(1.34)	1.49	0.37
42 **IPM Obj Function (millions $)**	-		(39)	64	2,056	1,484	481

The no DSM case (case #24) was a repeat of a case included in RAMPP-4. It resulted in an increase in cogeneration and peaking resources selected, and a slight decrease in customer costs.

The company lowered the total resource cost for solar resources in the RAMPP-4 Update base case by 5 percent per year. This resulted in lowering the price of solar resources by 37 percent in real terms by the year 2006. The logic was that solar is on the front end of a learning curve and these price reductions are a reasonable expectation. Thus, all of the other sensitivities included the assumption of decreasing costs for new solar resources. For the solar price curve case #24, the company lowered the total resource cost by another 5 percent per year. This reduced the total resource cost for solar resources by 61 percent in real terms by the year 2006. The result was model selection of solar resources in 2016, at the end of the 20 year study period. However, during the first ten years, the lower price level had no impact on model selections. Adding solar resources during the second ten years resulted in a small price increase for customers.

The lower gas utilization case (case #38) assumed that gas resources were less reliable than assumed in the base case. In the lower gas utilization case gas-fired resources could only be utilized 70 percent of the time, versus 95 percent in the base case. This change in assumptions caused the model to utilize the existing system more, (by 112 MW), increase DSM by 3 MWa, increase the amount of cogeneration capacity selected by the model by 34 MW, and decrease the cogeneration energy output by 177 MWa. Short-term market sales decreased by 55 MW, while short-term market purchases increased by only 7 MW. In spite of these changes in resource selections, the financial impacts are very small.

The Utah load case (case #45) assumed load in Utah would grow at a 4 percent annual rate over the 20 year planning horizon. By the end of ten years the 4 percent growth rate resulted in 360 MW more total system load than in the base case. The impact on DSM was minimal. However, the model selected about 230 MW more cogeneration, and 160 MW more peaking resources to meet the added load. This added load increased emissions slightly, but decreased customer prices.

The wholesale price case (case #51) assumed that short-term wholesale prices would be flat for the entire 20 year planning horizon. This change in assumptions caused the model to decrease the amount of cogeneration capacity selected by 380 MW, and to increase the peaking resources selected by 379 MW. It appears that without a healthy wholesale market to sell excess capacity into, a baseload resource is not as cost effective as a peaking resource. The existing system increased by 59 MWa. Short-term market sales decreased by 310 MWa, while short-term market purchases increased by only 53 MWa. The financial results were significantly affected, with customer prices increasing by 3.6 percent. This reflected the loss of wholesale revenues that would normally be passed on to customers.

The reduced hydro utilization case (case #71) assumed that the capacity factor for the company's hydro system was 25 percent lower than the company expects it to be. The model replaced this power with 126 MW of additional cogeneration capacity. Short-term wholesale market sales decreased by 45 MW, while short-term wholesale market purchases increased by only 5 MW. The average utility cost increased slightly, from 41.83 mills/kWh to 42.22 mills/kWh.

Lessons Learned from the Sensitivities

Existing System

The largest impact on the existing system came from the environmental adder cases. The environmental adders caused the model to use less of the existing system, resulting in high reserve margins. At the highest adder levels the reserve margins reached 63 percent. The model replaced energy from the existing system with purchases off the wholesale market. This is consistent with results from RAMPP-3 and RAMPP-4. The reserve margin also increased under an assumption of major load losses, when the amount of regulated load remaining after the load loss would not require all of the existing system. The company would try to sell any excess energy from those plants, helping to keep total costs low, but on a capacity basis, the reserve margin would remain high.

The model also reduced use of gas-fired resources in the existing system from a 1998 gas price jump of 70 percent or more, or from a 2003 gas price jump of 90 percent or more. Results from Sweep 5 (gas price increases) confirmed this pattern. However, without a wholesale market price linkage to the gas price increases, the model did not reduce operation of the company's existing resources.

DSM

Although the company introduced significant variation in input assumptions, the amount of DSM selected by the model for the first ten years showed little variation. From a base case amount of 254 MW, the lowest level (230 MW, for an 18 percent decrease) occurred in the sensitivity with a 500 MW industrial load loss in OWC in 1999, and the highest level (299 MW, for an 18 percent increase) occurred in the sensitivity with the highest adder level ($40/ton CO_2). None of the cases or sensitivities that altered the gas price assumptions caused more than an 18 percent change in DSM, although some sensitivities changed the gas price level by as much as 200 percent. Although higher amounts of DSM were cost effective under circumstances of higher gas prices, the amount of increase was moderate. A gas/market price jump in 1998 caused more DSM than if the price jump occurred in 2003. Sweep 4 showed that the degree of gas/market linkage seemed to have no impact on DSM levels.

Gas Prices

The extensive analysis of gas price risks revealed that the amount of gas price change required for the model to switch from selecting new gas-fired to selecting new coal-fired resources was a 90 percent increase, which translates to a gas price of $2.80/MMBtu in 1998. The amount of gas price change required for shutting down the company's existing gas-fired plants was a 110 percent increase, which translates to a gas price of $3.06/MMBtu in 1998. The financial results revealed that there is little risk to customers from a gas price jump as long as there is a wholesale market linkage between gas and wholesale electricity prices.

Gas and Market Price Linkage

A 40 percent linkage between gas prices and wholesale market prices is a reasonable assumption. It also is logical, given that the swing resource for most utilities can be coal or gas, so the market response to higher gas prices does not occur in a one-to-one relationship. At a 40 percent linkage, the model's level of short-term wholesale sales and purchases stayed relatively in balance. At a lower linkage, gas prices increased at a faster rate than wholesale market prices. New gas-fired resources became increasingly expensive while the wholesale market price remained low. This resulted in excessive short-term purchases but no offsetting wholesale market for short-term sales. At a higher linkage, new gas-fired resources became increasingly expensive while the wholesale market price also became increasingly high; thereby resulting in excessive short-term sales but no offsetting short-term purchases because of the high cost of purchased power.

Cogeneration

Consistent with results from RAMPP-4 and the RAMPP-4 Update, the model selected cogeneration as the least cost supply-side resource. The range of cogeneration added by the model in the sensitivities was considerably larger than the range of DSM. In the base case the model added 625 MW of cogeneration by the tenth year. A few cases resulted in no cogeneration being added (200 percent gas price jump in 1998 with 40 percent market linkage, and 110 percent or higher gas price jump in 2003 with no market linkage). The maximum in gas-fired resources added by the model was 3,440 MW of cogeneration and an additional 1,884 MW of combined cycle CT assuming the maximum level of environmental adders.

The higher the gas/market price jump, the less gas-fired cogeneration the model added. At a price jump of 200 percent, it added no cogeneration. A gas/market price jump in 1998 caused less selection of cogeneration than if the price jump occurred in 2003. A price jump in 1998 gave the model more time to adjust resource addition choices to the higher gas prices. Without a wholesale market price linkage, the model decreased the cogeneration additions more quickly. This is because baseload plant additions become less cost effective if there is not a good wholesale market in which to sell any excess energy. The amount of cogeneration added by the model increased with the amount of total load. Even in the cases with load loss the model added resources. This is because the total system is growing by more than the amount of load loss assumed per year. The model selected increasing amounts of gas-fired cogeneration with increasing levels of adders. At the two highest adder levels, the model ran out of available cogeneration, and added 1,884 MW of combined cycle CTs.

Coal

At 1998 gas price jumps of 110 percent or more, and at 2003 gas price jumps of 130 percent or more, the model built new coal-fired plants. A gas/market price jump in 1998 caused more selection of coal than if the price jump occurred in 2003 because a price jump in 1998 allowed the model more time to adjust its resource selections to the higher gas prices.

Transmission

The model also used the transmission option beginning at 1998 gas price jumps of 70 percent or more and at 2003 gas price jumps of 90 percent or more. This is a capability of the model to "move" power plants for a cost comparable to wheeling at current prices. A gas/market price jump in 1998 causes more use of the transmission option than if the price jump occurs in 2003. The model typically added coal-fired resources as gas prices increased, but required the transmission option to move the additional energy to energy markets on the West side.

Peaking

As gas/market prices increased the model built more peaking resources, but at the highest price jumps abandoned them in favor of coal-fired plants. The greater the linkage between gas and wholesale market prices, the less peaking resources the model selected. This is because as wholesale market prices increased profit margins for excess energy also increased. Thus, the more cost effective baseload plants became compared to peaking plants.

Emissions

Average emissions did not significantly vary until gas prices reached a point high enough for the model to build more coal-fired plants. Significant load gain also caused emissions to increase. Emissions decreased with environmental adders. The choices the model made to accommodate the adders resulted in a steady reduction in emissions as the level of the adder increased.

Customer Prices

The largest influence on customer prices was environmental adders. In the base case the real levelized 50-year utility cost, which is the best indicator available of customer prices, was 41.83 mills/kWh. The lowest value (37.89 mills/kWh, or a 9 percent decrease) occurred in the sensitivity assuming a 200 percent gas price jump in 1998 and a 40 percent market linkage, and the highest value (54.27 mills/kWh, or a 30 percent increase) occurred in the highest environmental adder case.

As long as there is a reasonable linkage between gas and wholesale market prices, a gas price jump would not hurt customer prices. With the linkage, wholesale market prices kept pace with gas price increases, and the higher prices in the wholesale market allowed the model to gain sufficient revenue from wholesale sales to offset any cost increases in operating existing and new gas-fired plants. A gas price jump without any commensurate wholesale market price increase would increase customer prices slightly. The financial results showed a definite benefit to customers from a greater linkage between gas and wholesale market prices.

Customer prices decreased as the total load increased. This is consistent with findings in both RAMPP-3 and RAMPP-4.

These are valuable lessons from the sensitivities. They are consistent with and confirm the lessons learned in prior RAMPP cycles, especially RAMPP-3 and RAMPP-4. The model chooses resources based on their relative cost effectiveness. Higher gas prices lead to less gas-fired resource selections and more coal-fired resource selections. However, gas prices would have to at least double for coal-fired resources to be cost effective.

Conclusions from RAMPP-3 and RAMPP-4 that are Still Valid

A Need for Fewer Resources

RAMPP-4 showed a need for fewer new resources than RAMPP-3. RAMPP-5 shows a need for fewer new resources than RAMPP-4.

Gas-fired as the Least Cost Supply-Side Resource

In RAMPP-3 coal-fired resources was the least cost supply-side choice. That switched in RAMPP-4 to gas-fired, and has remained in RAMPP-5. The model's selection of gas-fired resources was relatively robust. In both RAMPP-3 and RAMPP-4, changing the gas price escalation rate did not dramatically change the type of 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.

Higher Gas Price Escalation Need not Cause Higher Customer Prices

In all three planning cycles, gas price escalation had little impact on customer prices. This is primarily because of the correlation between gas price escalation and short-term wholesale market prices. A higher gas price escalation leads to higher wholesale market prices, which allows the company to generate more revenue selling excess energy on the short-term wholesale market. These revenues help reduce customer prices.

Higher Load Growth Need not Cause Higher Prices

RAMPP-3 and RAMPP-4 showed that higher or lower load growth caused the model to select the same type of resources, the resource selections just occurred sooner or later. All three planning cycles showed the same pattern of lower customer prices with higher levels of load growth, and higher customer prices with lower levels of load growth. Higher load growth results in more efficient use of the existing system, and the cost of new resources is very close to the average embedded cost of existing resources.

Short-Term Market Prices are Important for Customer Prices

Because of the company's success in using the short-term wholesale markets to buy and sell power, and using the revenues to reduce customer prices, short-term wholesale market prices continue to be important for customer prices. In all three planning cycles, the model made more short-term sales than purchases. These results reinforce a conclusion from RAMPP-4, that the IRP process must use a model that can recognize and use the short-term wholesale market as the company does for daily operations. The IPM model does a reasonably good job of mimicking the company's operations.

Added Transmission is not Cost Effective

The IPM model has an option to "move" a plant from one location to another, using the cost of wheeling over an existing line. In all three planning cycles, the model did not find this option to be a cost effective choice, unless gas prices were at a very high level. RAMPP-5 identified that level to be $2.54/MMBtu.

Renewables are not Cost Effective

All three planning cycles found that renewable resources were not cost effective unless environmental adders were at their highest levels. The loss of the 1.5 cent per kWh tax credit beginning in 1999 will make renewables even less cost effective.

Environmental Adders Add Significantly to Customer Prices

All three planning cycles found that the least cost choices under the assumption of environmental adders greatly increased customer prices. In the RAMPP-5 sensitivity analyses, at the highest adder level, customer prices would increase by 30 percent over the base case level.

Comparison to RAMPP-4 Risk Analysis

The RAMPP-4 report noted that the electric utility industry is becoming a riskier environment in which to do business. That is even more accurate today. 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. Who bears a particular risk is probably less important than that there is risk/reward symmetry. Whichever party takes on the risks of a particular strategy should benefit from the rewards when that strategy works and assume the loss when the strategy doesn't work.

PacifiCorp continues to believe 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 wholesale market prices are competitive, and using the short-term wholesale market when it can gain revenues to reduce prices for customers. The following are some of the components of risk that the company tries to carefully manage.

Relying on the Wholesale Market

Like many other utilities, PacifiCorp plans to rely on the wholesale market to meet any short-term capacity or energy needs for the next several years. The company also plans to increasingly rely on the wholesale market to provide resources needed for long-term wholesale sale contracts. The number of players in the wholesale market has increased dramatically since RAMPP-4, and the amount and price competitiveness of the short-term wholesale market has also increased since RAMPP-4. As long as the wholesale market price remains competitive, the company plans to continue using it as a cost effective method to meet short-term customer needs, and to meet long-term wholesale sale commitments.

As the existing surplus in the western system begins to show signs of exhaustion, as evidenced by higher wholesale prices, the company may need to make longer-term contract arrangements. The RAMPP-5 action plan includes an item to watch the market to be alert to opportunities.

Short-Term Market Prices

Short-term wholesale market price uncertainty presents a risk to retail customer prices. Unfortunately, this is a risk over which the company has no control. However, the company monitors the wholesale market continuously through its active daily involvement, and can thereby follow trends as they occur. This gives PacifiCorp an advantage over utilities which are less active in the wholesale market.

Gas Price Increases

In both RAMPP-3 and RAMPP-4, changes in gas prices had little impact on retail customer prices, other than a positive impact through their linkage with wholesale market prices. RAMPP-5 confirmed this finding. 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 successfully sell power in the wholesale market reduces the retail customer price risk from higher gas prices.

Additional Transmission Investments

The RAMPP-4 analyses indicated that additional transmission investment at this time would not reduce total costs for the system. The RAMPP-5 analyses gives no indication that this conclusion has changed. Given the FERC's role in reducing wholesale market power from a utility's use of their transmission lines, means that the company will have little opportunity to make profitable use of additional transmission investments.

Load Growth vs Load Loss

PacifiCorp expects to experience some load loss as a result of open access and competition. Results from RAMPP-3 and RAMPP-4 indicate that such losses could cause customer prices to increase, because the lower total load would result in less efficient use of the existing system. Most load growth will probably occur by acquiring customers through the competitive wholesale market. The company will not have an obligation to serve these new customers, due to their ability to choose their supplier, and can use the wholesale market to acquire power for them if needed.

Government Actions on Environmental Adders or Controls

RAMPP-4 found that the biggest risk in terms of impact on customer prices would be government action on environmental adders or controls. RAMPP-5 confirmed that result. The company continues to explore least cost methods to mitigate emissions.

The next chapter updates the inputs used in modeling. These updates allowed the company to develop a new base case using the most recent market information.

Chapter 4: Modeling Inputs for the New RAMPP-5 Base Case

This chapter reviews the changes made to the modeling inputs since preparing the RAMPP-4 Update base case. To prepare the new RAMPP-5 base case, the company reviewed all of the modeling inputs and updated those that changed.

The company made two significant adjustments to the input assumptions in the RAMPP-5 base case. Both of these adjustments better reflect the reality of open access and increasing competition. The first adjustment is in load growth. Open access and increasing competition will result in the loss of some regulated retail load over the next few years. The company currently anticipates a 10 to 20 percent loss by the end of the fifth year of the current planning horizon. Therefore, the RAMPP-5 base case includes an adjustment of removing 10 percent of the forecasted load at the fifth year (2002), with annual adjustments beginning in 1998 to smooth the path to that point. Although there will be load gains, those gains will occur in the company's competitive non-regulated business.

The second adjustment is in wholesale transactions. The IRP process includes all long-term wholesale transactions, which the company defines as wholesale sales and purchases of more than one year. RAMPP modeling assumes that when each sale or purchase contract expires, they are not renewed. If existing sales are higher than purchases, the impact is to increase the need for new resources for retail customers. If existing purchases are higher than sales, the impact is to decrease the need for new resources for retail customers. The company is increasingly active in this wholesale market, and temporary imbalances in long-term sales versus purchases can easily distort the need for new resources.

The company's intent has long been to sell any system surplus during the time period when retail customers do not need the power. This has enabled the company to acquire lost opportunity resources and profitably sell power from them on the wholesale market. As load growth catches up to the capacity of the existing system, the company's intent is to rely on the wholesale market to acquire the resources needed to meet the commitments made for long-term sales, either by making more long-term purchases, or by arranging for sufficient short-term power to meet the long-term sale commitments. The company's strategy is to have total long-term wholesale. Therefore, the sales balance total long-term wholesale purchases within five years. RAMPP-5 base case includes the assumption that this balancing occurs by the fifth year of the planning horizon, with annual adjustments in short-term purchases to reach a balance by 2002. This adjustment has the effect of removing the impact of wholesale transactions from the IRP process.

Major Input Assumption Changes Since the RAMPP-4 Update

In addition to the load forecast and wholesale adjustments discussed above, the company also made revisions to the following key inputs:

- Turbine upgrade amounts and timing,
- Gas wellhead and transportation prices to reflect current price levels,
- Short-term wholesale market prices,
- Cost of capital,
- Potential resource costs and transmission costs.

The following text discusses each of these areas and other input assumptions for the new RAMPP-5 base case.

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. The IPM is a capacity expansion, linear programming model that minimizes the present value of total resource costs. The modeling uses a 20 year planning horizon. However, it incorporates the impact of end effects when selecting a new resource because each case includes an additional 20 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 some of the years in the study period. These "run years" for the RAMPP-5 base case included each of the first ten years, then each fifth year. There were no code changes in the model between RAMPP-4 and RAMPP-5.

Reserve Margin

The company changed the planning reserve margin from 12 percent in RAMPP-4 to 10 percent in the RAMPP-4 Update. The new RAMPP-5 base case also used a 10 percent reserve margin. For three main reasons the company adopted a 10 percent reserve margin. First, access to wholesale market power to meet any short-term capacity needs results in less need for reserves. Second, gas-fired resources require less lead time to build. Third, load growth rates remain in the 2 percent range.

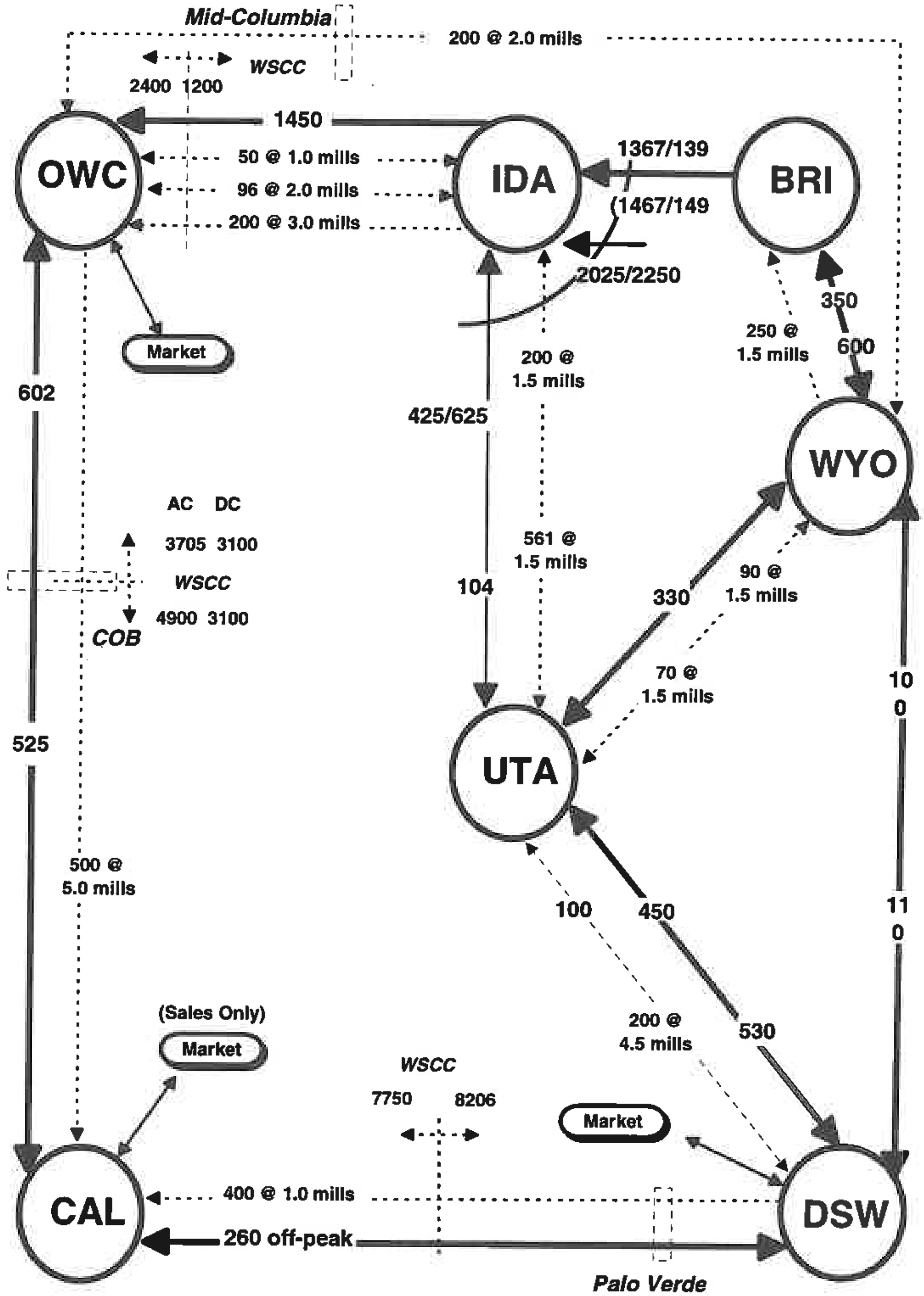
Geographic Areas and Transmission Limits

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. These constraints are particularly evident between the western and eastern parts of PacifiCorp's system. The model respects these transmission constraints between geographic areas. It dispatches new and existing resources and additional generating resources so that power flowing between geographic areas stays within these transmission limits.

The model uses simultaneous equations to find a least cost solution, considering alternative ways to meet load growth needs: existing resources within a geographic area, available resources from other areas that can move over the existing transmission network, and adding resources in a manner that respects the transfer limits.

Map 4-1 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. 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.

Map 4-1
Geographic Regions and Transfer Capabilities



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. This area includes the Centralia and Colstrip coal-fired plants, the Hermiston and James River cogeneration plants, the PacifiCorp and mid-Columbia hydro resources, the BPA peaking contracts, and other purchased power contracts.

- CAL: represents the California market.

- IDA: represents the Idaho load area; it includes Idaho-based hydro resources.

- BRI: represents the Bridger interconnection; it includes the Jim Bridger coal-fired plant. The model recognizes that the plant's location and nearby transmission connections with Idaho Power impost constraints on the system.

- WYO: represents load areas in eastern Wyoming; it includes the Dave Johnston and Wyodak coal-fired plants and some purchased power.

- UTA: represents load areas in southwestern Wyoming and in Utah; it includes 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 resources, and purchased power contracts.

- DSW: represents the Desert Southwest market; it includes the Cholla, Craig and Hayden thermal plants and power sales contracts in the Desert Southwest.

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 1,450 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

The 10 percent load loss adjustment discussed above occurs after the development of the load forecast. Therefore, the following discussion assumes no such adjustment.

The long range electricity sales forecast is an estimate of how much electricity retail customers (including both interruptible and regular sales for resale customers) will require in the next 20 years. For the IRP process, the company prepares an annual forecast for each customer class (residential, commercial, industrial, irrigation, and other customer classes) and then aggregates them. The company uses as inputs to the load forecasting model a consistent set of economic, demographic, and price projections (such as employment, population, and income) specific to each of the eight geographic areas, in seven states served by the company. The system wide forecast is the sum of the eight geographic area forecasts.

The company uses two basic forecasting methods: a combined econometric/end-use analysis for the residential and commercial classes, and an econometric forecast of the remaining customers groups.

After preparation of the energy forecast, the next step is preparation of an hourly load forecast for each of the eight geographic areas. This includes separate hourly forecasts for firm and interruptible customers in the two geographic areas where such forecasts are appropriate. This requires breaking the annual energy into monthly data on the basis of historic seasonal patterns. Further refinements develop weekly, daily and finally hourly load forecasts using historical patterns of energy use. Summing up the respective geographic area hourly forecasts produces hourly load forecasts for the Pacific and Utah Divisions and for the total company. The maximum total company load for each month is the peak load for the company, and the geographic area load at that time is the geographic area coincident peak. The maximum load for each geographic area during each month is the geographic area non-coincident peak. The forecasting techniques allow for the production of total, firm peak, and energy forecasts.

The following discussion of the load forecasting methodology contains two sections. The first section on economics and demographics describes the methodology used to generate the employment, population, and income forecasts. The second section on energy forecasts describes the methodology used to produce the annual residential, commercial, industrial, other sales forecasts, and the hourly forecasts.

Using Economic and Demographic Factors

Within the company's forecasting methodology, employment serves as the major determinant of future trends among the many economic and demographic variables used to drive the sales forecasting equations. Employment is also an input into the equations that forecast other economic and demographic variables. The importance of employment determination derives from regional export base theory. This assumes that the local economy consists of two distinct sectors: basic and non-basic.

The basic sector consists of those industries which produce goods destined for sales outside of the local area and whose market demand comes primarily from the national level. The employment categories in the basic category are: manufacturing, mining, agriculture, and federal government. For each historic year, and for each employment category and geographic area, a regional share is calculated for each industry. This regional share is used to forecast employment for each future period.

The non-basic sector theoretically represents those businesses whose output serves the local market and whose market demand is largely determined by the level of basic employment and output in the local economy. Non-basic employment categories are: transportation, communications, and public utilities; wholesale and retail trade; finance, insurance, and real estate; services; contract construction; state and local government; and non-farm proprietors. The company recognizes that a lot of commercial employment (traditionally treated as non-basic) has assumed a more basic nature. To recognize this, the equations which determine the non-basic employment forecasts include variables such as real gross national product, national output, housing starts, a time trend, along with basic employment. These equations regress employment in each of the categories as a function of variables which include some of the following: a lagged dependent variable; basic employment; and the national variables mentioned above. The inclusion of basic employment in the specification is a direct application of regional export base theory. As basic employment increases, it causes the non-basic sector to expand. The inclusion of the national variables in the specification reflects the theory that some non-basic employment behaves more like basic employment.

The relationship between the basic and non-basic sectors has not been constant over time. This is because as productivity, and hence real wages of basic sector workers has increased, their expanded purchasing power has caused the non-basic sector to develop more rapidly. A second reason is the changing preferences of consumers away from goods-producing or basic industries towards those which are more service-oriented.

Population per non-agricultural employee in each geographic area is forecast as a function of population per non-agricultural employee at the state level. When multiplied by the forecast of non-agricultural employment at the service territory level this ratio produces a population forecast.

The company includes two primary measures of income in the forecast of total electricity sales. Total personal income impacts energy utilization in the commercial sector. It consists of labor and proprietors' income, as well as income transfer payments, dividends, interest, and rent. Real per capita income measures purchasing power, which impacts energy choice in the residential sector. Together these two measures make up the company's economic forecasting system to project total personal income on a service territory basis.

Forecasting Energy Use

The major factor in forecasting future electricity sales is anticipated consumer use. The company predicts the level of use for each of its four customer classes: residential, commercial, industrial, and other. Each customer segment has particular end uses for electricity. To predict the overall level of future electricity use for any one customer class, the company looks at how the customers in that class use electricity and how much electricity they use. Future usage depends on:

- How many customers are currently equipped for each end use (the saturation level),
- How many additional customers will be equipped for that end use in the future (the penetration level),
- How much electricity is currently consumed (level of use) for that activity,
- How electricity consumption for that activity will change in the future.

The retail sales forecast uses the frozen efficiencies concept. This means that average usage per appliance are held at their 1996 levels throughout the forecast period. There are two exceptions: First, if government standards for new appliances become more stringent, then the company assumes that all appliances purchased after the date of the new standards will conform. Second, if a state has energy standards, or is considering standards such as Oregon's model conservation standards, the model assumes that new buildings will observe them.

The company's residential end-use forecasting model forecasts specific uses of electricity in the customer's home. It is a hybrid econometric-end use model. The model explicitly considers factors such as persons per household, fuel prices, per capita income, housing structure types, and other variables that influence residential customer demand for electricity. Residential demand is projected assuming fourteen end-uses: space heat, water heat, electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs, well pumps, and residual uses. Air conditioning can be either central, window, or evaporative (swamp cooler).

For each end use, the company looks first at saturation levels (the number of customers equipped for that end use) and how those saturation levels may change with demographic and economic factors. The saturation level for each end use is estimated based on company survey information. Then the company determines the penetration level given the economic and demographic future assumptions. In addition, using historic information, the company considers how many houses which currently have that end use are being demolished. The shorter lifetime of various appliances compared to the lifetime of a home is considered in determining the number of customers who use electricity for each end use.

The basic structure of the end-use model is to multiply forecast appliance saturations (percentage of homes with a particular appliance) by the appropriate housing stock. The result is then multiplied by the annual average electricity usage per appliance.

The commercial model forecasts electric energy use per square foot for each of seven end uses, for twelve commercial activities, for each of the nine geographic areas served by the company. The seven end-uses are space heating, water heating, space cooling, ventilation, refrigeration, lighting, & miscellaneous uses. The twelve vertical market segments (building types or commercial activities) are: communications/ utilities/transportation, food stores, retail stores, restaurants, wholesale trade, lodging, schools, hospitals, other health services, offices, services, and a miscellaneous category.

The saturation levels and usage per square foot for each of the commercial end uses have been estimated using data from commercial surveys, commercial customer consumption data, and engineering estimates. Usage per square foot for existing buildings is based on 1996 levels. Usage per square foot for new buildings has been estimated using engineering models and assuming current practices.

Each of the twelve vertical market segments are based on Standard Industrial Classifications (SIC). The basic structure of the end-use model is to multiply forecast end use saturations (percentage of square feet with a particular end use) by the appropriate amount of square footage. The result is then multiplied by the annual average electricity usage per square foot for each end use.

PacifiCorp's industrial sector is not dominated by a small number of firms or industries. The heterogeneous mix of customers and industries, combined with their widely divergent electricity consumption characteristics per unit of output, requires a substantial amount of disaggregation in developing a proper forecasting model for this sector. Accordingly, the industrial sector has been heavily disaggregated within the manufacturing and mining customer segments. The manufacturing sector is broken down into ten categories based upon the SIC System. These categories are food processing (SIC 20), lumber & wood products (SIC 24), paper & allied products (SIC 26), chemicals & allied products (SIC 28), petroleum refining (SIC 29), stone, clay & glass (SIC 32), primary metals (SIC 33), electrical machinery (SIC 36), transportation equipment (SIC 37). In all geographic areas, sales to a residual manufacturing category (all remaining manufacturing SIC codes) are forecast. Forecasts are only made for the major SICs within a particular geographic area, that is, when sales to that SIC within a geographic area are significant. The forecast for each industrial segment is not broken down into end uses because industrial customers in each segment tend to use electricity in the same way, although individual plant processes may vary.

The industrial sector is modeled using an econometric forecasting system. Conceptually, the best method of forecasting electricity sales would be on a per unit of output basis. However, this information is not available at the state service territory level. Accordingly, sales are forecast on a per employee basis. Therefore, electricity sales per employee are regressed in equations which may contain the following independent variables: a lagged dependent variable, relative price for fuel or energy used, national output in the industry, and a time trend. Not all equations contain all the independent variables. The results and the forecast of employment are used to arrive at the forecast of industrial electricity sales.

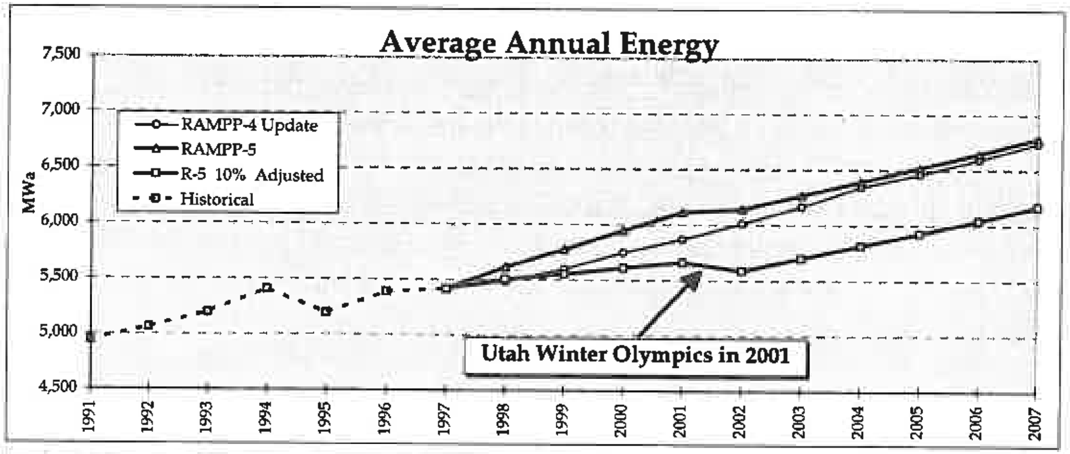
The disaggregated industrial sector allows the industry mix to vary over time. Each industry's employment is forecast to grow at a different rate and significant differences exist in both the level and trend of energy consumption per employee. Each industry also varies considerably in the magnitude of its response to changes in electricity and fossil fuel prices. Only with a disaggregated model can these differences be explicitly analyzed.

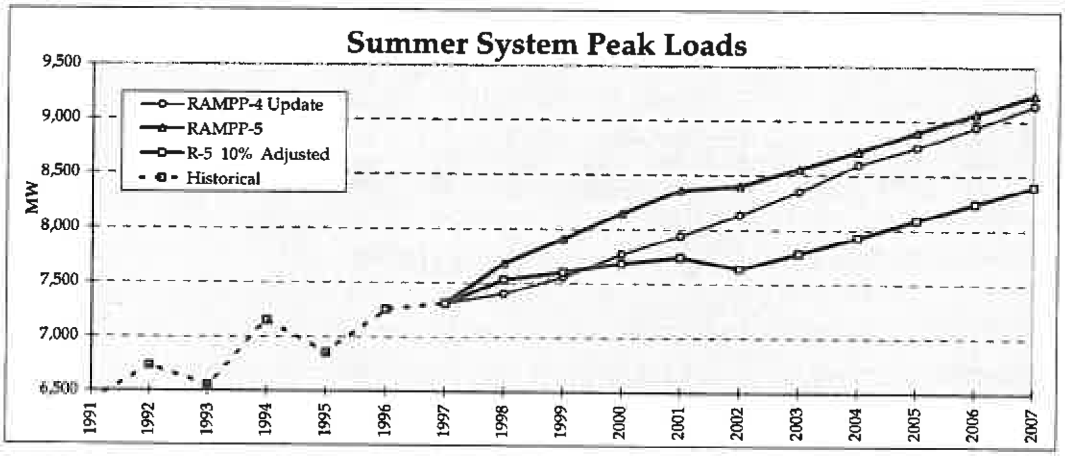
The company broke the industries' electricity consumption forecasts into two pieces, employment and megawatt hour consumption per employee before multiplying them together to arrive at total consumption. Intensity of use per employee assumes that capital stock, utilization rates, and technology are not fixed. Electricity use per employee will either increase or decrease as investments are made that substitute more or less electricity for all other factors of production. The inclusion of a lagged dependent variable, real electricity prices, and real fossil fuel prices in the electricity use in the employee equations captures this effect.

The other classes include irrigation, street and highway lighting, interdepartmental and other sales to public authorities. Electricity sales to these smaller customer classes are either forecast using econometric equations or the sales are held constant at historic levels.

The results of modeling annual sales for each of the customer classes are summed to develop a forecast of total sales for each of the nine geographic areas, for the Pacific & Utah divisions, and for the total company. Graph 4-2 shows the results for annual energy, summer peak and winter peak loads. The graph shows the levels used in the RAMPP-4 Update, the amounts developed for RAMPP-5 from the load forecasting process described above, and the result after the 10 percent adjustment for the new RAMPP-5 base case. The graph also shows historical amounts for 1991 through 1996.

Graph 4-2
RAMPP 5 Load Forecast





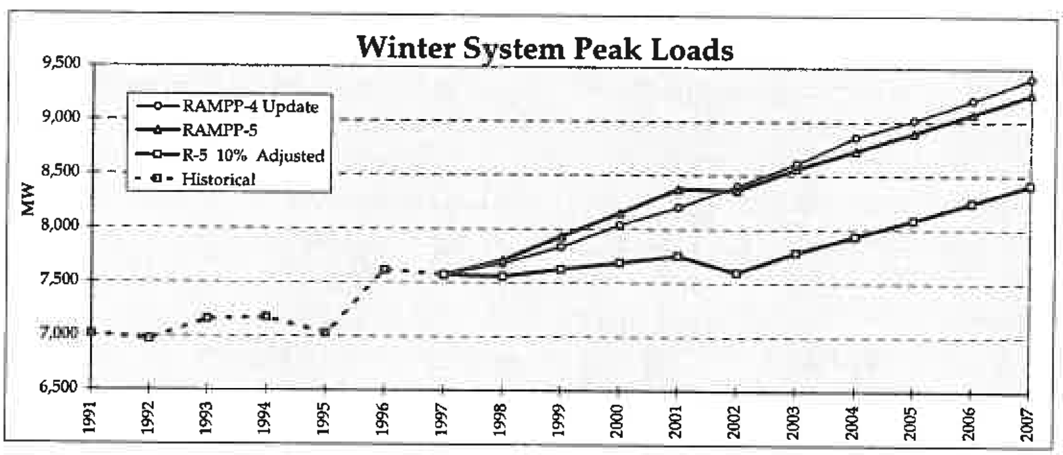


Table 4-3
RAMPP 5 Load Forecast

Total System Energy in MWa

Year	RAMPP 4 Update	RAMPP-5 without Adjustment	RAMPP-5 10% Adjustment	RAMPP-5 Historical
1991				4,946
1992				5,063
1993				5,198
1994				5,405
1995				5,190
1996				5,388
1997	5,417			
1998	5,484	5,614	5,504	
1999	5,595	5,776	5,554	
2000	5,748	5,948	5,611	
2001	5,870	6,114	5,661	
2002	6,013	6,145	5,587	
2003	6,168	6,271	5,701	
2004	6,348	6,395	5,813	
2005	6,463	6,522	5,929	
2006	6,598	6,651	6,046	
2007	6,745	6,792	6,174	
Average Annual Load Growth				
1998-2002	2.33%	2.29%	0.37%	
2003-2007	2.32%	2.02%	2.02%	

Summer System Peak Load

Year	RAMPP 4 Update	RAMPP-5 without Adjustment	RAMPP-5 10% Adjustment	RAMPP-5 Historical
1991				6,405
1992				6,734
1993				6,554
1994				7,151
1995				6,855
1996				7,257
1997	7,313			
1998	7,403	7,681	7,530	
1999	7,555	7,906	7,602	
2000	7,771	8,148	7,687	
2001	7,940	8,362	7,743	
2002	8,137	8,402	7,638	
2003	8,351	8,561	7,783	
2004	8,600	8,721	7,928	
2005	8,758	8,898	8,089	
2006	8,944	9,069	8,245	
2007	9,146	9,240	8,400	
Average Annual Load Growth				
1998-2002	2.39%	2.27%	0.36%	
2003-2007	2.37%	1.92%	1.92%	

Winter System Peak Load

Year	RAMPP 4 Update	RAMPP-5 without Adjustment	RAMPP-5 10% Adjustment	RAMPP-5 Historical
1991				7,019
1992				6,968
1993				7,156
1994				7,174
1995				7,030
1996				7,616
1997	7,575			
1998	7,679	7,710	7,559	
1999	7,834	7,933	7,628	
2000	8,039	8,151	7,690	
2001	8,204	8,375	7,755	
2002	8,399	8,362	7,602	
2003	8,614	8,565	7,786	
2004	8,858	8,731	7,937	
2005	9,016	8,898	8,089	
2006	9,203	9,077	8,252	
2007	9,404	9,260	8,418	
Average Annual Load Growth				
1998-2002	2.27%	2.05%	0.14%	
2003-2007	2.29%	2.06%	2.06%	

Table 4-3 shows the same information in numerical form, along with the average annual growth rates for the period during the adjustment (1998-2002) and for the years after the adjustment. The overall system is growing at about 2 percent a year. The 10 percent adjustment during the first five years significantly lowers that for those five years, after which the growth returns to its normal level.

Existing System

PacifiCorp's existing system for meeting retail load requirements includes existing power plants, turbine upgrades, and firm purchase and sale contracts. Table 4-4 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.

Table 4-4
Existing System - Summer Capacity (MW)
RAMPP-5 Base Case

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
Thermal Plants												
Carbon 1,2	175	175	175	175	175	175	175	175	175	175	175	175
Centralia 1,2	637	637	637	637	637	637	637	637	637	637	637	637
Cholla 4	380	380	380	380	380	380	380	380	380	380	380	380
Colstrip 3,4	140	140	140	140	140	140	140	140	140	140	140	140
Craig 1,2	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
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	454	454	454	454	454	454	454	454	454	454	454	454
Hunter 1,2,3	1,050	1,110	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Huntington 1,2	887	922	922	922	922	922	922	922	922	922	922	922
James River	50	50	50	50	50	50	50	50	50	50	50	50
Jim Bridger 1,2,3,4	1,395	1,403	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411
Naughton 1,2,3	700	700	700	700	700	700	700	700	700	700	700	700
Wyodak	268	268	268	268	276	276	276	276	276	276	276	276
Total Thermal	7,386	7,489	7,515	7,515	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523
Renewables												
Blundell Geothermal	23	23	23	23	23	23	23	23	23	23	23	23
BPA Peaking	1,100	1,100	925	925	925	925	925	925	925	925	925	925
BPA Supp Capacity	10	5	5	4	4	-	-	-	-	-	-	-
Hydro Idaho	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
Hydro Utah	36	36	36	36	36	36	36	36	36	36	36	36
Mid-Columbia	400	400	400	400	400	307	307	186	186	186	~~36~~	~~36~~
T&D Eff PPL	23	28	32	37	42	44	47	49	52	55	70	70
T&D Eff UPL	11	13	16	18	20	22	23	25	26	27	32	32
Water Budget	-	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	-	6	6	6	6	6	6	6	6	6	6	6
Total Renewables	2,578	2,586	2,418	2,424	2,431	2,338	2,342	2,225	2,229	2,233	2,103	2,103
Existing Generation	9,964	10,075	9,933	9,939	9,954	9,861	9,865	9,748	9,752	9,756	9,626	9,626

60 to 2018

400 -110 290

307 -110 -197

? None Listed in SEC 8-K

loss of 110 Priest Rapids

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58 - 153

About 68 percent of the company's capacity comes from company-owned thermal generating plants, 13 percent from hydro generation, and 19 percent from power purchases (mainly hydro-based). The company currently meets its energy requirements with about 72 percent thermal generation, 9 percent company-owned hydro, and 19 percent power purchases.

Changes in plant capacities for 1998 from the RAMPP-4 Update to RAMPP-5 are as follows:

- Huntington decreased capacity by 38 MW in 1998 and 3 MW by 2002,
- Hunter increased capacity by 6 MW in 1998 and 76 MW by 2002,
- Jim Bridger increased capacity by 8 MW in 1998 and 24 MW by 2002.

All other thermal plants decreased capacity by 6 MW in 1998 and 6 MW by 2002. Thus the total change in plant capacity from the RAMPP-4 Update to the new RAMPP-5 base case is a loss of 30 MW in 1998 but a gain of 91 MW by 2002.

In each case the increase or decrease in capacity related to the timing of turbine upgrades. The company's policy is to schedule turbine upgrades to coincide with major planned maintenance. The changes above also include re-rating other plants slightly to take into account actual operating experience. The RAMPP-5 base case assumptions include additional turbine upgrades. By 2002, additional turbine upgrades at Hunter, Jim Bridger, and Wyodak increased the existing system's capacity by 108 MW compared to the RAMPP-4 Update assumptions.

Assumption or FACT? What does

Part of the company's hydro resource system is the Mid-Columbia contract. This contract has a declining capacity from 400 MW in 1998 to 36 MW in 2012. For the new RAMPP-5 base case, the company adjusted the timing of contract capacity reductions. This change resulted in a loss of 93 MW in 2003, and a second loss of 121 MW in 2005 compared to the RAMPP-4 Update assumptions. There is no net change to the system only a timing change.

RAMPP-4 assumed 10 MW of wind capacity in 1997 and beyond; the RAMPP-5 base case assumes only 6 MW. As in previous RAMPP's, 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. The decrease in wind capacity is due to the indefinite postponement of the Columbia Hills wind project. Both PGE and PacifiCorp canceled the contracts they had with Kenetech Windpower due to avian issues. Kenetech has entered Chapter 11 bankruptcy proceedings, and may sell their project assets to another entity at some time in the future. For the Wyoming project, both Public Service of Colorado (PSCo) and Tri-State Generation & Transmission have dropped out of the project. PSCo dropped out due to their concern about avian mortality issues. Tri-State's 33 member board of directors did not approve moving forward with the project. The remaining owners are Eugene Water & Electric Board, and PacifiCorp who remain committed to the project. The project size is now approximately 42 MW, reflecting a reduction due to the shares that were to be owned by PSCo and Tri-State. BPA continues to be committed to the project and will be purchasing 15.32 MW of the output. All permits have been received and construction began in August of 1997. Completion is scheduled for the fall of 1998, well ahead of the expiration of production tax credits that expire on June 30, 1999.

The company currently plans to improve its thermal plants, hydro plants, transmission system, and distribution system. This involves modernization, equipment improvements, and regulatory compliance, but not upgrades to the capacity of particular units. As with any system improvement, the company assures that it can pass an avoided cost test before committing the capital.

Capital expenditures for ongoing refurbishment at the company's coal plants range from $6 to $10/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 $105 to $171/kW. New resources currently cost a minimum of $400/kW. Because the cost of extending plant life is so low relative to new resource costs, RAMPP-5 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-5 assumes the company will be successful in its relicensing efforts. However, the company recognizes that the success of relicensing will depend on many factors including the market price of energy; the economics of continued project operation under imposed new license conditions; as well as the economics of non-operational scenarios such as project decommissioning and project sale. The company will examine each hydroelectric facility and determine if the plant makes economic sense given these constraints.

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. 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.

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.

PacifiCorp is currently planning to implement cost effective steam turbine improvements of ten units at six plants: Hunter 3, Huntington 1 and 2, all four Bridger units, Wyodak, Dave Johnston 4, and Cholla 4.

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. Another effort will include a retrofit of the GE steam turbines at several other units in the system.

In the mid-1980s, the company operated the Hunter 3 boiler at steam production levels close to its design rate. 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. 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. Overall the cost to provide this added capacity at Hunter 3 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. 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 favor 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.

The company is still considering the cost effectiveness of repowering the Gadsby plant. Current market clearing prices are too low to justify the project at this time. However, a decision will probably occur in 2000, for startup in 2004-2006, although it is still possible that a 2002 startup may take place. To maintain this, the company plans to perform the environmental work necessary for a construction permit in 1998 and 1999.

PacifiCorp is an active participant in the wholesale market place. The company breaks wholesale transactions into two principle types, short-term and long-term. Included in the short-term designation are spot market transactions and short-term contracts. Spot market transactions occur hourly on a real time basis. Short-term contracts are for days or weeks but less than one year. The IPM model then determines an amount of short-term transactions that are cost effective for each hour at the prices input into the model. Short-term transactions also include contracts for power for the next week or month.

Long-term transactions are contractual obligations that have terms exceeding one year. As part of the update process the company reviewed each long-term-transaction to determine if modeling assumptions track actual transaction experience. In addition, the company adds new transactions and deletes expired contracts. Table 4-5 shows the current contracts and their annual capacities.

The following are the major changes in purchased power contracts that have occurred since the RAMPP-4 Update:

- Deseret was included in the RAMPP-4 Update as a single purchase contract. For RAMPP-5 modeling the company broke the contract into its three component parts.

- The Little Mountain cogeneration plant has been in the model since RAMPP-3. A new contract was signed with Great Salt Lake Minerals resulting in Little Mountain being re-classified as a long-term purchase rather than as an existing unit.

- Part of the company's hydro resource is the Mid-Columbia contract. This contract has declining capacity from 400 MW in 1998 to 36 MW in 2012. In RAMPP-5 the company adjusted the timing of contract capacity reductions.

- In the RAMPP-4 Update, the company assumed that the Carbon (Acme) contract, which was in the final stages of negotiations, would in fact be completed. The contract has since lapsed and is unlikely to be completed, for this reason, the contact was removed from the model.

- A long-term contract with Washington Water Power expires in 1997 and was removed from the modeling.

Table 4-5
Long-Term Wholesale Transactions (Summer MW)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
Purchases												
APS Sea Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-
APS Sea Ex (S)	(274)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)
Black Hills Capacity	68	68	68	68	68	68	68	68	68	68	-	-
BPA Southern Oregon	50	-	-	-	-	-	-	-	-	-	-	-
CSPE	39	19	18	17	16	-	-	-	-	-	-	-
Deseret Annual	208	250	248	245	-	-	-	-	-	-	-	-
Gem State	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
Idaho Load Control	150	150	150	150	150	150	150	150	150	150	150	150
IPC	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
PGE Cove	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
QF NW	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
San Juan Unit 4	21	21	21	21	21	21	21	21	21	21	21	-
Tri-State Basic	50	50	50	50	50	50	50	50	50	50	50	50
Tri-State Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Ex (S)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	-	-	-
USBR Greenspring	18	18	18	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (P)	50	50	50	50	50	50	50	50	50	50	-	-
WWP Seasonal Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-
WWP Summer Purchase	150	150	150	150	150	150	-	-	-	-	-	-
Purchased Power	1,024	996	992	970	723	708	558	558	558	558	440	419
Sales												
APPA	80	80	95	-	-	-	-	-	-	-	-	-
Azusa	10	-	-	-	-	-	-	-	-	-	-	-
Black Hills 1996	15	25	30	30	30	-	-	-	-	-	-	-
Black Hills Load	75	75	75	75	75	75	75	75	75	75	75	75
CDWR	100	100	100	100	100	100	100	-	-	-	-	-
Cheyenne	136	138	141	-	-	-	-	-	-	-	-	-
Clark County PUD	102	210	228	245	-	-	-	-	-	-	-	-
Cowlitz-BHP	22	22	22	22	22	-	-	-	-	-	-	-
ESI Kaiser	100	100	-	-	-	-	-	-	-	-	-	-
EWEB	50	50	50	-	-	-	-	-	-	-	-	-
Hinson	76	76	76	-	-	-	-	-	-	-	-	-
Nevada 1	140	-	-	-	-	-	-	-	-	-	-	-
Okanogan	5	5	5	5	-	-	-	-	-	-	-	-
Pan Energy	90	-	-	-	-	-	-	-	-	-	-	-
PECO	100	-	-	-	-	-	-	-	-	-	-	-
Plains Electric G&T	27	27	-	-	-	-	-	-	-	-	-	-
PSCol	176	176	176	176	176	176	176	176	176	176	176	176
Puget 2	200	200	200	200	200	200	-	-	-	-	-	-
Redding	50	50	50	50	50	50	50	50	50	50	-	-
SCE OWC	100	100	100	100	100	100	100	100	100	-	-	-
SCE Utah	100	100	100	100	100	100	100	100	100	-	-	-
Sierra 1	75	75	75	75	75	75	75	75	75	75	75	75
Sierra 2	75	75	75	75	75	75	75	75	75	75	-	-
SMUD	100	100	100	100	100	100	100	100	100	100	100	-
Springfield	45	45	45	45	45	45	45	45	45	45	45	-
UMPA 1	8	8	8	8	8	8	8	8	-	-	-	-
UMPA 2	11	14	19	21	25	25	25	25	25	25	25	25
WAPA 1	116	59	59	48	48	48	48	-	-	-	-	-
WAPA 2	75	75	75	75	75	75	75	-	-	-	-	-
Total Sales	2,593	2,525	2,444	2,091	1,845	1,793	1,593	1,370	1,362	1,112	987	842

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The following are major changes in wholesale sale contracts that have occurred since the RAMPP-4 Update:

- Revisions in the Clark County PUD contract decreased the energy requirement and increased capacity. In addition, the base capacity and energy provisions expired, resulting in additional supplemental capacity and energy sales.

- The Western Area Power Association (WAPA) long-term contract was amended, resulting in an increase in summer capacity of 15 MW and about 11 MWa of energy. This contract expires in 2004. A companion energy-only component, which shows in the table as WAPA Energy, was eliminated.

- Plains Electric G&T is a new wholesale sale. The sale has a winter capacity of 42 MW and 41 MWa of energy. The contract expires in the year 2000.

- Springfield, a current wholesale customer, has added a second contract. The new sale is an energy-only transaction and does not include a summer or winter reserve margin requirement. The energy requirement is 17 MWa and the contract expires in the year 2002.

- The company revised its modeling of the Cheyenne sale contract to more closely track actual experience. Summer coincident peak values increased 7 MW to 136 MW in 1998.

- In the RAMPP-4 Update the company included a sale to BHP Steel of 25 MW. This contract was re-negotiated to 22 MW and renamed the Cowlitz-BHP contract.

Demand-Side Management

For the RAMPP-5 base case, 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, and with the base case assumptions for the RAMPP-4 Update.

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. The company continued using the bundle approach for RAMPP-5.

Table 4-6 shows the bundles for each of the sectors: commercial, industrial, irrigation, and residential. The table shows the fully loaded cost for each of the bundles and the amount of DSM potential over the study period. It also shows the annual cut-off cost limits used in developing bundle sizes. The total amount of DSM potential offered to the model for the entire 20 year study period was 430 MWa.

Table 4-6 (Page 1 of 2)
DSM Total Costs and Savings Potential by Resource Bundle

Program Description	Resource Bundle Cut-Off Limits Lower ($/mwh)		Upper ($/mwh)		Levelized 40-Year TRC ($/mwh) *		1998-2018 Savings (Mwa)
COM-EXISTING-1-OWC	$	(100)	$	8	$	2.46	16.4
COM-EXISTING-2-OWC	$	8	$	15	$	15.92	10.8
COM-EXISTING-3-OWC	$	15	$	20	$	22.52	7.5
COM-EXISTING-4-OWC	$	20	$	22	$	28.28	2.3
COM-EXISTING-5-OWC	$	22	$	25	$	30.77	1.9
COM-EXISTING-6-OWC	$	25	$	27	$	34.96	0.3
COM-EXISTING-1-IDA	$	(100)	$	8	$	0.83	0.2
COM-EXISTING-2-IDA	$	8	$	15	$	15.39	0.1
COM-EXISTING-3-IDA	$	15	$	20	$	20.76	0.1
COM-EXISTING-4-IDA	$	20	$	22	$	25.67	0.0
COM-EXISTING-1-WY	$	(100)	$	8	$	1.29	1.6
COM-EXISTING-2-WY	$	8	$	15	$	14.66	0.8
COM-EXISTING-3-WY	$	15	$	20	$	21.13	0.4
COM-EXISTING-4-WY	$	20	$	22	$	73.19	0.0
COM-EXISTING-1-UT	$	(100)	$	8	$	1.88	48.3
COM-EXISTING-2-UT	$	8	$	15	$	15.57	15.5
COM-EXISTING-3-UT	$	15	$	20	$	23.55	26.1
COM-EXISTING-4-UT	$	20	$	22	$	28.07	0.2
COM-EXISTING-5-UT	$	22	$	25	$	31.29	4.6
COM-EXISTING-6-UT	$	25	$	27	$	34.40	1.2
COM-NEW-1-OWC	$	(100)	$	8	$	2.63	20.0
COM-NEW-2-OWC	$	8	$	15	$	15.70	17.2
COM-NEW-3-OWC	$	15	$	20	$	22.40	3.5
COM-NEW-4-OWC	$	20	$	22	$	27.89	2.5
COM-NEW-5-OWC	$	22	$	25	$	31.10	2.9
COM-NEW-6-OWC	$	25	$	27	$	33.82	0.3
COM-NEW-1-IDA	$	(100)	$	8	$	3.64	1.6
COM-NEW-2-IDA	$	8	$	15	$	14.47	0.8
COM-NEW-3-IDA	$	15	$	20	$	19.87	0.2
COM-NEW-4-IDA	$	20	$	22	$	26.31	0.0
COM-NEW-1-WY	$	(100)	$	8	$	2.73	6.0
COM-NEW-2-WY	$	8	$	15	$	15.37	3.0
COM-NEW-3-WY	$	15	$	20	$	21.25	0.8
COM-NEW-4-WY	$	20	$	22	$	27.18	0.0
COM-NEW-1-UT	$	(100)	$	8	$	3.93	16.5
COM-NEW-2-UT	$	8	$	15	$	14.99	10.4
COM-NEW-3-UT	$	15	$	20	$	21.95	5.2
COM-NEW-4-UT	$	20	$	22	$	27.22	0.0
COM-NEW-5-UT	$	22	$	25	$	30.65	0.9
COM-NEW-6-UT	$	25	$	27	$	34.28	0.3

Includes replacement cost and program admin costs and bulk-up

Table 4-6 (Page 2 of 2)
DSM Total Costs and Savings Potential by Resource Bundle

Program Description	Resource Bundle Cut-Off Limits Lower ($/mwh)	Upper ($/mwh)	Levelized 40-Year TRC ($/mwh) *	1998-2018 Savings (Mwa)
IND-EXISTING-1-OWC	$ -	$ 5	$ 9.21	19.3
IND-EXISTING-2-OWC	$ 5	$ 10	$ 20.64	6.8
IND-EXISTING-3-OWC	$ 10	$ 15	$ 28.30	3.6
IND-EXISTING-4-OWC	$ 15	$ 17	$ 35.72	8.7
IND-EXISTING-5-OWC	$ 17	$ 22	$ 46.22	6.6
IND-EXISTING-6-OWC	$ 22	$ 27	$ 58.20	6.0
IND-EXISTING-1-IDA	$ -	$ 5	$ 9.70	3.5
IND-EXISTING-2-IDA	$ 5	$ 10	$ 21.72	1.2
IND-EXISTING-3-IDA	$ 10	$ 15	$ 29.79	0.7
IND-EXISTING-4-IDA	$ 15	$ 17	$ 37.60	1.6
IND-EXISTING-1-WY	$ -	$ 5	$ 9.49	17.9
IND-EXISTING-2-WY	$ 5	$ 10	$ 21.26	6.3
IND-EXISTING-3-WY	$ 10	$ 15	$ 29.15	3.4
IND-EXISTING-4-WY	$ 15	$ 17	$ 36.79	8.1
IND-EXISTING-1-UT	$ -	$ 5	$ 9.82	19.0
IND-EXISTING-2-UT	$ 5	$ 10	$ 21.99	6.7
IND-EXISTING-3-UT	$ 10	$ 15	$ 30.16	3.6
IND-EXISTING-4-UT	$ 15	$ 17	$ 38.07	8.6
IND-EXISTING-5-UT	$ 17	$ 22	$ 49.27	6.5
IND-EXISTING-6-UT	$ 22	$ 27	$ 62.03	5.9
IRR-EXISTING-1-OWC	$ -	$ 32	$ 48.20	2.3
IRR-EXISTING-1-IDA	$ -	$ 32	$ 62.66	2.0
IRR-EXISTING-1-WY	$ -	$ 32	$ 48.20	0.0
IRR-EXISTING-1-UT	$ -	$ 32	$ 50.75	0.6
SGCENTS-OWC	$ -	$ 32	$ 17.03	4.9
SGCENTS-UT	$ -	$ 32	$ 17.03	1.1
SGCENTS-WY	$ -	$ 32	$ 17.03	2.4
SGCENTS-IDA	$ -	$ 32	$ 17.03	0.4
AP.RTRO-B1-OWC	$ -	$ 32	$ -	0.3
AP.RTRO-B1-UT	$ -	$ 32	$ -	1.7
AP.RTRO-B1-WY	$ -	$ 32	$ -	0.4
AP.RTRO-B1-IDA	$ -	$ 32	$ -	0.2
AP.RTRO-B2-OWC	$ -	$ 32	$ 28.85	7.1
AP.RTRO-B2-UT	$ -	$ 32	$ 28.85	7.6
AP.RTRO-B2-WY	$ -	$ 32	$ 28.85	1.2
AP.RTRO-B2-IDA	$ -	$ 32	$ -	0.7
AP.New-B1-OWC	$ -	$ 32	$ -	13.3
AP.New-B1-UT	$ -	$ 32	$ -	14.2
AP.New-B1-WY	$ -	$ 32	$ -	2.2
AP.New-B1-IDA	$ -	$ 32	$ 6.58	1.3
AP.New-B2-OWC	$ -	$ 32	$ 6.58	0.6
AP.New-B2-UT	$ -	$ 32	$ 6.58	0.8
AP.New-B2-WY	$ -	$ 32	$ 6.58	0.1
AP.New-B2-IDA	$ -	$ 32	$ -	0.1
AP.New-B3-OWC	$ -	$ 32	$ -	0.0
AP.New-B3-UT	$ -	$ 32	$ -	0.2
AP.New-B3-WY	$ -	$ 32	$ -	0.1
AP.New-B3-IDA	$ -	$ 32	$ 28.85	0.0

Commercial and industrial DSM measures fell into eight bundles for each segment, with the first three bundles including most of the resource. The eighth 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 company used the guidelines as established in the Oregon Commission'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, water usage, and labor savings.

Short-Term Market Prices

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. Short-term markets refer to transactions of one year or less, including spot energy transactions. Long-term includes transactions of more than one year duration. The model recognizes PacifiCorp's buying and selling activity in the short-term markets by assuming access to three regionally diverse wholesale markets. These three markets are the Pacific Northwest (OWC); the Desert Southwest (DSW) covering Utah, Four Corners and Palo Verde inter-connections; and California (CAL) through the North-South Intertie. Although the California market has a large capacity, transmission constraints severely restrict market access.

Short-term market activity does not occur in the Bridger, Idaho or Utah areas. Both purchases and sales can occur in OWC and the Desert Southwest. No purchases can occur in California but the model can sell in that area. These constraints reflect the company's purchase and sale activity in each of the geographic areas.

In the RAMPP-4 Update the company developed short-term market prices and natural gas prices independently. The company continued this practice when developing short-term market prices for the new RAMPP-5 base case. Short-term prices were determined from 1998 forward price curves. Forward price curves are a tabulation of option prices by brokers who trade in these markets. Prices for the OWC region are a combination of prices from the Mid-Columbia and COB price indexes. Prices in the Desert Southwest are from the Palo Verde price index. Table 4-7 shows prices for OWC and DSW, by season and by high and low load hours. It also shows the real annual escalation rate for the annual average prices. Graph 4-8 shows the same information in graph form.

Table 4-7
Wholesale Market Prices and Escalation
$1998 Mills/kWh

Penciled Numbers correspond to

	OWC				DSW				Average	Real
	DJF	MAM	JJA	SON						
6/97 - 5/98	Win	Spr	Sum	Fall	Win	Spr	Sum	Fall	Annual	Escalation
	17.72	18.28	17.35	18.92	21.42	21.94	31.01	32.41	24.67	
	High Load Hours (57% of hours)									%
1998	19.9	12.1	18.0	23.3	24.3	19.2	21.4	20.4	19.8	
1999	19.7	12.0	17.8	23.0	24.0	19.0	21.2	20.1	19.6	-1.1%
2000	19.7	12.0	17.9	23.0	24.0	19.1	21.2	20.2	19.6	0.2%
2001	20.5	12.5	18.6	24.0	25.1	19.9	22.1	21.0	20.5	4.2%
2002	20.6	12.6	18.7	24.1	25.2	20.0	22.2	21.1	20.6	0.5%
2003	21.5	13.1	19.5	25.1	26.2	20.8	23.1	22.0	21.4	4.1%
2004	22.7	13.8	20.5	26.5	27.6	21.9	24.4	23.2	22.6	5.4%
2005	22.7	13.8	20.5	26.5	27.6	21.9	24.4	23.2	22.6	0.0%
6/97 - 5/98	14.42	11.80	12.35	14.51	14.15	11.6	11.91	15.51	13.32	
	Low Load Hours (43% of hours)									%
1998	13.8	8.4	12.5	16.1	14.7	11.6	12.9	12.3	12.8	
1999	13.5	8.2	12.3	15.8	14.4	11.4	12.7	12.1	12.6	-1.7%
2000	13.3	8.1	12.1	15.5	14.2	11.2	12.5	11.9	12.3	-1.7%
2001	13.1	8.0	11.8	15.3	13.9	11.0	12.3	11.7	12.1	-1.7%
2002	12.8	7.8	11.6	15.0	13.7	10.9	12.1	11.5	11.9	-1.7%
2003	12.6	7.7	11.4	14.8	13.4	10.7	11.9	11.3	11.7	-1.7%
2004	12.4	7.6	11.2	14.5	13.2	10.5	11.7	11.1	11.5	-1.7%
2005	12.2	7.4	11.1	14.3	13.0	10.3	11.5	10.9	11.3	-1.7%
TOTAL	17.10	16.64	15.81	17.74	20.32	20.69	28.58	29.84	22.69	

Total peak =
W 20.18
S 20.39
S 24.82
F 28.42

Total off peak
W 14.26
S 11.73
S 12.03
F 15.05

PEAK = 6am - 10pm 16 hrs 67%

Off peak = 10pm - 6am 8 hrs 33%

WSCC

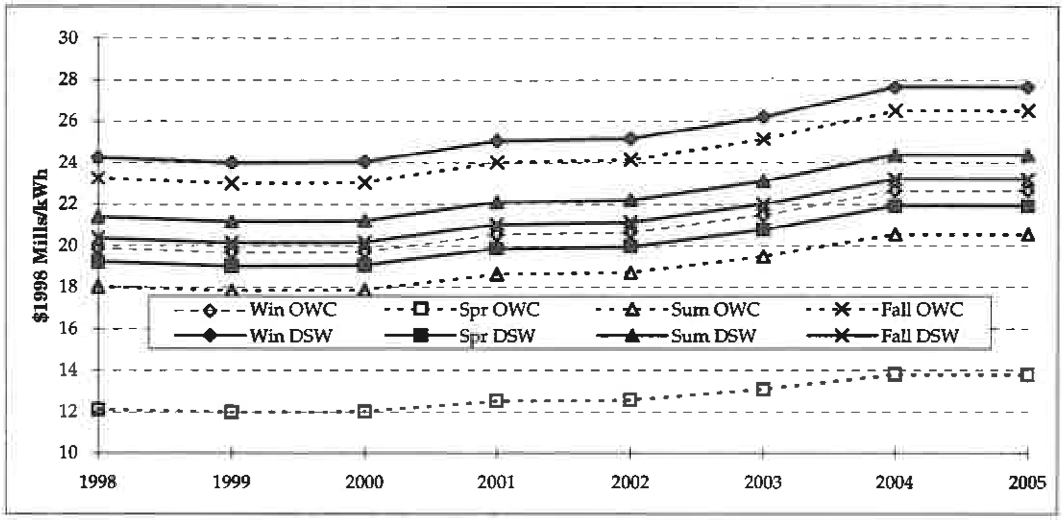
Summer 97 = 26.12 - Total Rev's / Total MWh

Fall 97 = 25.88

Winter 98 = 19.21

Spring 98 = 18.81

Graph 4-8
Wholesale Market Prices: High-Load Hours



OWC = COB (California Oregon Border) and Mid Columbia based prices.
DSW = Palo Verde based prices.

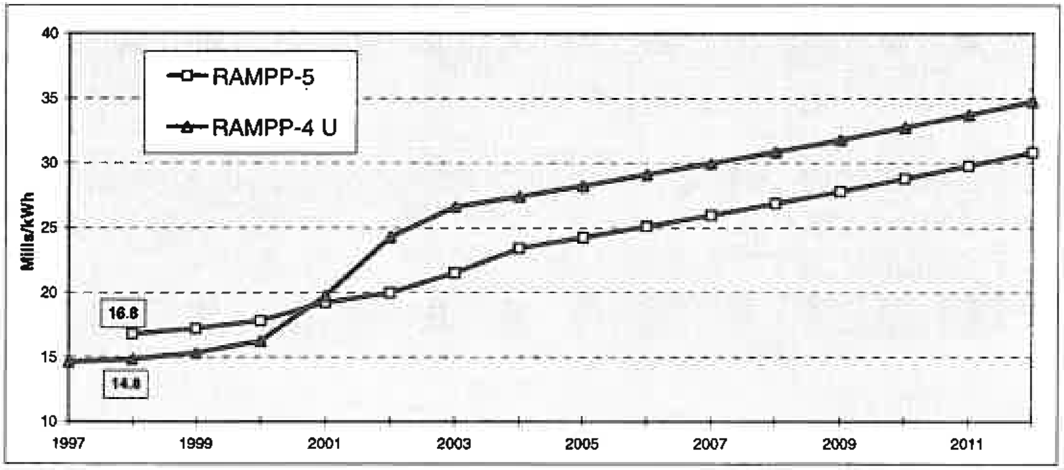
The new average annual price for 1998 of 19.8 mills/kWh is almost 12 percent higher than the RAMPP-4 Update price of 17.7 mills/kWh. However, the new average annual price for 2003 of 21.4 mills/kWh is 23 percent lower than the RAMPP-4 Update price of 27.8 mills/kWh. Whereas the RAMPP-4 Update prices assumed very high escalation rates in 2001 and 2002 (18.6 and 19.8 percent, respectively), the new prices assume more moderate escalation rates, never exceeding 5.4 percent.

Price escalation from the 1998 starting point is determined after considering projected WSCC load and resource balances, current market trends, and the experience of the company's energy traders.

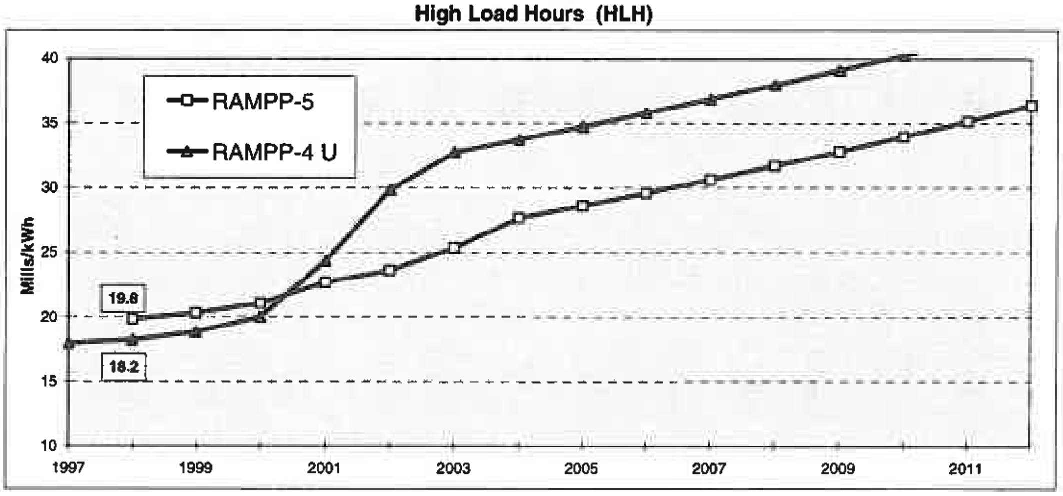
Graph 4-9 shows the average annual short-term market prices and price escalation rates for the new RAMPP-5 base case and for the RAMPP-4 Update. The RAMPP-5 prices start at a higher level but escalate at a slower rate.

Graph 4-9
RAMPP 5 Short Term Market Price and Price Escalation Rates

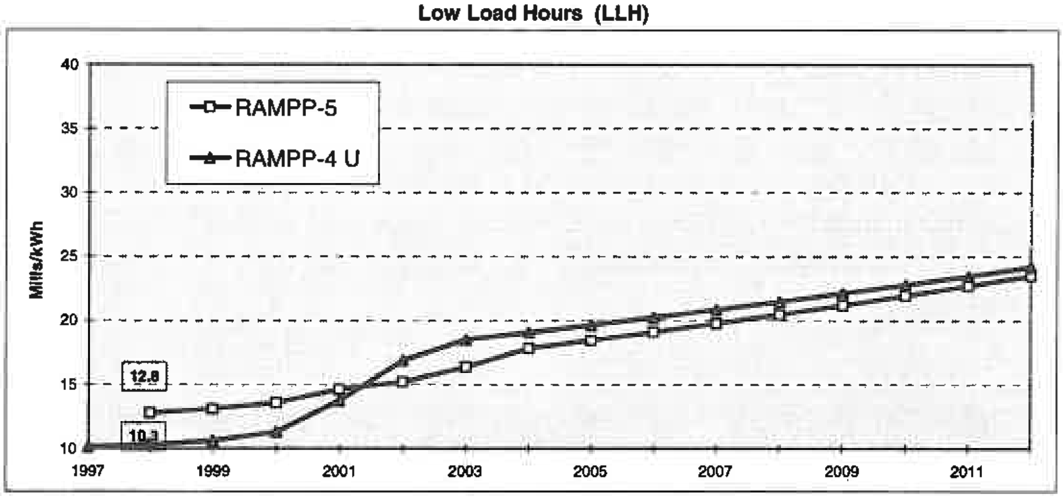
Annual Average (57% HLH + 43% LLH)



High Load Hours (HLH)



Low Load Hours (LLH)



The new RAMPP-5 base case 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 and in the RAMPP-4 Update). 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. Table 4-10 shows these amounts:

Table 4-10
Modeled Market by Geographic Area

	Available at Market Price	Available at Price + 2 mills/kWh
Purchases		
OWC	350 MW	100 MW
DSW	350 MW	100 MW
CAL	0	0
	Available at Market Price	Available at Price - 2 mills/kWh
Sales		
OWC	700 MW	200 MW
DSW	700 MW	200 MW
CAL	500 MW	100 MW

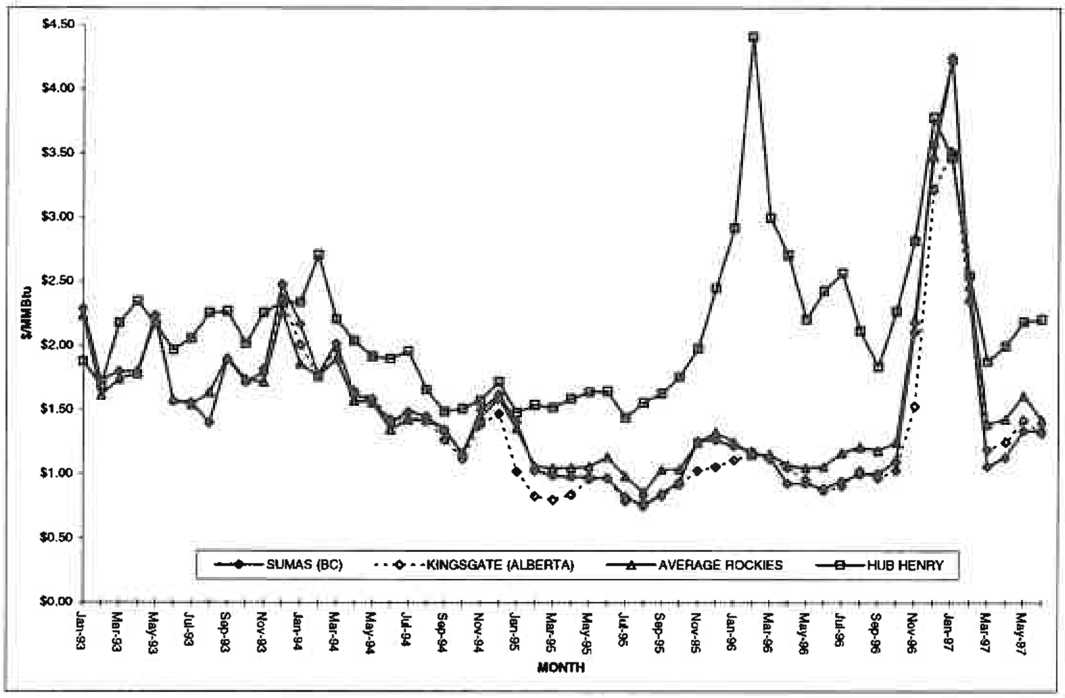
OWC, DSW, and CAL are the only areas where the model can make purchases or sales of short-term power. The model can make 100 MW more in short-term purchases in two of the areas at an incremental price 2 mills higher, and can make 200 MW more in short-term sales in each area at an incremental price 2 mills lower. This is an attempt to develop supply curves in the wholesale market.

Gas Prices

The modeling of gas prices for the new RAMPP-5 base case 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. Gas prices can be either at the wellhead, at the plantgate (into the pipeline), which includes costs for gathering and processing, or at the border, which includes costs for transportation and shrinkage (losses). PacifiCorp relies on three pipeline locations for its gas supplies: British Columbia at Sumas, Alberta at Kingsgate, and the Rockies through three sources (Questar, Northwest, and CIG). British Columbia and Alberta gas flows to the western part of the PacifiCorp system; gas from the Rockies flows to the eastern part of the PacifiCorp system.

Before addressing the two steps, a review of recent gas price history is helpful. Significant price differences remain among the major gas-producing regions. Graph 4-11 shows historical price comparisons and demonstrates the price differences between the Western Canadian basin, the Rockies and Henry Hub.

Graph 4-11
Natural Gas Price Projections
Historical Price Comparison ($/MMBtu)



The lack of sufficient pipeline capacity to Eastern Canada and to the Midwest has effectively constrained the flow of Rocky Mountain production, leaving a significant portion of current production still captive to the Western United States. As long as the price differentials continue to be in excess of pipeline expansion costs, producers will have strong financial incentives to finance new transport capacity. Table 4-12 shows proposed pipeline expansion projects, which should mitigate some of the large price differentials.

Table 4-12
RAMPP-5: NATURAL GAS PRICE PROJECTIONS
PROPOSED PIPELINE EXPANSION PROJECTS

Project	Date	Size (Mcf/Day)	Receipt	Destination
Pony Express	Late 1997	255,000	Wyoming	Kansas City
TransColorado	1998	300,000	Piceance, Colorado	New Mexico, Texas El Paso, Transwestern
Havasu Expansion	April, 1997	180,000	San Juan	El Paso
WIC Expansion	August 1997	192,000	Kanda, Wyoming	Nebraska
Colorado Interstate Gas	August 1997	68,000	Wind River, Wyoming	Rawlins
Southern Crossing	Nov. 1999	215,000	Alberta	Vancouver
Foothills - Northern Border	Nov. 1998	700,000	Alberta	Chicago
Alliance	Late 1999	1,325,000	Alberta/BC	Chicago

With the exception of last winter, natural gas prices in the Pacific Northwest have traded at significant discounts to Henry Hub. Several factors contributed to last winter's pricing abnormality. Working gas levels in western storage fields were about 70 percent of capacity at the start of the winter season. Mild winters over the last few years resulted in an underestimation of demand requirements. In addition, a reduction in long-term firm gas contracts and an increased reliance on index and short-term contracts have increased price volatility.

The first step in developing gas prices for use in RAMPP-5 is determination of a beginning 1998 price for both the west side of the system and the east side. A market solicitation on July 23, 1997, produced border prices for Sumas in Alberta ($1.56/MMBtu) and Kingsgate in British Columbia ($1.48/MMBtu). Their average ($1.52) represents the price for the westside of the PacifiCorp system. For the eastside, the Questar plantgate price for 1998 of $1.71 is comparable. For both, the only additional cost before the end user is transportation. The result is a raw 1998 gas price for the west side of $1.52/MMBtu and for the eastside $1.71/MMBtu.

The modeling of a gas price escalation rate for RAMPP-5 used a hybrid approach similar to that used in the RAMPP-4 Update. As in the RAMPP-4 Update, the company used the concept of full cycle replacement costs for the time period through 2006, and traditional independent price projections for the years after 2006. 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. As in the RAMPP-4 Update, the period through 2006 reflects the trending of wellhead gas prices towards full cycle recovery costs from current prices. Once at full recovery cost, wellhead gas prices then escalate using escalation rates from independent price projections.

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 well head costs exists. During the initial ten year period, the escalation rate represents the annual percentage increase necessary to move from current prices to full-cycle replacement costs in 2006. Table 4-13 shows the components for full cycle replacement costs in British Columbia, Alberta, and the Rockies in both 1998 and 2006 dollars.

Unlike the RAMPP-4 Update, RAMPP-5 incorporates expected ongoing technological improvements. Significant technological improvements in exploration and development drilling have reduced production costs. Many of the independent natural gas price forecasters cite technology improvements, in addition to improved gas recovery, as the leading contributors for the lowering of long-term price growth rates. Approximately 65 percent of the full-cycle replacement costs can be attributed to technological related factors. According to Barakat and Chamberlin, expected technological improvements should reduce technologically related cost by as much as 2 percent a year.

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, thus producing lower long-term escalation rates for gas prices.

Several of the major natural gas price growth studies used in the RAMPP-4 Update were updated during 1997. Table 4-14 shows the results of the studies used by the company. These include reports by the gas industry, government, and independent organizations.

Table 4-13
NATURAL GAS PRICE PROJECTIONS
FULL CYCLE REPLACEMENT COSTS

$1998 $/MMBtu

	BRITISH COLUMBIA	ALBERTA	ROCKIES
EXPLORATION DRILLING	$0.20	$0.25	$0.29
DEVELOPMENT DRILLING/FACILITIES	$0.35	$0.30	$0.57
LEASE OPERATING EXPENSE	$0.15	$0.10	$0.19
FINANCING	$0.12	$0.12	$0.16
ROYALTY	$0.17	$0.16	$0.24
TAXES	$0.11	$0.11	$0.11
TOTAL WELLHEAD COSTS	$1.10	$1.04	$1.55

$2006 $/MMBtu

	BRITISH COLUMBIA	ALBERTA	ROCKIES
EXPLORATION DRILLING	$0.24	$0.30	$0.34
DEVELOPMENT DRILLING/FACILITIES	$0.43	$0.36	$0.69
LEASE OPERATING EXPENSE	$0.18	$0.12	$0.23
FINANCING	$0.15	$0.15	$0.19
ROYALTY	$0.20	$0.19	$0.29
TAXES	$0.13	$0.13	$0.13
TOTAL WELLHEAD COSTS	$1.33	$1.25	$1.87

SOURCE:
BARAKAT & CHAMBERLIN, INC.

Table 4-14
SUMMARY OF LONG TERM ESCALATION RATES
FOR WELLHEAD PRICES: POST 2006

LOW GROWTH RATE AVG	-0.2%
GRI	-0.20%

HIGH GROWTH RATE AVG	1.8%
DRI	1.80%

MEDIUM GROWTH RATE AVG	0.70%
AGA	0.43%
DOBSON	0.75%
WEFA: ROCKIES	0.58%
WEFA: ALBERTA	0.80%
DOE/EIA	0.94%

INDEPENDENT GAS PRICE GROWTH STUDIES

PUBLICATION	DATE	LONG TERM PRICE PROJECTIONS & ESCALATION RATES (%/YEAR) 2000	2005	2010	2015	2020	
GRI BASELINE PROJECTION	JANUARY 1997	$1.89	$2.05	$2.33	$2.74		NOMINAL
		$1.74	$1.67	$1.64	$1.64		REAL
		2.34%	0.75%	0.38%	0.28%		%
DEPARTMENT OF ENERGY/EIA ANNUAL ENERGY OUTLOOK	JANUARY 1997						%
		$1.82	$1.94	$2.01	$2.13		REAL
		2.48%	1.88%	1.49%	1.41%		%
DRI: WORLD ENERGY SERVICE U.S. OUTLOOK SUPPLEMENT	SPRING 1997	$1.82	$2.33	$3.01	$3.96		NOMINAL
		$1.66	$1.83	$1.98	$2.19		REAL
		-7.32%	-2.27%	-0.91%	-0.14%		%
AMERICAN GAS ASSOCIATION "THE GAS ENERGY SUPPLY & DEMAND OUTLOOK 1996 - 2015"	JANUARY 1997	$1.94	$2.03	$2.12	$2.12		REAL
		-3.74%	-1.90%	-0.46%	-0.34%		%
WEFA	FALL/1995	$1.70	$1.85	$1.91	$1.96	$2.02	REAL
		-1.96%	0.06%	0.27%	0.33%	0.39%	%
	WINTER/1996	$1.18	$1.33	$1.38	$1.44	$1.50	REAL
		5.29%	3.69%	2.63%	2.16%	1.88%	%
DOBSON RESOURCE MANAGEMENT SURVEY OF HYDROCARBON PRICE FORECASTS UTILIZED BY CANADIAN PETROLEUM CONSULTANTS AND CANADIAN BANKS	JANUARY 1997	$1.43	$1.84	$2.20			NOMINAL
		$1.31	$1.46	$1.50			REAL
		5.77%	3.46%	2.33%			%
		$1.22	$1.64	$1.99			NOMINAL
		$1.12	$1.29	$1.36			REAL
		7.07%	4.48%	3.11%			%

Gas transportation and storage costs have been updated to reflect the current released capacity values. In the case of both Northwest Pipeline and PGT, longer term rates have been escalated to represent estimated expansion costs. Transportation costs for the westside are $0.17/ and for the eastside are $0.22. These compare to $0.36/MMBtu and $0.24, respectively, for the RAMPP-4 Update. The westside storage charges have been updated to reflect the expected costs associated with the Wild Goose storage charges. This project should be completed in 1998. The eastside storage project rates have been modified to reflect the current tariff rates associated with Clay Basin storage. In addition to the variable cost of storage, some additional costs are fixed. The company converted these fixed costs to $/kW year for ease of modeling.

Table 4-15 shows the year-by-year delivered natural gas prices in dollars per MMBtu as input into the model for the westside and the eastside. Graph 4-16 shows the same information.

Table 4-15

Delivered Natural Gas Prices in $/MMBtu

Year	Pacific NW (West Side)				Mountain (East Side)			
	Gas Price	Transportation	Total $1998	Nominal $	Gas Price	Transportation	Total $1998	Nominal $
1998	$1.52	$0.18	$1.69	$1.69	$1.71	$0.22	$1.93	$1.93
1999	$1.54	$0.18	$1.71	$1.77	$1.73	$0.22	$1.96	$2.02
2000	$1.55	$0.18	$1.73	$1.85	$1.76	$0.22	$1.98	$2.12
2001	$1.57	$0.18	$1.74	$1.93	$1.79	$0.22	$2.01	$2.23
2002	$1.58	$0.21	$1.79	$2.06	$1.82	$0.22	$2.04	$2.34
2003	$1.59	$0.21	$1.81	$2.15	$1.84	$0.22	$2.07	$2.45
2004	$1.61	$0.21	$1.82	$2.24	$1.87	$0.22	$2.10	$2.58
2005	$1.62	$0.21	$1.84	$2.34	$1.90	$0.22	$2.13	$2.70
2006	$1.64	$0.21	$1.85	$2.44	$1.93	$0.22	$2.16	$2.84
2007	$1.65	$0.32	$1.97	$2.69	$1.97	$0.22	$2.19	$2.98
2008	$1.65	$0.32	$1.97	$2.78	$1.97	$0.22	$2.20	$3.10
2009	$1.66	$0.31	$1.97	$2.88	$1.98	$0.22	$2.21	$3.22
2010	$1.67	$0.30	$1.97	$2.98	$1.99	$0.22	$2.21	$3.35
2011	$1.67	$0.30	$1.97	$3.09	$2.00	$0.22	$2.22	$3.48
2012	$1.68	$0.29	$1.97	$3.19	$2.01	$0.22	$2.23	$3.61
2013	$1.69	$0.29	$1.97	$3.31	$2.02	$0.22	$2.24	$3.75
2014	$1.69	$0.28	$1.98	$3.43	$2.03	$0.22	$2.25	$3.90
2015	$1.70	$0.28	$1.98	$3.55	$2.04	$0.22	$2.26	$4.06
2016	$1.71	$0.27	$1.98	$3.68	$2.05	$0.22	$2.27	$4.21
2017	$1.72	$0.26	$1.98	$3.81	$2.06	$0.22	$2.28	$4.38

Average Annual Escalation

1998-2007	0.93%	6.93%	1.70%	5.26%	1.57%	0.00%	1.40%	4.95%
2008-2017	0.40%	-1.94%	0.05%	3.55%	0.45%	0.00%	0.41%	3.92%

Graph 4-16

Nominal Gas Prices ($/MMBtu)

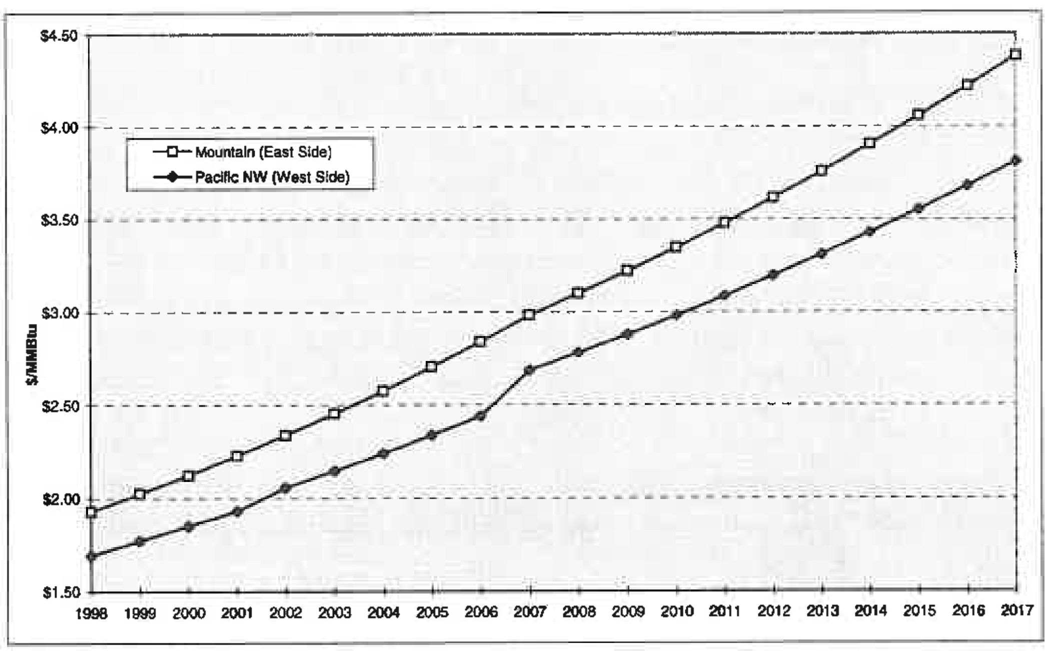


Table 4-17
Comparison of RAMPP 5 Vs RAMPP-4 Update
Pacific NW Gas and Transportation Prices

Nominal 1998 Prices

Variable Costs in $/MMBtu	Combined Cycle		Simple Cycle	
	RAMPP-5	R-4 Update	RAMPP-5	R-4 Update
1998 Gas Price	1.52	1.36	1.52	1.36
Transportation	0.17	0.36		
Storage			0.06	0.10
Total Variable	1.69	1.72	1.58	1.46

Fixed Costs $/kW-yr	Combined Cycle		Simple Cycle	
	RAMPP-5	R-4 Update	RAMPP-5	R-4 Update
Total Fixed	-	-	$ 13.91	$ 12.85

Nominal 2002 Prices

Variable Costs in $/MMBtu	Combined Cycle		Simple Cycle	
	RAMPP-5	R-4 Update	RAMPP-5	R-4 Update
2002 Gas Price	1.82	1.72	1.82	1.72
Transportation	0.24	0.42		
Storage			0.07	0.11
Total Variable	2.06	2.14	1.88	1.83

Fixed Costs $/kW-yr	Combined Cycle		Simple Cycle	
	RAMPP-5	R-4 Update	RAMPP-5	R-4 Update
Total Fixed	-	-	$ 15.96	$ 14.75

Table 4-17 compares gas price assumptions used in the new RAMPP-5 base case to those used in the RAMPP-4 Update sensitivities. It provides the comparison for both a combined cycle and a simple cycle gas-fired plant. For nominal 1998 prices for a combined cycle unit, although the commodity gas price increased, transportation costs decreased by a greater amount, resulting in a slightly lower total variable cost. For a simple cycle, the decrease in storage costs did not compensate for the higher gas price, resulting in a higher total variable cost. The same pattern held for nominal 2002 prices.

PacifiCorp developed the above gas price estimates and forecast during August 1997. The company recognizes that due to the changing nature of gas markets, the above estimates and forecasts could be different if finalized at an earlier or later point in time.

Cost of Capital

Cost of capital determines the annualization rate used in calculating the total resource cost for each resource in the portfolio, both demand-side and supply-side. A higher cost of capital results in a higher TRC. The nominal cost of capital used for the RAMPP-5 base case is 10.26 percent. This is capital costs in the traditional format used by regulators. However, it is a mix of pre-tax and after-tax capital costs. Debt is on a pre-tax basis, while preferred and common equity costs are on an after-tax basis. From a financial analysis perspective, investment alternatives are evaluated on the present value of a project's after-tax cash flows. To calculate the nominal discount rate, an after tax cost of capital is calculated by removing income taxes from the cost of debt. The resulting nominal discount rate is 9.08 percent. After adjusting for inflation the real after tax discount rate is 5.39 percent.

The real cost of capital increased from 4.8 percent in the RAMPP-4 Update to 5.39 percent. Inflation increased from 3.0 percent in the RAMPP-4 Update to 3.50 percent. DRI's forecast of inflation over the next 20 years increased since their forecast created about a year ago. Table 4-18 shows the RAMPP-4 Update and RAMPP-5 components.

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. Table 4-19 showing the entire portfolio of potential resources includes a column showing the transmission cost to connect each resource to the existing transmission grid. The company does not believe that the costs used in RAMPP-4 have increased or decreased since RAMPP-4, other than for two years of inflation.

Table 4-18
Comparison of RAMPP 5 Vs RAMPP-4 Update
Cost of Capital

RAMPP-5	Capital Structure	Cost	Weighted Cost Pre-tax	Weighted Cost After-tax
Debt	38%	8.2%	3.10%	1.93%
Preferred Stock	4%	7.8%	0.31%	0.31%
Market Equity	58%	11.8%	6.84%	6.84%
Total	100%		10.26%	**9.08%**

Inflation	3.5%
Real Discount Rate	5.39%

RAMPP-4 Update	Capital Structure	Cost	Weighted Cost Pre-tax	Weighted Cost After-tax
Debt	46%	7.2%	3.30%	2.05%
Preferred Stock	7%	6.8%	0.47%	0.47%
Market Equity	47%	11.5%	5.41%	5.41%
Total	100%		9.18%	**7.93%**

Inflation	3.0%
Real Discount Rate	4.80%

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 39 percent and costs for coal-based power plants declined about 18 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 1998 dollar 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, are 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.

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

Table 4-19 shows the potential resources sorted by TRC and each of the cost components. 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 4-19 (Page 1 of 2)
Potential Resources Sorted by Total Resource Costs

Short Name	Description	Unit Size MW: Unit Size	Unit Size MW: Max Annual	Unit Size MW: MWs Avail.	1st Year Avail	Forced Outage Rate	Maint. Outage Rate	Full Load Heat Rate BTU/kWh: Incremental	Full Load Heat Rate BTU/kWh: Average	Emissions lbs/MMBtu: NOX	Emissions lbs/MMBtu: TSP	Emissions lbs/MMBtu: CO2	Capital Cost: Unit Cost	Capital Cost: Trans-mission
OC2	OWC Cogen 2	234	470	1,390	2002	3.3%	3.8%	6,200	6,800	0.016	0.003	118.0	$ 430	$ 60
OC1	OWC Cogen 1	25	160	215	2002	3.3%	3.8%	4,300	5,500	0.016	0.003	118.0	$ 1,009	$ -
IC2	Idaho Cogen 2	198	230	230	2002	3.3%	3.8%	6,200	6,800	0.016	0.003	118.0	$ 506	$ 75
UC2	Utah Cogen 2	198	400	1,780	2002	3.3%	3.8%	6,200	6,800	0.016	0.003	118.0	$ 506	$ 75
OCC	OWC Combined Cycle	234	450	unlimit	2002	3.3%	3.8%	6,370	6,701	0.016	0.003	118.0	$ 400	$ 75
IC1	Idaho Cogen 1	30	30	30	2002	3.3%	3.8%	4,300	5,500	0.016	0.003	118.0	$ 1,187	$ -
UC1	Utah Cogen 1	20	20	15	2002	3.3%	3.8%	4,300	5,500	0.016	0.003	118.0	$ 1,187	$ -
ICC	Idaho Combined Cycle	198	450	unlimit	2002	3.3%	3.8%	6,370	6,701	0.016	0.003	118.0	$ 471	$ 90
UCC	Utah Combined Cycle	198	450	unlimit	2002	3.3%	3.8%	6,370	6,701	0.016	0.003	118.0	$ 471	$ 90
WCC	Wyo Combined Cycle	182	450	unlimit	2002	3.3%	3.8%	6,370	6,701	0.016	0.003	118.0	$ 500	$ 100
UG1	Utah PC Hunter 4 $20/Ton	400	400	400	2004	4.0%	4.5%	9,560	10,060	0.100	0.015	206.0	$ 1,180	$ 54
WG1	Wyo PC Wyodak 2	325	264	264	2004	4.0%	4.5%	9,560	10,060	0.100	0.015	206.0	$ 1,380	$ 544
WG2	Wyo Coal $6.70/Ton	325	330	unlimit	2004	4.0%	4.5%	9,560	10,060	0.100	0.015	206.0	$ 1,380	$ 544
UCY	Utah IGCC Hunter 4	262	262	262	2004	5.0%	4.5%	7,980	8,400	0.070	0.015	206.0	$ 1,301	$ 54
WCY	Wyo IGCC Wyodak 2	262	210	210	2004	5.0%	4.5%	7,980	8,400	0.070	0.015	206.0	$ 1,301	$ 544
WCZ	Wyo IGCC CT	262	262	unlimit	2004	5.0%	4.5%	7,980	8,400	0.070	0.015	206.0	$ 1,301	$ 544
UG2	Utah Coal $23.25/Ton	400	400	1,250	2004	4.0%	4.5%	9,560	10,060	0.100	0.015	206.0	$ 1,380	$ 150
UCZ	Utah IGCC CT	262	262	-	2004	5.0%	4.5%	7,980	8,400	0.070	0.015	206.0	$ 1,301	$ 150
UG3	Utah Coal $27.00/Ton	400	400	1,250	2004	4.0%	4.5%	9,560	10,060	0.100	0.015	206.0	$ 1,380	$ 150
OGT	OWC Geothermal	50	100	300	2001	1.5%	3.8%	10,000	10,000	-	-	-	$ 2,276	$ 100
UGT	Utah Geothermal	50	100	300	2001	1.5%	3.8%	10,000	10,000	-	-	-	$ 2,276	$ 100
UW1	Utah Wind	50	100	200	2000	5.0%	0.0%	-	-	-	-	-	$ 1,075	$ 140
WW1	Wyo Wind	50	100	200	2000	5.0%	0.0%	-	-	-	-	-	$ 1,075	$ 140
OCT	OWC Simple Cycle CT	159	370	unlimit	2002	1.5%	0.0%	10,340	10,879	0.090	0.003	118.0	$ 315	$ 75
UCT	Utah Simple Cycle CT	135	370	unlimit	2002	1.5%	0.0%	10,340	10,879	0.090	0.003	118.0	$ 371	$ 90
WCT	Wyo Simple Cycle CT	124	320	unlimit	2002	1.5%	0.0%	10,340	10,879	0.090	0.003	118.0	$ 394	$ 100
IET	Idaho Bridger Trans	500	500	1,000	2002	0.0%	0.0%	-	-	-	-	-	$ -	$ 150
IEV	Idaho Htr/Id Trans L	500	500	1,000	2002	0.0%	0.0%	-	-	-	-	-	$ -	$ 150
OET	OWC Bridger Trans L	500	500	1,000	2002	0.0%	0.0%	-	-	-	-	-	$ -	$ 150
UET	Utah Wyo/Ut Tran L	500	500	1,000	2002	0.0%	0.0%	-	-	-	-	-	$ -	$ 300
OPS	OWC Pump Storage	200	200	500	2003	1.0%	0.0%	-	-	-	-	-	$ -	$ 302
UPS	Utah Pumped Storage	200	200	200	2003	1.0%	0.0%	-	-	-	-	-	$ 716	$ 100
USR	Utah Solar	50	100	1,000	1999	0.0%	0.0%	-	-	-	-	-	$ 4,763	$ -

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Table 4-19 (Page 2 of 2)
Potential Resources Sorted by Total Resource Costs

Short Name	Description	Capital Cost $/kW Total Cap Cost	Capital Cost $/kW Payment Factor	Capital Cost $/kW Annual Pmt $/kW-Yr	Fixed Cost Total O&M	Fixed Cost Ttl Fixed $/kW-Yr	Convert to Mills Conversion Utilization	Convert to Mills Ttl Fixed Mills/kWh	Energy Cost in 2003 ($1998) 1st Year $/MMBtu	Energy Cost in 2003 ($1998) Levelized $/MMBtu	Energy Cost in 2003 ($1998) Levelized Mills/kWh	Variable O&M Mills/kWh	Total Resource Cost
OC2	OWC Cogen 2	$ 490	9.36%	$ 45.91	$ 5.67	$ 51.57	85%	6.93	1.81	1.95	12.10	0.56	19.59
OC1	OWC Cogen 1	$ 1,009	9.36%	$ 94.43	$ 5.67	$ 100.09	85%	13.44	1.81	1.95	7.77	0.56	21.78
IC2	Idaho Cogen 2	$ 581	9.36%	$ 54.42	$ 6.66	$ 61.08	85%	8.20	2.07	2.23	13.82	0.56	22.58
UC2	Utah Cogen 2	$ 581	9.36%	$ 54.42	$ 6.66	$ 61.08	85%	8.20	2.07	2.23	13.82	0.56	22.58
OCC	OWC Combined Cycle	$ 475	9.36%	$ 44.46	$ 29.00	$ 73.46	85%	9.87	1.81	1.95	12.44	0.50	22.80
IC1	Idaho Cogen 1	$ 1,187	9.36%	$ 111.09	$ 6.66	$ 117.76	85%	15.81	2.07	2.23	9.58	0.56	25.96
UC1	Utah Cogen 1	$ 1,187	9.36%	$ 111.09	$ 6.66	$ 117.76	85%	15.81	2.07	2.23	9.58	0.56	25.96
ICC	Idaho Combined Cycle	$ 561	9.36%	$ 52.47	$ 34.12	$ 86.59	85%	11.63	2.07	2.23	14.20	0.50	26.33
UCC	Utah Combined Cycle	$ 561	9.36%	$ 52.47	$ 34.12	$ 86.59	85%	11.63	2.07	2.23	14.20	0.50	26.33
WCC	Wyo Combined Cycle	$ 600	9.36%	$ 56.16	$ 36.25	$ 92.41	85%	12.41	2.07	2.23	14.20	0.50	27.11
UG1	Utah PC Hunter 4 $20/Ton	$ 1,234	8.50%	$ 104.89	$ 41.37	$ 146.26	85%	19.64	0.95	1.06	10.10	0.48	30.22
WG1	Wyo PC Wyodak 2	$ 1,924	8.50%	$ 163.54	$ 41.37	$ 204.91	85%	27.52	0.42	0.44	4.16	0.48	32.16
WG2	Wyo Coal $6.70/Ton	$ 1,924	8.50%	$ 163.54	$ 41.37	$ 204.91	85%	27.52	0.43	0.45	4.29	0.48	32.29
UCY	Utah IGCC Hunter 4	$ 1,355	8.70%	$ 117.89	$ 40.28	$ 158.17	85%	21.24	0.95	1.06	8.43	2.26	31.93
WCY	Wyo IGCC Wyodak 2	$ 1,845	8.70%	$ 160.52	$ 40.28	$ 200.80	85%	26.97	0.42	0.44	3.48	2.26	32.70
WCZ	Wyo IGCC CT	$ 1,845	8.70%	$ 160.52	$ 40.28	$ 200.80	85%	26.97	0.43	0.45	3.58	2.26	32.81
UG2	Utah Coal $23.25/Ton	$ 1,530	8.50%	$ 130.05	$ 41.37	$ 171.42	85%	23.02	1.11	1.23	11.74	0.48	35.24
UCZ	Utah IGCC CT	$ 1,451	8.70%	$ 126.24	$ 40.28	$ 166.52	85%	22.36	1.11	1.23	9.80	2.26	34.42
UG3	Utah Coal $27.00/Ton	$ 1,530	8.50%	$ 130.05	$ 41.37	$ 171.42	85%	23.02	1.29	1.43	13.63	0.48	37.13
OGT	OWC Geothermal	$ 2,376	9.90%	$ 235.22	$ 18.91	$ 254.13	90%	32.23	1.07	1.07	10.73	2.12	45.08
UGT	Utah Geothermal	$ 2,376	9.90%	$ 235.22	$ 18.91	$ 254.13	90%	32.23	1.07	1.07	10.73	2.12	45.08
UW1	Utah Wind	$ 1,215	10.58%	$ 128.55	$ 70.56	$ 199.11	36%	64.03	-	-	-	-	64.03
WW1	Wyo Wind	$ 1,215	10.58%	$ 128.55	$ 70.56	$ 199.11	36%	64.03	-	-	-	-	64.03
OCT	OWC Simple Cycle CT	$ 390	9.58%	$ 37.36	$ 22.31	$ 59.67	15%	45.41	1.87	2.01	20.81	0.10	66.32
UCT	Utah Simple Cycle CT	$ 461	9.58%	$ 44.12	$ 25.91	$ 70.03	15%	53.30	2.13	2.29	23.68	0.10	77.07
WCT	Wyo Simple Cycle CT	$ 494	9.58%	$ 47.30	$ 26.53	$ 73.83	15%	56.18	2.13	2.29	23.68	0.10	79.96
IET	Idaho Bridger Trans	$ 150	8.50%	$ 12.75	-	$ 12.75	100%	1.46	-	-	-	-	1.46
IEV	Idaho Htr/Id Trans L	$ 150	8.50%	$ 12.75	-	$ 12.75	100%	1.46	-	-	-	-	1.46
OET	OWC Bridger Trans L	$ 300	8.50%	$ 25.50	-	$ 25.50	100%	2.91	-	-	-	-	2.91
UET	Utah Wyo/Ut Tran L	$ 302	8.50%	$ 25.67	-	$ 25.67	100%	2.93	-	-	-	-	2.93
OPS	OWC Pump Storage	$ 816	8.50%	$ 69.36	$ 16.79	$ 86.15	30%	32.78	-	-	-	-	32.78
UPS	Utah Pumped Storage	$ 816	8.50%	$ 69.36	$ 16.79	$ 86.15	30%	32.78	-	-	-	-	32.78
USR	Utah Solar	$ 4,763	10.32%	$ 491.51	$ 19.75	$ 511.26	23%	254.58	-	-	-	3.49	258.07

32.72

22.44

The two pages of Table 4-19 show 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 TRC, as a reasonableness check against model output results.

As with RAMPP-4 and the RAMPP-4 Update, 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.

The next chapter combines these inputs through modeling to arrive at the results for the new RAMPP-5 base case.

Chapter 5: RAMPP-5 Base Case and Comparison to RAMPP-4 Update Base Case

The new RAMPP-5 base case incorporates the two adjustments discussed in the first chapter: 1) in the load forecast, and 2) in the role of wholesale transactions. These modifications to IRP assumptions allow the company to better model the realities affecting utility planning in an increasingly competitive environment.

The load forecast adjustment recognizes the anticipated loss of some of the company's existing regulated load. This load loss will occur as open access begins in more states within the company's service territory. California will begin open access in 1998, followed soon thereafter by Montana. Open access will probably begin in the other states by the year 2000. The company believes that within five years it will lose at least 10 percent of its current regulated retail load. Surveys of customers who have open access choices and surveys of intent by customers who anticipate open access indicate that the loss could be up to 30 or 40 percent. The company does not believe it is reasonable to plan for and build resources for regulated load which it expects to lose within the next five years.

Although the company will undoubtedly gain load from new customers in areas of open access, the company will not have an obligation to serve these new customers due to their ability to choose their supplier. Long-range planning of an IRP style therefore is not necessary for these new customers. The company will certainly engage in long and short-range planning, but it will be for a competitive market.

To recognize the reality of impending regulated load losses, the company has reduced the load forecast used in the model inputs for the new RAMPP-5 base case. Beginning in 1998, each year's load forecast is 2 percent less than the level in the unadjusted forecast. Thus in 1998 the load forecast is 2 percent less, in 1999 it is 4 percent less, etc., until it reaches a 10 percent reduction by the fifth year. Although the company may not begin losing 2 percent a year as early as 1998, the assumption of a 2 percent loss per year, for the first five years, allows for a smooth transition to the anticipated end result of 10 percent loss by the fifth year.

The load forecast used in the new RAMPP-5 base case modeling includes a continuing, but constant 10 percent loss (relative to the unadjusted load forecast) through the remaining years of the planning horizon.

The second key adjustment that the company has made is in the area of wholesale contracts. The issue pertains to long-range contracts of one year or more. The company does not include wholesale sales and purchases of less than one year in anticipating the need for new long-term resource acquisitions. Wholesale sales and purchases of more than one year are part of the load and resource mix that can affect decisions for new long-term resource acquisitions. Because of this, temporary imbalances in wholesale sales versus purchases can have a dramatic impact on perceived load/resource balance and thus on planning.

The new RAMPP-5 base case removes the impact of these temporary imbalances in long-term contracts on planning. The adjustment increases the amount of short-term wholesale purchases made in each of the first five years of the planning horizon to achieve a balance between wholesale sales and wholesale purchases by the fifth year. This scenario closely reflects the company's strategy of relying increasingly on the wholesale market to acquire the resources needed to meet the commitments made in long-term wholesale sales contracts. The adjustment has the effect of removing the impact of wholesale transactions on IRP modeling.

These two adjustments are the first steps in reflecting realistic expectations in the IRP process. The company anticipates that additional adjustments could be necessary as all of the affected parties better understand the implications of a more competitive market for the electric utility industry.

Tables 5-1 and 5-2 show the year-by-year results for the new RAMPP-5 base case. Table 5-1 illustrates the results for summer capacity. Table 5-2 depicts the results for energy. These tables show new resource additions for each year of the first ten years, and then for every fifth year. Therefore, during the second ten years, it is not clear whether the model added new resources in 2008, 2009, 2010, 2011, or 2012. Since the company does not have to make a decision now for the second ten year period, this summary of results should not be a problem.

Table 5-1

RAMPP-5 Base Case
(Including 15% DSM Advantage)
Incremental Summer Capacity (MW) of Resource Additions

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
	Short Term Cap Purch											179.7	508.8
	DSM Programs	6.0	5.8	6.3	6.2	6.3	6.3	6.4	6.4	6.3	6.4	26.1	42.3
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2												425.3
C	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**6.0**	**5.8**	**6.3**	**6.2**	**6.3**	**6.3**	**6.4**	**6.4**	**6.3**	**6.4**	**26.1**	**467.6**
	DSM Programs	0.5	0.5	0.5	0.5	0.6	0.6	0.7	0.6	0.6	0.6	2.4	3.3
I	Idaho Cogen 1												
D	Idaho Cogen 2												
A	Idaho Combined Cycle												
H	Idaho Bridger Trans												
O	Idaho Htr/Id Trans L												
	Total	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.7**	**0.6**	**0.6**	**0.6**	**2.4**	**3.3**
	DSM Programs	11.1	10.7	10.2	10.6	10.8	10.2	10.8	10.3	10.2	10.6	47.5	74.1
	Utah Wind												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle												
	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 Pumped Storage												
	Utah Wyo/Ut Tran L												
	Total	**11.1**	**10.7**	**10.2**	**10.6**	**10.8**	**10.2**	**10.8**	**10.3**	**10.2**	**10.6**	**47.5**	**74.1**
	DSM Programs	1.9	2.0	2.0	2.1	2.2	2.3	2.3	2.3	2.3	2.3	8.7	14.5
W	Wyo Wind												
Y	Wyo Combined Cycle												
O	Wyo IGCC Wyodak 2												
M	Wyo IGCC CT												
I	Wyo PC Wyodak 2												
N	Wyo Coal $6.70/Ton												
G	Wyo Simple Cycle CT												
	Total	**1.9**	**2.0**	**2.0**	**2.1**	**2.2**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**8.7**	**14.5**
T	DSM Programs	19.5	19.0	19.0	19.4	19.9	19.4	20.2	19.6	19.4	19.9	84.7	134.2
O	Short Term Cap Purch											179.7	508.8
T	Cogeneration												425.3
A	Combined Cycle CT												
L	All Others												
	Total	**19.5**	**19.0**	**19.0**	**19.4**	**19.9**	**19.4**	**20.2**	**19.6**	**19.4**	**19.9**	**264.4**	**1,068.3**

Annual Summer Peak Capacity (MW)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
S	Native Load	7,526	7,589	7,659	7,693	7,562	7,705	7,349	8,008	8,162	8,317	9,105	9,938
Y	Long Term Sales	2,593	2,525	2,444	2,091	1,845	1,793	1,393	1,370	1,362	1,112	987	842
S	DSM Programs	(19)	(39)	(57)	(77)	(97)	(116)	(136)	(156)	(175)	(195)	(280)	(414)
T	**Total Requirements**	**10,100**	**10,075**	**10,046**	**9,707**	**9,310**	**9,382**	**9,306**	**9,222**	**9,349**	**9,234**	**9,812**	**10,366**
E													
M	Existing Generation	9,965	10,076	9,934	9,940	9,955	9,862	9,866	9,749	9,753	9,757	9,637	9,627
	Long Term Purchases	1,023	996	992	970	723	707	558	558	558	558	440	418
L	Short Term Market	220	440	660	880	1,122	1,085	1,035	812	805	554	548	423
&	Short Term Cap Purch											180	509
&	New Resources												425
R	**Total Resources**	**11,208**	**11,512**	**11,586**	**11,790**	**11,800**	**11,654**	**11,458**	**11,119**	**11,115**	**10,869**	**10,794**	**11,402**
	Reserves	1,109	1,436	1,541	2,083	2,490	2,274	2,153	1,897	1,767	1,635	981	1,036
	Reserve Margin (%)	11.0	14.3	15.3	21.5	26.8	24.2	23.1	20.6	18.9	17.7	10.0	10.0

Table 5-2

RAMPP-5 Base Case
(Including 15% DSM Advantage)
Cumulative Annual Energy (MWa)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
	DSM Programs	4.4	8.7	13.3	18.0	22.6	27.3	32.1	36.9	41.6	46.4	66.2	98.7
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2												394.3
C	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	4.4	8.7	13.3	18.0	22.6	27.3	32.1	36.9	41.6	46.4	66.2	493.0
	DSM Programs	0.4	0.8	1.2	1.6	2.0	2.5	3.0	3.4	3.9	4.4	6.2	8.8
I	Idaho Cogen 1												
D	Idaho Cogen 2												
A	Idaho Combined Cycle												
H	Idaho Bridger Trans												
O	Idaho Htr/Id Trans L												
	Total	0.4	0.8	1.2	1.6	2.0	2.5	3.0	3.4	3.9	4.4	6.2	8.8
	DSM Programs	7.2	14.1	20.6	27.4	34.3	40.8	47.7	54.4	60.9	67.7	99.0	148.4
	Utah Wind												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle												
	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 Pumped Storage												
	Utah Wyo/Ut Tran L												
	Total	7.2	14.1	20.6	27.4	34.3	40.8	47.7	54.4	60.9	67.7	99.0	148.4
	DSM Programs	1.6	3.1	4.8	6.5	8.2	10.0	11.7	13.5	15.4	17.2	24.1	35.8
W	Wyo Wind												
Y	Wyo Combined Cycle												
O	Wyo IGCC Wyodak 2												
M	Wyo IGCC CT												
I	Wyo PC Wyodak 2												
N	Wyo Coal $6.70/Ton												
G	Wyo Simple Cycle CT												
	Total	1.6	3.1	4.8	6.5	8.2	10.0	11.7	13.5	15.4	17.2	24.1	35.8
	DSM Programs	13.5	26.7	39.9	53.4	67.1	80.5	94.5	108.2	121.8	135.7	195.5	291.7
	Short Term Cap Purch											0.1	0.4
T	Cogeneration												394.3
O	Combined Cycle CT												
T	Coal												
A	Transmission												
L	Simple Cycle												
	Storage												
	Total	13.5	26.7	39.9	53.4	67.1	80.5	94.5	108.2	121.8	135.7	195.6	686.4
S	Native Load	5,501.5	5,544.6	5,591.0	5,625.2	5,530.7	5,644.1	5,755.4	5,869.5	5,985.9	6,112.4	6,719.3	7,375.0
Y	Pump Storage/Peak Return	296.5	293.5	258.5	249.1	235.2	257.6	258.1	242.2	256.6	256.6	256.6	256.6
S	Long Term Sales	2,233.6	2,039.0	1,866.2	1,535.3	1,400.4	1,350.3	1,239.6	1,068.7	1,030.8	907.1	814.7	730.7
T	Short Term Sales	951.2	1,234.4	1,506.9	1,774.3	1,848.8	1,759.4	1,696.2	1,665.1	1,517.6	1,473.2	1,106.2	1,018.1
E	DSM Programs	(13.5)	(26.7)	(39.8)	(53.3)	(67.1)	(80.5)	(94.5)	(108.2)	(121.8)	(135.7)	(195.5)	(291.7)
M	Total Requirements	8,969.3	9,084.9	9,182.7	9,130.6	8,948.1	8,930.8	8,854.8	8,737.3	8,669.1	8,613.6	8,701.3	9,088.6
	Existing Generation	7,[illegible]	7,681.2	7,597.7	7,576.7	7,503.5	7,516.4	7,[illegible]	7,774.9	7,746.1	7,769.9	7,787.8	7,817.7
L	Long Term Purchases	756.6	764.9	756.1	589.2	397.4	395.7	373.6	373.6	373.7	354.8	351.7	317.5
&	Short Term Market	220.0	440.1	660.0	785.4	931.3	908.8	617.7	407.3	403.3	277.9	212.1	212.1
&	Short Term Purchases	334.0	198.8	169.0	179.2	115.9	109.9	170.0	181.5	146.0	210.9	349.5	336.7
R	New Resources											0.1	394.7
	Total Resources	8,969.3	9,084.9	9,182.7	9,130.5	8,948.1	8,930.8	8,854.8	8,737.3	8,669.1	8,613.6	8,701.3	9,[illegible]

The two critical results the company considered were the year for new resource additions, and the amount of cost effective DSM in the action plan period. In 2012 the model began adding resources through short-term capacity purchases. It added 180 MW of short-term capacity purchases in 2012, and larger amounts in subsequent years. This enabled the model to meet its reserve margin requirement in a least-cost way. In 2016 the model began adding resources through cogeneration additions.

DSM additions in the new RAMPP-5 base case amounted to 13.5 MWa in 1998 and an additional 13.5 MWa in 1999. If load loss increases to 30% by 2002 the model selected only 9 MWa of DSM. The model began adding DSM in 1998, not because the system needed additional resources in 1998. Some DSM is cost effective relative to the operating costs of the existing system, and relative to the wholesale market, and because DSM requires a ramp-up period. In order to have an adequate amount of DSM in place in 2012 when the system actually needs it, ramp-up must begin in 1998.

The modeling results for the new RAMPP-5 base case confirm that the major conclusions from RAMPP-4 are still valid: modest amounts of DSM are still cost effective, the deficit year does not require a resource acquisition decision in the next several years, gas-fired resources and purchased power are the least-cost supply-side choices when the system needs additional resources, renewables are not cost effective compared to gas-fired resources, and expanding transmission capacity is not a cost effective choice at this time.

Table 5-3 provides a comparison of these results to the RAMPP-4 Update base case results.

Table 5-3
Total System Inputs 1998 and 2002

Summer MW	1998		2006	
	RAMPP-4 Update Base Case	RAMPP-5 Base Case	RAMPP-4 Update Base Case	RAMPP-5 Base Case
Native Load	7,382	7,526	8,922	8,162
Long-Term Sales	2,648	2,593	1,362	1,362
Cumulative DSM	(21)	(19)	(232)	(175)
Total	10,008	10,100	10,052	9,349
Existing System	9,994	9,965	9,658	9,753
Long-Term Purchases	1,191	1,023	658	558
Short-Term Purchase		220		805
Additions			747	
Total	11,185	11,208	11,058	11,115
Reserve	1,178	1,109	1,005	1,767
Reserve %	11.8%	11.0%	10.0%	18.9%

The results show a 1998 system reserve of 1,178 MW under the RAMPP-4 Update assumptions and a reserve of 1,109 under RAMPP-5 base case assumptions. For 2006 the RAMPP-4 Update reserve was 1,005 MW; for the RAMPP-5 base case it was 1,767 MW. By that point the two RAMPP-5 adjustments (load growth and wholesale transactions) had their impacts fully ramped into system requirements.

At the October 24, 1997, meeting of the RAMPP Advisory Group, several members requested the company perform an additional model run. This run would include all of the updated assumptions for the new RAMPP-5 base case, except for load loss and wholesale balancing. Table 5-4 shows the results for incremental summer capacity of that special sensitivity case. Table 5-5 summarizes the results of the RAMPP-5 base case with this special case.

Table 5 - 4
Base Case with No Load Loss, No Wholesale Balancing
Incremental Summer Capacity (MW) of Resource Additions

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
	Short Term Cap Purch	286.7	351.7	649.1	486.3	381.9	582.7	509.0	499.0	487.3	370.8	614.1	1,000.0
	DSM Programs	6.7	6.6	7.1	7.1	7.0	7.2	7.1	7.1	7.0	7.1	26.0	41.6
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2					84.2		150.3	51.4	162.5		738.1	120.1
C	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**6.7**	**6.6**	**7.1**	**7.1**	**91.2**	**7.2**	**157.4**	**58.5**	**169.5**	**7.1**	**764.1**	**161.7**
	DSM Programs	0.6	0.6	0.6	0.7	0.6	0.7	0.7	0.6	0.7	0.7	2.3	3.2
I	Idaho Cogen 1												
D	Idaho Cogen 2												
A	Idaho Combined Cycle												
H	Idaho Bridger Trans												
O	Idaho Htr/Id Trans L												
	Total	**0.6**	**0.6**	**0.6**	**0.7**	**0.6**	**0.7**	**0.7**	**0.6**	**0.7**	**0.7**	**2.3**	**3.2**
	DSM Programs	13.9	13.3	12.5	13.1	13.2	12.5	13.2	12.7	12.3	13.0	46.9	73.4
	Utah Wind												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												227.0
H	Utah Combined Cycle												
	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 Pumped Storage												
	Utah Wyo/Ut Tran L												
	Total	**13.9**	**13.3**	**12.5**	**13.1**	**13.2**	**12.5**	**13.2**	**12.7**	**12.3**	**13.0**	**46.9**	**300.4**
	DSM Programs	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	9.3	15.5
W	Wyo Wind												
Y	Wyo Combined Cycle												
O	Wyo IGCC Wyodak 2												
M	Wyo IGCC CT												
I	Wyo PC Wyodak 2												
N	Wyo Coal $6.70/Ton												
G	Wyo Simple Cycle CT												
	Total	**2.3**	**2.3**	**2.4**	**2.4**	**2.4**	**2.4**	**2.5**	**2.5**	**2.5**	**2.5**	**9.3**	**15.5**
T	DSM Programs	23.5	22.8	22.6	23.3	23.2	22.8	23.5	22.9	22.5	23.3	84.5	133.7
O	Short Term Cap Purch	286.7	351.7	649.1	486.3	381.9	582.7	509.0	499.0	487.3	370.8	614.1	1,000.0
T	Cogeneration					84.2		150.3	51.4	162.5		738.1	347.1
A	Combined Cycle CT												
L	All Others												
	Total	**310.2**	**374.5**	**671.7**	**509.6**	**489.3**	**605.5**	**682.8**	**573.3**	**672.3**	**394.1**	**1,436.7**	**1,480.8**

Annual Summer Peak Capacity (MW)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
S	Native Load	7,681	7,906	8,148	8,362	8,402	8,561	8,721	8,898	9,069	9,240	10,116	11,042
Y	Long Term Sales	2,593	2,525	2,444	2,091	1,845	1,793	1,593	1,370	1,362	1,112	987	842
S	DSM Programs	(23)	(46)	(69)	(92)	(115)	(138)	(162)	(185)	(207)	(230)	(315)	(449)
T	**Total Requirements**	**10,251**	**10,385**	**10,523**	**10,361**	**10,132**	**10,216**	**10,152**	**10,083**	**10,224**	**10,122**	**10,788**	**11,435**
E													
M	Existing Generation	[illegible]	10,176	9,934	9,940	[illegible]	9,862	9,866	9,749	9,753	9,757	9,627	9,627
	Long Term Purchases	1,024	996	992	970	723	708	558	558	558	558	440	419
L	Short Term Market												

Table 5 - 5
Impact of Removing Major RAMPP-5 Adjustments
Annual Summer Peak Capacity (MW)

RAMPP-5 Base Case

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
S	Native Load	7,526	7,589	7,659	7,693	7,562	7,705	7,849	8,008	8,162	8,317	9,105	9,938
Y	Long Term Sales	2,593	2,525	2,444	2,091	1,845	1,793	1,593	1,370	1,362	1,112	987	842
S	DSM Programs	(19)	(39)	(57)	(77)	(97)	(116)	(136)	(156)	(175)	(195)	(277)	(407)
T	**Total Requirements**	**10,100**	**10,075**	**10,046**	**9,707**	**9,310**	**9,382**	**9,306**	**9,222**	**9,349**	**9,234**	**9,815**	**10,373**
E													
M	Existing Generation	9,965	10,076	9,934	9,940	9,955	9,862	9,866	9,749	9,753	9,757	9,627	9,627
	Long Term Purchases	1,023	996	992	970	723	707	558	558	558	558	440	418
L	Short Term Market	220	440	660	880	1,122	1,085	1,035	812	805	554	548	423
&	Short Term Cap Purch												291
R	New Resources											183	651
	Total Resources	**11,208**	**11,512**	**11,586**	**11,790**	**11,800**	**11,654**	**11,458**	**11,119**	**11,115**	**10,869**	**10,797**	**11,410**
	Reserves	1,109	1,436	1,541	2,083	2,490	2,274	2,153	1,897	1,766	1,635	982	1,037
	Reserve Margin (RM) (%)	11.0	14.3	15.3	21.5	26.8	24.2	23.1	20.6	18.9	17.7	10.0	10.0

No Load Loss and No Wholesale Purchase Adjustments

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
S	Native Load	7,681	7,906	8,148	8,362	8,402	8,561	8,721	8,898	9,069	9,240	10,116	11,042
Y	Long Term Sales	2,593	2,525	2,444	2,091	1,845	1,793	1,593	1,370	1,362	1,112	987	842
S	DSM Programs	(23)	(46)	(69)	(92)	(115)	(138)	(162)	(185)	(207)	(230)	(315)	(449)
T	**Total Requirements**	**10,251**	**10,385**	**10,523**	**10,361**	**10,132**	**10,216**	**10,152**	**10,083**	**10,224**	**10,122**	**10,788**	**11,435**
E													
M	Existing Generation	9,965	10,076	9,934	9,940	9,955	9,862	9,866	9,749	9,753	9,757	9,627	9,627
	Long Term Purchases	1,024	996	992	970	723	708	558	558	558	558	440	419
L	Short Term Market												
&	Short Term Cap Purch	287	352	649	486	382	583	509	499	487	371	614	1,000
R	New Resources					84	84	234	286	449	448	1,187	1,534
	Total Resources	**11,276**	**11,424**	**11,575**	**11,396**	**11,144**	**11,237**	**11,167**	**11,092**	**11,247**	**11,134**	**11,868**	**12,580**
	Reserves	1,025	1,039	1,052	1,036	1,013	1,021	1,015	1,008	1,023	1,012	1,079	1,143
	Reserve Margin (RM) (%)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Difference (Base Case less No Adjustments)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
S	Native Load	(155)	(317)	(489)	(669)	(840)	(856)	(872)	(890)	(907)	(923)	(1,011)	(1,104)
Y	Long Term Sales												
S	DSM Programs	4	7	12	15	18	22	26	29	32	35	38	42
T	**Total Requirements**	**(151)**	**(310)**	**(477)**	**(654)**	**(822)**	**(834)**	**(846)**	**(861)**	**(875)**	**(888)**	**(973)**	**(1,062)**
E													
M	Existing Generation												
	Long Term Purchases	(1)	0	0	0		(1)	(1)	(0)	(1)	(0)	(1)	(1)
L	Short Term Market	220	440	660	880	1,122	1,085	1,035	812	805	554	548	423
&	Short Term Cap Purch	(287)	(352)	(649)	(486)	(382)	(583)	(509)	(499)	(487)	(371)	(614)	(709)
R	New Resources					(84)	(84)	(234)	(286)	(449)	(448)	(1,004)	(883)
	Total Resources	**(68)**	**88**	**11**	**394**	**656**	**417**	**291**	**27**	**(132)**	**(265)**	**(1,071)**	**(1,170)**
	Reserves	84	397	489	1,047	1,477	1,253	1,138	889	743	623	(97)	(106)
	Reserve Margin (RM) (%)	1.0	4.3	5.3	11.5	16.8	14.2	13.1	10.6	8.9	7.7		

The primary impact of removing the two assumptions was to increase the need for new resources. Without them, the system would need 287 MW of short-term capacity purchases in 1998. The model continued making short-term capacity purchases through 2001. Beginning in 2002, it began adding cogeneration. It could not add cogeneration earlier because of lead-time constraints. DSM increased slightly, from 29 MW (13.5 MWa) to 23 MW (16.3 MWa) in 1998.

Table 5-5 summarizes the impact of removing these assumptions. The first section shows the key results from the RAMPP-5 base case. The second section shows the key results from the special sensitivity case. The third section shows the difference between the two. Removing the load loss assumption increases native load, for example from 7,526 MW to 7,681 MW in 1998. By 2002 the change is from 7,562 MW to 8,402 MW of load. Removing the wholesale balancing assumption removes short-term market purchases. The model added short-term capacity purchases to compensate for these two changes in assumptions. In the special sensitivity case, the model compensated for higher loads and for fewer resources (no short-term market purchases) by adding new resources to the system.

The company believes that following the path of these unadjusted results would cause the acquisition of significant amounts of new resources. This is because the company could lose significant amounts of regulated load for which it has an obligation to serve. In addition, the market provides ample opportunities to acquire resources needed for wholesale sale commitments. Acquisition of new resources under these circumstances would not be prudent behavior on the part of a utility facing important, but somewhat unknown changes in the pretenses under which it conducts business. Therefore, the company does not support the results of the unadjusted base case.

The next chapter identifies the action plan appropriate for the results of the sensitivities discussed in Chapter 3, and the results of the new RAMPP-5 base case.

Chapter 6: RAMPP-5 Action Plan

To evaluate the modeling results, the company focused on the first ten years. 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 from now, the company chose not to focus model results on the second ten year period.

The company gave considerably more weight to the results of the new RAMPP-5 base case than it did to the sensitivities performed on the RAMPP-4 Update base case. The RAMPP-5 base case incorporates significant changes in two assumptions: 1) the load growth adjustment, and 2) the wholesale transactions adjustment. Those changes allowed the company to incorporate, in its modeling, a more realistic assessment of current market and industry conditions. The RAMPP-4 Update base case did not include these assumptions.

In evaluating the modeling results, the company focused on two key outcomes:

1) The decision year for new resource acquisitions, and

2) The cost effective amount of DSM for 1998 and 1999.

The company developed the new RAMPP-5 action plan after reviewing the results of the sensitivities and the new RAMPP-5 base case. Since the new RAMPP-5 base case identified DSM as the only cost effective resource activity until 2006, development of the action plan was simplified.

Under the RAMPP-5 base case assumptions, the company does not need new baseload resources until the year 2016. This time frame means the company does not have to make any supply-side resource decisions in the two years covered by the RAMPP-5 action plan (1998 and 1999), nor in the additional two years required by Utah. Peak purchases require less than one year of lead time, requiring a decision for 2012 in 2011. Gas-fired resources have a four year lead time, requiring a decision for 2016 by 2012.

Developing a RAMPP action plan for the next few years, when the company anticipates dramatic changes in the industry and in regulation is very difficult. The company anticipates making decisions, but it cannot anticipate how conditions may change and thus what the best action items may be. Flexibility is the key to success in the changing electric utility industry. The company identifies target ranges of DSM activity for the next two years and other areas for ongoing attention.

The model chose resources based on one criteria, their ability to lower total costs over a 40 year period. This provides useful information to the company, but management makes its resource acquisition decisions on other criteria as well. Management also looks at price impacts, resource operability, fit with the existing system, future uncertainties and risks, and opportunities and conditions at the time. Evaluation of any opportunity typically requires more extensive financial and operational analysis than can be accomplished within RAMPP. RAMPP provides a first step in a careful analysis and the evaluation process the company uses before making an acquisition.

The model added DSM in the next two years (1998 and 1999) because some DSM appears to be cost effective relative to system operating costs and market prices, and because ramp-up constraints required beginning programs now to have a sufficient amount of DSM in place when needed. Therefore, the action plan includes a level of DSM activity sufficient to maintain current programs.

1) **Demand Side Management**: Implement the amount of demand side activity consistent with a competitive utility environment, considering cost and financial and price impacts. Continue with on-going DSM activity, finding the most cost effective areas for investment. Achieve 9 to 13.5 MWa of installed cost effective savings in 1998, and an additional 9 to 13.5 MWa in 1999. Table 6-1 shows these high and low DSM targets for 1998 by sector and state.

Table 6 - 1
DSM (MWa) Selected for 1998 by Sector and State

RAMPP-5	Ore	Wash	Cal	Mont	Ida	Uta	Wyo	Total
<u>High DSM Target</u>								
Total Residential	0.40	0.04	0.00	0.04	0.06	1.17	0.15	**1.86**
Total Commercial	2.12	0.76	0.00	0.15	0.12	5.16	0.54	**8.85**
Total Industrial	0.59	0.24	0.00	0.03	0.18	0.90	0.85	**2.79**
Total	**3.11**	**1.04**	**0.00**	**0.22**	**0.36**	**7.23**	**1.54**	**13.50**
<u>Low DSM Target</u>								
Total Residential	0.11	0.02	0.00	0.02	0.06	0.73	0.15	**1.09**
Total Commercial	1.20	0.43	0.00	0.08	0.08	3.68	0.36	**5.83**
Total Industrial	0.48	0.15	0.00	0.02	0.13	0.67	0.63	**2.08**
Total	**1.79**	**0.60**	**0.00**	**0.12**	**0.27**	**5.08**	**1.14**	**9.00**

In addition to its DSM acquistion activities, the company will continue to support and work with other parties in the development of public funding mechanisms and alternative implementation strategies for DSM and renewable resources.

As in RAMPP-4 and the RAMPP-4 Update, the company based its DSM targets on DSM costs that are 15 percent lower than costs the company actually incurs. The 15 percent reduction reflects the 10 percent Regional Act Credit and an additional 5 percent for avoided investment in transmission and distribution.

The company selected DSM targets in the action plan by reviewing the results of additional model runs that varied the expected load loss due to open access and competition. The model selected 13.5MWa as the cost effective DSM for 1998 assuming a load loss as high as 30 percent by 2002. The company expects actual load loss due to open access and competition to be at least 10 percent by 2002 and more likely higher. Other model output showed a consistent minimum of 9 MWa of DSM as being cost effective for 1998. Therefore, a range of 9 to 13.5 MWa is a reasonable target for annual DSM in the RAMPP-5 action plan. This provides support for ongoing programs.

The company is concerned about its ability to achieve DSM targets because of growing reluctance on the part of industrial customers to implement or pay the up-front capital costs for DSM projects. Due to the globally competitive environment that most companies face, near term competitiveness (vis-a-vis operating costs) take precedence over long-term paybacks associated with energy efficiency projects. With direct access pilots and the market opening in California, customers are clamoring for price reductions in the form of access to open markets rather than remaining concerned about long-term power costs. RAMPP modeling can identify cost effective DSM targets, but fails to include considerations of customer willingness to participate in DSM projects.

Therefore, the achieved DSM may not correlate closely with Table 6-1 in terms of its distribution across states and across sectors. The company will make every effort to achieve the DSM targets identified in this action plan. However, some of the opportunities considered by the RAMPP analysis may turn out to be not cost effective. On the other hand, cost effective opportunities may arise which the RAMPP analysis did not anticipate.

2) **Existing System**: Continue to make cost effective improvements to the existing generation, transmission, and distribution systems.

Although the RAMPP modeling did not separate out specific existing system improvements, the company uses the results of avoided cost calculations to determine the cost effectiveness of investments in the existing system. Whenever an opportunity arises for an investment to improve the system and passes the avoided cost threshold, the company seriously compares it to alternative investment opportunities.

Improving the existing system includes pursuing cost effective opportunities to relieve transmission constraints through distributed generation. The technology of distributed generation is improving in both performance and cost, and the company will continue to evaluate any opportunities that arise for cost effective use of that technology.

The company is actively involved in work with the IndeGO task force, and through that body, it is working on system reliability issues. As the industry moves toward competition, electric system reliability and the adequacy of the existing transmission system will become increasingly important.

3) **Other Opportunities:** Pursue cost effective resource acquisition opportunities that meet the future needs of the company.

   In a changing competitive industry, opportunities can develop which allow the company to improve its competitive position, increase sales at a profitable level, or improve its earnings. PacifiCorp will continue to pursue any such opportunities which enhance services to customers at competitive prices and increase shareholder value.

   One of the opportunity areas that may meet customers' needs is renewables. The company is seeing increased customer interest in purchasing "green" power. Now that construction has begun on the Foote Creek Wind Plant, the company is looking for other opportunities to acquire "green" resources cost effectively. Therefore, the company will continue to evaluate potential wind and geothermal projects. The company's Blundell geothermal provides a valuable learning base. The Foote Creek project and the company's solar PV projects will also provide valuable experience in the area of "green" resources.

Chapter 7: Performance on RAMPP-4 and RAMPP-4 Update Action Plans

In the RAMPP-4 Update Report, the company reported on its performance on the RAMPP-4 action plan during 1996. This chapter will summarize the 1996 performance and discuss the company's 1997 performance on the RAMPP-4 action plan as modified by the RAMPP-4 Update.

In the RAMPP-4 action plan, the company discussed the wisdom of postponing decisions. Events since then have reinforced the benefits of this approach. Finding cost effective alternatives to capital expenditures has been beneficial to customers as the cost of power in the wholesale market remained competitive during 1996 and 1997.

1) **DSM goal from RAMPP-4 and RAMPP-4 Update Action Plans:** Implement 23 MWa of installed cost effective savings for 1996 and 15.7 MWa for 1997. 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. The company modified the DSM targets in the RAMPP-4 Update. The new information included in modeling a RAMPP-4 Update base case indicated that only 15.7 MWa of DSM was cost effective for 1997.

   Performance: The company achieved 24.1 MWa (105 percent) of the 1996 goal of 23 MWa and expects to meet the 1997 goal of 15.7 MWa by the end of 1997. PacifiCorp's DSM achievements have varied across jurisdictions, depending on opportunities and costs in various sectors. Although PacifiCorp has historically met overall goals, state-by-state performance has varied across jurisdictions. In each jurisdiction, PacifiCorp has responded to market opportunities in developing and implementing DSM programs. Depending on the customer receptivity and the specific jurisdiction's interests, cost effective DSM achievements have varied in terms of state level RAMPP goals. Each jurisdiction has a distinctive perspective on DSM, which the company tries to recognize in developing and implementing DSM programs.

a) Identify and pursue opportunities to target DSM to areas that will allow the company to reduce its transmission and distribution costs.

During 1997, 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 possible 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 is 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.

During 1996 and 1997, the company continued to emphasize participant contributions through the Energy Service Charge. The company broadened its emphasis on maximizing participant contributions to maintain stable rates. In the commercial and industrial sectors, the company uses the Energy Service Charge. PacifiCorp provides an energy study and a financing offer. Typically, the customer pays for the measure installation costs, preferring to use their own financing.

The company has also worked at the regional and state levels to pro-actively develop alternative funding sources for DSM, including market transformation initiatives and low-income weatherization. This included participation in the Regional Comprehensive Review and restructuring discussions in Idaho, Oregon, California, Utah, Montana, Washington, and Wyoming. It also included activities to create an alternate funding mechanism for cost effective DSM that is competitively neutral. The company has been an advocate for a non-bypassable public purpose charge to be implemented in conjunction with direct access.

Finally, the company agreed to participate in and fund the Northwest Energy Efficiency Alliance (NEEA) for 1997, 1998, and 1999. The Alliance is a non-profit entity devoted to developing market transformation to increase the efficiency of electric use and reduce market barriers to efficiency improvements made by customers. The Northwest region's investor owned utilities and the Bonneville Power Administration provide its funding. PacifiCorp increased its commitment to the success of the NEEA by committing to fund the Alliance at the $1.5 million level for 1997 and at the $3 million level per year for 1998 and 1999. Efforts underway include energy efficient lighting, horizontal axis washers, industrial motors, and operation and maintenance certification.

2) **Peaking Resources goal from RAMPP-4 and RAMPP-4 Update Action Plans**: The RAMPP-4 action plan recommended that 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 wholesale 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 and 1997, the company purchased on the wholesale market necessary peaking resources. The wholesale market was the least cost choice for peaking needs during that period of time.

3) **Baseload Resources goal from RAMPP-4 and RAMPP-4 Update Action Plans**: 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 action plan called for the company to: 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, and c) continue to evaluate cogeneration and CCCTs with independent developers and pursue agreements or options where cost effective.

   Performance: The company determined that it was unnecessary to make a decision to acquire new baseload resources during 1996 or 1997.

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. Examples from 1996 and 1997 included: the University of Wyoming, the Boise Cascade plant at Wallula, Washington, the James River plant at Camas, Washington, the Pope & Talbot plant in Halsey, Oregon, and the Monsanto plant in Soda Springs, Idaho.

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

   The company continues 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 continues to evaluate cogeneration and CCCTs with independent developers. During 1996 and 1997, the company did not determine that any agreements with independent developers were cost effective.

4) **Existing System goal from RAMPP-4 and RAMPP-4 Update Action Plans**: 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 continues making cost effective improvements to the existing system.

a) Evaluate 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.

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, the company is implementing cost effective projects, such as the steam turbine upgrades at the company's larger units.

b) Continue with cost effective turbine upgrades.

The company will upgrade selected turbine units at coal plants to improve their performance. In 1996, the company gained 15 MW of capacity at Bridger Unit 3 through turbine upgrading; in 1997, it gained 25-30 MW at Bridger Unit 2, 45 MW at Huntington Unit 1, and 30-35 MW at Hunter 2. The cost for these has been in the range of $150 to $250/MW which is considerably less expensive than a new simple cycle CT.

c) Bring 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) Evaluate 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 unit from the infra-structure available at PacifiCorp's Gadsby plant has been in review 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/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 a 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) Continue to implement cost effective transmission and distribution system efficiencies.

The company continues to evaluate 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 and RAMPP-4 Update Action Plans**: 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-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, 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 to evaluate 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 to participate in the Northwest Regional Solar Radiation Data Monitoring Project, and j) continue to support the Oregon State University Wind Research Cooperative.

Performance: During 1996 and 1997, 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.

   Groundbreaking ceremonies for the Wyoming Wind Energy Project occurred September 26, 1997. The 41.4 MW project is located halfway between Rawlins and Laramie, Wyoming, on the Foote Creek Rim, which is among the most windy and energetic sites in the country. It will be the largest wind energy facility in the West (outside of California.) It should be fully operational by late 1998 or early 1999.

   PacifiCorp will own 80 percent of the Foote Creek project, and The Eugene Water & Electric Board (EWEB) will own the balance. The Bonneville Power Administration will purchase 15 MW of the facility's output. The project is being developed by SeaWest Energy out of San Diego, with its partner Tomen Power Corp. The former developer, Kenetech Windpower (KWI), filed for Chapter 11 bankruptcy in May 1996. Since filing for bankruptcy, KWI has attempted to sell their assets to other wind developers.

   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 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 and 1997, 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 most cost effective solutions tend to be equipment upgrades rather than distributed generation.

e) Continue to monitor global climate science.

   The company continues to track scientific developments on climate change and is active in the policy debate concerning international and domestic policy issues related to global climate science.

f) Continue to evaluate 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 (property purchased for preservation and stewardship), UtiliTree (forestry projects including sites in Oregon and California), and methane recovery (to fund capturing methane at a coal mine).

g) Continue to participate in Solar II.

The project began operation on June 5, 1996. It has demonstrated the ability to generate electricity using energy stored in hot salt.

h) Continue to monitor the performance of the company's solar PV projects.

The company continues to monitor the Dangling Rope installation on Utah's Lake Powell and three smaller installations at the High Desert Museum in Bend, Oregon, an elementary school in Green River, Wyoming, and a company office in Moab, Utah.

i) Continue participation in the Northwest Solar Radiation Data Monitoring Project.

PacifiCorp provided financial resources for the project, which developed high quality data on solar sites around the Northwest.

j) Continue to support the OSU Wind Research Cooperative.

The Research Cooperative uses financial resources of its members to purchase equipment, collect data from stations, and analyze the data.

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

Performance: During 1996 and 1997 PacifiCorp monitored industry activities regarding clean coal technologies. Most of the activity centered on (IGCC) technology developments in this country and abroad.

7) **Other Opportunities goal from RAMPP-4 and RAMPP-4 Update Action Plans**: 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 continually seeks out and evaluates transactions and strategic alliances with other utilities and market entities that will bring value to customers and shareholders. Industry analysts predict that there will continue to be a consolidation of players in the electric industry. PacifiCorp continues to search for ways to blend the requirements of its system in complementary ways with systems of other entities through beneficial transactions. These transactions bring use of cost effective resources and services to PacifiCorp's system, while providing advantageous services to the strategic alliance partners.

Examples of the resource acquisition/strategic alliances from the 1996 to 1997 period include:

- Implementation of the transaction with Clark County PUD for Storage and Integration Services,
- Deseret Generation & Transmission Resource Management Transaction,
- Los Angeles Department of Water and Power (LADWP) Transaction for 250 MW Sale/Purchase,
- Formation of **en·able** through an alliance with KN Energy and the development of the Simple Choice product line for PacifiCorp's customers and the customers of other utilities,
- Acquisition of TPC in March 1997.

Clark County PUD

The company and Clark County PUD implemented their contract to provide control area services and dispatch of Clark's resources in 1997. As of August 1, 1997, Clark County had become part of PacifiCorp's control area, and began receiving all of the associated ancillary services. In September 1997, their River Road CCCT went on-line; PacifiCorp dispatches it on behalf of Clark County. To the extent that Clark County does not have use of the output of the plant, PacifiCorp will store the energy for use in Clark County's system when the resource is of greater value to Clark County. This allows Clark County to keep the plant at optimum running levels. While the two parties signed this contract in 1995 and modified it in 1996, it is only now being implemented and bringing benefits to Clark County and PacifiCorp.

Deseret Generation & Transmission Resource Management Agreement

Deseret Generation & Transmission (DG&T) is an electric cooperative based in Sandy Utah serving 36,000 customers and six distribution cooperatives in Arizona, Colorado, Nevada, Utah, and Wyoming. The DG&T transaction signed in 1996 provides resource management services for Deseret. These services include scheduling to manage all of Deseret's member loads, provides an annual firm surplus sale of resources to PacifiCorp, as well as a sale of non-firm surplus to PacifiCorp. In addition, PacifiCorp may utilize Deseret's portion of the Hunter 2 plant during light load hours. PacifiCorp will market these resources on behalf of Deseret and share in the proceeds from the sales. As part of the scheduling services, PacifiCorp also provides billing and accounting services for the loads and resources.

LADWP Sale/Purchase Transaction

PacifiCorp was able to purchase a sizable on-peak resource from the Los Angeles Department of Water and Power (LADWP) for its system during the winter months and sell resources to LADWP in the summer months. This allows both systems to benefit from resources when peak resources are of benefit. The transaction was also unique due to its link to the NYMEX future market for determining prices.

Simple Choice/**en**·able

While not a generation resource, the Simple Choice product line offered now to customers of PacifiCorp and other utilities provides yet another example of how additional value is being brought to PacifiCorp's customers through the benefits of a strategic alliance. The formation of **en**·able through an innovative alliance with KN Energy brings customers access to a variety of branded products and services that local utilities can offer to their customers. These services will be available in one convenient package on one bill served through one service number.

Partnerships and alliances have also been established with DISH Network™, a satellite entertainment company; Metricom's Ricochet™ wireless modem and Internet service; Frontier HomeSaver℠ Long

Distance service; MaxServ, which provides home product repair; and DQE WeatherWise™, for "weatherproofing" customers' energy bills.

TPC Acquisition

TPC is a natural gas gathering, processing, storage, and marketing company that PacifiCorp purchased in March 1997. TPC was formed in 1984 and sold electric power to local cooperatives. TPC built gathering lines over the next two years to collect and bring natural gas to central processing plants. By 1997, TPC had operations in Texas, Louisiana, and Tennessee as well as plans to develop in Pennsylvania, Mississippi, and Michigan. TPC is the largest independent natural gas gatherer and processor in the Gulf of Mexico area and is a leader in gas storage technology and natural gas marketing. TPC's other core businesses are natural gas marketing on an un-bundled basis to utilities in the Midwest, mid-Atlantic, Ohio Valley, and Northeast regions of the U.S.

The addition of TPC to PacifiCorp brings additional fuels expertise in the gas markets to leverage off of in developing market resources or fuel supply alternatives in the West and nationally. While TPC's markets have traditionally been outside the West, the skills and experience of the human resources within TPC are transferable to other markets.

PacifiCorp's General Market Expertise

Strength in domestic wholesale markets is an important part of the company's operations. PacifiCorp is one of the primary bulk power traders in the West and is presently building this capability nationally. During 1996, Pacific Power Marketing (PPM) sold over 400,000 MWh. During 1997, the sales in the Eastern markets are approximately 25,000,000 MWh. Purchasing activities have grown from over 28,000,000 MWh in 1996 to a projected 51,000,000 MWh in 1997.

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

   Performance: PacifiCorp has continued on a strong course of strategic alliances, competitive products, and other activities to fulfill this action plan item. Some of the entities that PacifiCorp has transacted with include the following: Clark County PUD, Eugene

Water & Electric Board, Springfield Public Utilities, Okanogan PUD, Plains Electric Generation & Transmission Cooperative, Municipal Energy Association of Nebraska, San Diego Gas & Electric (Enova Corporation) Kaiser Aluminum, BHP Corporation through Cowlitz PUD, Tillamook PUD, Utah Municipal Power Agency, Salt River Project, the City of Redding and various other California municipalities, Nevada Power Company, and the Western Area Power Administration.

The sales transactions are of varying terms and conditions and are located throughout the Western States Coordinating Council (WSCC.) PacifiCorp continues to have a strong market presence throughout the WSCC. The transactions vary in size from as small as a few MWs to up to 250 MW and provide a variety of services as well as sales of pure commodity. Common to all transactions is an energy solution that brings value and benefits to all parties involved.

The company allied with ABB to form EnergyPact in May 1997. EnergyPact offers help to investor and publicly-owned utilities and energy companies. EnergyPact's products include upgrading generating plant equipment, plant management services, fuel procurement, risk management, and energy trading. EnergyPact brings products and services primarily to wholesale customers outside the WSCC.

PacifiCorp and Northwest Natural Gas announced the formation of an alliance to jointly market gas and energy services and, as the market opens, to offer electric commodities to commercial and industrial customers in Oregon and Washington. The alliance was formed to meet the multiple fuel needs of commercial and industrial customers. Through the alliance, PacifiCorp and Northwest Natural will market gas, electricity, and energy services within as well as outside of their franchised service areas.

9) **IRP goal from RAMPP-4 and RAMPP-4 Update Action Plans:** 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, and 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 worked in 1996 and 1997 to improve the RAMPP process and make it a more effective tool.

a) Implement feasible process improvements identified in the RAMPP-4 regulatory acknowledgment review.

   The second chapter of this report on Regulatory Requirements reviews the improvements required by the acknowledgment orders and the company's response.

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 relate to potential changes to transmission paths. The company included in the RAMPP-4 Update Report, the sensitivities, and the RAMPP-5 base case a stepped function for transmission availability. This stepped function assumed that the contract amount of capacity was available on each path and that an additional amount would be available at a price consistent with existing contracts.

d) Work with regulatory agencies and other parties to modify IRP to make the process more valuable to utilities and their customers.

   The company continues to encourage regulators to apply flexibility in reviewing IRP filings and requirements.

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RESOURCE AND MARKET PLANNING PROGRAM

RAMPP - 5

APPENDIX: MODEL OUTPUT

DECEMBER - 1997

PacifiCorp

Integrated Resource Planning

Load Forecast

RAMPP 5

June 2, 1997

Response to Questions From RAG Meeting on Load Forecast

The following are responses to questions asked at the last RAG meeting and an explanation of changes to the forecast that have occurred since that meeting.

Hospitals And Other Health Services Growth Rates

At the last RAG meeting the question was asked why the commercial sector growth rate for Hospitals was so much higher than Other Health Services?

The commercial sector is separated into twelve different groups which are called Vertical Market Segments (VMS). Each group is divided into existing and new structures. The commercial sector model calculates MWH usage of existing and new structures in each VMS group. MWH usage is determined by multiplying "use per square foot (of each end use appliance)" times "total number of square feet (for each structure type)" times "saturation rate". In RAMPP III the "use per square foot" values for Other Health Services were the same as New Hospitals and produced similar MWH consumption growth rates for both VMS groups. In RAMPP V the "use per square foot" values for New Hospitals are approximately twice the size of "use per square foot" values for Other Health Services and cause significantly different energy consumption growth rates between the two groups.

The decision to use different "use per square foot" values for the two groups in RAMPP V was based on Demand Side Appendix (page 18) for RAMPP III which specifically states that Construction, Transportation, Utility, Services, and Other Health categories were treated as small office buildings and combined with the Office category.

Adjustments to the Model

Three adjustments were made to the model. First, the residential, commercial, and industrial sectors were calibrated to expected energy consumption values for the years 1997 to 2001. In some cases within the residential and commercial sectors this raised the consumption estimates for those years but the amount of the increase was relatively small. Calibration for the industrial sector caused an increase in consumption that was somewhat larger. For each sector the affects of calibrations were carried forward through subsequent forecasting year.

Second, a processing error was discovered in the residential sector of the forecast presented at the April RAG meeting. This error underestimated that true amount of residential energy consumption. The processing error was corrected and improved the residential forecast estimate.

Last, the average annual electricity price escalation rate was adjusted downward to 3.3% for the residential, commercial, and industrial sectors to maintain consistency with the escalation rate used in RAMPP IV Update. This adjustment increased both consumption growth rates and the amount of MWH consumption for each of the sectors. Comparisons of electric price escalation and MWH consumption growth rates before and after the adjustments are shown in Tables I and II respectively.

Table I

Electric Price Escalation Rate Comparison

Sector	Before	After
Residential	4.0%	3.3%
Commercial	3.7%	3.3%
Industrial	4.2%	3.3%

Table II

MWH Consumption Growth Rate Comparison

Sector	Before	After
Residential	1.8%	2.1%
Commercial	2.3%	2.3%
Industrial	1.6%	1.7%

PacifiCorp
Model Peak & Energy
By IPM Resource Bubble

Summer Coincident Peak (MW)							Interruptible		
Year	Month	OWC	Utah	Idaho	Wyoming	Total	Utah	Idaho	Total
1998	7	3,230	3,176	437	838	7,681	186	155	8,022
1999	7	3,313	3,297	441	855	7,906	186	155	8,247
2000	7	3,365	3,467	447	869	8,148	181	155	8,484
2001	7	3,441	3,587	451	883	8,362	181	155	8,698
2002	7	3,513	3,538	460	891	8,402	181	155	8,738
2003	7	3,595	3,590	468	908	8,561	181	155	8,897
2004	7	3,707	3,624	473	917	8,721	186	155	9,062
2005	7	3,777	3,706	482	933	8,898	186	155	9,239
2006	7	3,851	3,776	489	953	9,069	186	155	9,410
2007	7	3,893	3,874	501	972	9,240	181	155	9,576
2008	7	3,925	3,791	506	981	9,203	182	155	9,540
2009	7	4,034	4,030	518	1,007	9,589	181	155	9,925
2010	7	4,097	4,109	526	1,024	9,756	181	155	10,092
2011	7	4,209	4,154	533	1,039	9,935	186	155	10,276
2012	7	4,243	4,265	546	1,062	10,116	181	155	10,452
2013	7	4,356	4,322	551	1,078	10,307	186	155	10,648
2014	7	4,428	4,392	561	1,098	10,479	186	155	10,820
2015	7	4,500	4,470	570	1,120	10,660	186	155	11,001
2016	7	4,534	4,576	585	1,141	10,836	181	155	11,172
2017	7	4,663	4,632	590	1,157	11,042	186	155	11,383

Winter Coincident Peak (MW)							Interruptible		
Year	Month	OWC	Utah	Idaho	Wyoming	Total	Utah	Idaho	Total
1998	1	4,023	2,629	217	841	7,710	163	111	7,985
1999	1	4,122	2,725	220	866	7,933	165	111	8,209
2000	1	4,218	2,841	224	868	8,151	165	111	8,427
2001	1	4,310	2,947	228	890	8,375	165	111	8,651
2002	1	4,385	2,854	232	891	8,362	164	100	8,626
2003	1	4,491	2,931	239	904	8,565	165	111	8,841
2004	1	4,584	2,987	244	916	8,731	165	111	9,007
2005	1	4,671	3,045	251	931	8,898	165	111	9,174
2006	1	4,764	3,107	258	948	9,077	165	111	9,353
2007	1	4,855	3,175	266	964	9,260	165	111	9,536
2008	1	4,953	3,240	272	979	9,444	165	111	9,720
2009	1	5,029	3,306	279	995	9,609	165	111	9,885
2010	1	5,115	3,372	286	1,009	9,782	165	111	10,058
2011	1	5,210	3,439	296	1,030	9,975	165	111	10,251
2012	1	5,312	3,503	304	1,046	10,165	165	111	10,441
2013	1	5,412	3,568	314	1,068	10,362	165	111	10,638
2014	1	5,507	3,631	322	1,084	10,544	165	111	10,820
2015	1	5,605	3,698	332	1,104	10,739	165	111	11,015
2016	1	5,706	3,765	341	1,123	10,935	165	111	11,211
2017	1	5,820	3,836	351	1,142	11,149	165	111	11,425

PacifiCorp
Model Peak & Energy
By IPM Resource Bubble

Annual Energy (GWH)							Interruptible		
Year		OWC	Utah	Idaho	Wyoming	Total	Utah	Idaho	Total
1998		22,084	18,580	1,878	6,635	49,177	1,490	1,273	51,940
1999		22,635	19,307	1,904	6,749	50,595	1,490	1,273	53,358
2000		23,190	20,131	1,941	6,840	52,103	1,490	1,273	54,866
2001		23,715	20,923	1,975	6,949	53,562	1,490	1,273	56,325
2002		24,210	20,582	2,026	7,016	53,833	1,490	1,273	56,596
2003		24,769	20,954	2,077	7,137	54,937	1,490	1,273	57,700
2004		25,310	21,351	2,127	7,231	56,019	1,490	1,273	58,782
2005		25,812	21,780	2,179	7,358	57,130	1,490	1,273	59,893
2006		26,309	22,232	2,235	7,487	58,263	1,490	1,273	61,026
2007		26,842	22,740	2,295	7,618	59,495	1,490	1,273	62,258
2008		27,342	23,222	2,349	7,750	60,663	1,490	1,273	63,426
2009		27,811	23,714	2,404	7,883	61,811	1,490	1,273	64,574
2010		28,281	24,211	2,459	8,003	62,954	1,490	1,273	65,717
2011		28,795	24,707	2,524	8,150	64,175	1,490	1,273	66,938
2012		29,314	25,200	2,591	8,297	65,401	1,490	1,273	68,164
2013		29,829	25,692	2,661	8,444	66,627	1,490	1,273	69,390
2014		30,342	26,159	2,726	8,593	67,820	1,490	1,273	70,583
2015		30,862	26,631	2,794	8,749	69,036	1,490	1,273	71,799
2016		31,400	27,133	2,864	8,899	70,295	1,490	1,273	73,058
2017		32,050	27,723	2,944	9,065	71,783	1,490	1,273	74,546

Annual Energy (MWa)							Interruptible		
Year		OWC	Utah	Idaho	Wyoming	Total	Utah	Idaho	Total
1998		2,521	2,121	214	757	5,614	170	145	5,929
1999		2,584	2,204	217	770	5,776	170	145	6,091
2000		2,647	2,298	222	781	5,948	170	145	6,263
2001		2,707	2,388	225	793	6,114	170	145	6,430
2002		2,764	2,349	231	801	6,145	170	145	6,461
2003		2,828	2,392	237	815	6,271	170	145	6,587
2004		2,889	2,437	243	826	6,395	170	145	6,710
2005		2,947	2,486	249	840	6,522	170	145	6,837
2006		3,003	2,538	255	855	6,651	170	145	6,966
2007		3,064	2,596	262	870	6,792	170	145	7,107
2008		3,121	2,651	268	885	6,925	170	145	7,240
2009		3,175	2,707	274	900	7,056	170	145	7,371
2010		3,228	2,764	281	914	7,187	170	145	7,502
2011		3,287	2,820	288	930	7,326	170	145	7,641
2012		3,346	2,877	296	947	7,466	170	145	7,781
2013		3,405	2,933	304	964	7,606	170	145	7,921
2014		3,464	2,986	311	981	7,742	170	145	8,057
2015		3,523	3,040	319	999	7,881	170	145	8,196
2016		3,584	3,097	327	1,016	8,025	170	145	8,340
2017		3,659	3,165	336	1,035	8,194	170	145	8,510

Appendix: Model Output

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Note: The cases were not numbered in sequence. Therefore, there is no Case #2, #3, etc.

RAMPP-4 Update Base Case
(Including 15% DSM Advantage)
Incremental Summer Capacity (MW) of Resource Additions

		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
	OWC Geothermal													
O	OWC Cogen 1													123.7
W	OWC Cogen 2						189.0	196.1	118.1		122.1	274.1	351.9	55.3
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	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**
	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
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	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													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													377.2
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	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 IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	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

RAMPP-4 Update Base Case
(Including 15% DSM Advantage)
Cumulative Annual Energy (MWa)

		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 Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	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**
	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
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	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 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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	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 IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	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**
	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
	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
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	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**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.3	984.0	1,103.0	1,155.7	1,197.6	1,247.5	1,297.7	1,276.6	1,344.5	1,291.2	1,298.7	1,212.5	1,228.4
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(64.6)	(81.8)	(99.7)	(117.6)	(136.4)	(155.8)	(186.5)	(238.7)	(301.3)	(381.7)
M	**Total Requirements**	8,986.8	9,017.8	8,963.3	8,892.1	8,803.9	8,845.7	9,001.3	9,030.7	9,032.2	9,045.2	9,294.7	9,494.7	9,863.4
	Existing Generation	7,774.0	7,713.8	7,661.8	7,605.0	7,742.1	7,808.0	7,821.7	7,762.0	7,761.4	7,689.2	7,705.1	7,600.9	7,519.0
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.4	334.0	336.5	323.4	349.1	357.7	349.2	352.1	354.3	357.8	376.8	384.5	379.8
R	**New Resources**						183.9	344.8	450.6	450.6	532.3	765.7	1,065.4	1,556.0
	Total Resources	8,986.8	9,017.8	8,963.2	8,892.1	8,803.9	8,845.7	9,001.3	9,030.6	9,032.2	9,045.2	9,294.7	9,494.7	9,863.4

RAMPP-4 Update Base Case
(Including 15% DSM Advantage)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	31	48	65	82	100	118	136	156	187	239	301	382
			After Conservation													
			System Load (MWa)	5,710	5,761	5,856	5,992	6,097	6,222	6,359	6,520	6,616	6,720	7,126	7,519	7,916
	0.65		Energy Sales (MWa)	5,159	5,256	5,355	5,465	5,577	5,692	5,809	5,918	5,990	6,043	6,354	6,683	7,069
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,178	8,403	8,644	8,961	9,265	9,505	9,729	9,995	10,204	11,280	12,410	14,490
			Net Conservation Assets ($M)	16	32	48	63	77	90	102	115	128	144	185	219	259
			Utility Cost													
45,827	3.23	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,282	2,358	2,450	2,451	2,549	2,681	2,798	2,940	3,278	3,793	4,399
	0.23	Real		2,146	2,126	2,151	2,158	2,177	2,115	2,135	2,180	2,209	2,253	2,299	2,435	2,509
	2.57	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.3	50.2	49.2	50.1	51.7	53.3	55.5	58.9	64.8	71.0
	-0.42	Real		47.5	46.2	45.9	45.1	44.6	42.4	42.0	42.1	42.1	42.6	41.3	41.6	40.5
		Nominal	Average Customer Bill ($)	1,602	1,614	1,654	1,678	1,716	1,689	1,727	1,786	1,835	1,899	2,021	2,244	2,450
		Real		1,602	1,567	1,559	1,536	1,524	1,457	1,446	1,453	1,449	1,456	1,418	1,441	1,397
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.0	-43.5	-75.5	-130.0
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-19.1	-37.6	-78.7
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.9	27.7	33.3
45,304	3.134	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,287	2,364	2,458	2,460	2,559	2,692	2,808	2,950	3,282	3,783	4,354
	0.13	Real		2,147	2,129	2,155	2,163	2,184	2,122	2,143	2,189	2,217	2,261	2,302	2,428	2,483
	2.36	Nominal	Cost in mills/kWh	47.4	47.4	48.4	48.9	49.6	48.6	49.4	50.9	52.3	54.2	57.0	62.1	67.0
	-0.62	Real		47.4	46.0	45.6	44.7	44.1	41.9	41.3	41.3	41.3	41.5	40.0	39.8	38.2

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.83**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.95**

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RAMPP-4 Update Base Case (Including 15% DSM Advantage)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,022	50,476	51,288	52,052	52,969	54,065	55,266	56,677	57,500	58,412	61,966	65,414	68,888
	MWa	5,710	5,762	5,855	5,942	6,047	6,172	6,309	6,470	6,564	6,668	7,074	7,467	7,864
	Total Annual Emissions (1000 Tons)													
0.58%	CO2	56,584	56,898	56,930	57,409	57,469	57,086	57,608	57,838	58,177	58,885	60,286	62,336	63,164
-0.05%	NOx	132.6	131.7	130.4	130.2	132.2	132.6	132.8	131.6	131.6	131.8	132.1	132.7	131.3
0.06%	TSP	11.8	11.7	11.7	11.7	11.8	11.8	11.8	11.8	11.8	11.9	11.9	12.0	11.9
	Annual System Emission Rates (Pounds/MWh)													
-1.10%	CO2	2,262	2,254	2,220	2,206	2,170	2,112	2,085	2,041	2,024	2,016	1,946	1,906	1,834
-1.72%	NOx	5.30	5.22	5.09	5.00	4.99	4.90	4.80	4.64	4.58	4.51	4.26	4.06	3.81
-1.61%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.41	0.38	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.13	97.50	95.91	93.34	92.15	90.21	89.44	89.12	86.01	84.24	81.06
	NOx	100	98.42	95.95	94.39	94.15	92.51	90.64	87.62	86.35	85.13	80.41	76.56	71.94
	TSP	100	98.60	96.58	95.40	94.39	92.52	90.66	88.23	87.14	86.11	81.50	77.70	73.41

20 Year Emissions (1000 Tons)	Average	Total
CO2	59,536	1,190,717
NOx	132	2,638
TSP	12	237

No DSM

Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				111.2				59.0		206.0	346.6	500.0	500.0
	DSM Programs													
	OWC Geothermal													
O	OWC Cogen 1													202.1
W	OWC Cogen 2						285.6	216.2	211.4		106.7	317.6	169.1	
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT												140.4	
	OWC Pump Storage													
	Total						**285.6**	**216.2**	**211.4**		**106.7**	**317.6**	**309.5**	**202.1**
	DSM Programs													
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total													
	DSM Programs													
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2												228.8	494.3
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total												**228.8**	**494.3**
	DSM Programs													
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total													
T	DSM Programs													
O	Short Term Cap Purch				111.2				59.0		206.0	346.6	500.0	500.0
T	Cogeneration						285.6	216.2	211.4		106.7	317.6	397.9	696.4
A	Combined Cycle CT													
L	All Others												140.4	
	Total				**111.2**		**285.6**	**216.2**	**270.4**		**312.7**	**664.2**	**1,038.3**	**1,196.4**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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													
T	**Total Requirements**	**9,895**	**10,051**	**9,924**	**10,066**	**9,873**	**9,945**	**10,129**	**10,178**	**10,128**	**10,306**	**10,688**	**11,191**	**11,805**
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				111				59		206	347	500	500
&	New Resources						286	502	713	713	820	1,137	1,676	2,372
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**11,073**	**10,948**	**10,964**	**11,165**	**11,196**	**11,141**	**11,337**	**11,757**	**12,311**	**12,986**

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
Reserves	1,201	1,135	1,207	1,007	1,075	1,019	1,035	1,018	1,013	1,031	1,069	1,119	1,180
Reserve Margin (RM) (%	12.1	11.3	12.2	10.0	10.9	10.2	10.2	10.0	10.0	10.0	10.0	10.0	10.0

No DSM

Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs													
	OWC Geothermal													
O	OWC Cogen 1													200.1
W	OWC Cogen 2						277.6	449.3	638.6	638.6	697.8	968.1	1,112.0	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT												77.0	32.9
	OWC Pump Storage													
	Total						**277.6**	**449.3**	**638.6**	**638.6**	**697.8**	**968.1**	**1,189.0**	**1,345.1**
	DSM Programs													
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total													
	DSM Programs													
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2												194.7	615.4
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total												**194.7**	**615.4**
	DSM Programs													
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total													
	DSM Programs													
	Short Term Cap Purch				0.1				0.1		0.2	0.4	0.5	0.5
T	Cogeneration						277.6	449.3	638.6	638.6	697.8	968.1	1,306.7	1,927.5
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle												77.0	32.9
	Storage													
	Total				**0.1**		**277.6**	**449.3**	**638.6**	**638.6**	**698.0**	**968.4**	**1,384.2**	**1,960.9**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	876.7	973.6	1,085.7	1,126.5	1,152.3	1,239.0	1,284.2	1,311.0	1,346.3	1,279.1	1,290.2	1,232.6	1,238.5
E	**DSM Programs**													
M	**Total Requirements**	8,996.9	9,038.7	8,993.6	8,927.4	8,840.4	8,936.9	9,105.4	9,201.6	9,189.8	9,219.6	9,525.0	9,816.1	10,255.2
	Existing Generation	7,780.8	7,734.2	7,692.6	7,627.4	7,768.4	7,805.3	7,824.2	7,744.2	7,742.3	7,695.4	7,719.1	7,603.2	7,508.6
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	346.7	334.5	336.0	336.2	359.3	358.0	346.4	352.9	343.1	360.4	390.4	384.9	377.1
R	**New Resources**				0.1		277.6	449.3	638.6	638.6	698.0	968.4	1,384.2	1,960.9
	Total Resources	8,996.9	9,038.7	8,993.6	8,927.4	8,840.4	8,936.9	9,105.4	9,201.6	9,189.8	9,219.6	9,525.0	9,816.1	10,255.2

No DSM

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	0	0	0	0	0	0	0	0	0	0	0	0	0
			After Conservation													
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
	0.75		Energy Sales (MWa)	5,173	5,285	5,398	5,524	5,651	5,783	5,916	6,042	6,132	6,213	6,572	6,958	7,417
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	7,996	8,146	8,366	8,620	8,979	9,311	9,581	9,781	10,027	10,210	11,282	12,517	14,781
			Net Conservation Assets ($M)	0	0	0	0	0	0	0	0	0	0	0	0	0
			Utility Cost													
46,723	3.29	Nominal	**Operating Revenues ($M)**	2,147	2,192	2,285	2,377	2,457	2,460	2,571	2,706	2,838	3,002	3,346	3,863	4,514
	0.28	Real		2,147	2,128	2,154	2,175	2,183	2,122	2,153	2,200	2,241	2,301	2,347	2,479	2,574
	2.52	Nominal	Cost in mills/kWh	47.4	47.4	48.3	49.1	49.6	48.6	49.6	51.1	52.8	55.2	58.1	63.4	69.5
	-0.47	Real		47.4	46.0	45.6	45.0	44.1	41.9	41.6	41.6	41.7	42.3	40.8	40.7	39.6
		Nominal	Average Customer Bill ($)	1,603	1,615	1,656	1,692	1,721	1,694	1,742	1,803	1,862	1,939	2,063	2,285	2,514
		Real		1,603	1,568	1,561	1,548	1,529	1,462	1,459	1,466	1,470	1,486	1,447	1,467	1,434
			Total Resource Cost													
			DSR Customer Cost ($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	0.0
			Levelized (20-year at 7.9%)	0.0	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 ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46,723	3.29	Nominal	**Total Resource Cost ($M)**	2,147	2,192	2,285	2,377	2,457	2,460	2,571	2,706	2,838	3,002	3,346	3,863	4,514
	0.28	Real		2,147	2,128	2,154	2,175	2,183	2,122	2,153	2,200	2,241	2,301	2,347	2,479	2,574
	2.52	Nominal	Cost in mills/kWh	47.4	47.4	48.3	49.1	49.6	48.6	49.6	51.1	52.8	55.2	58.1	63.4	69.5
	-0.47	Real		47.4	46.0	45.6	45.0	44.1	41.9	41.5	41.6	41.7	42.3	40.8	40.7	39.6

Notes:

1) $M = millions of dollars 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.20**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.20**

No DSM

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,159	50,750	51,705	52,617	53,686	54,938	56,296	57,874	58,864	60,046	64,058	68,054	72,233
	MWa	5,726	5,793	5,902	6,007	6,129	6,271	6,427	6,607	6,720	6,855	7,313	7,769	8,246
	Total Annual Emissions (1000 Tons)													
0.68%	CO2	56,685	57,141	57,295	57,794	57,942	57,420	58,033	58,195	58,578	59,576	61,224	63,616	64,465
-0.05%	NOx	132.7	132.1	131.1	130.7	132.7	132.5	132.8	131.3	131.2	132.0	132.5	133.4	131.5
0.07%	TSP	11.8	11.8	11.7	11.8	11.8	11.8	11.8	11.8	11.8	11.9	12.0	12.0	12.0
	Annual System Emission Rates (Pounds/MWh)													
-1.23%	CO2	2,260	2,252	2,216	2,197	2,159	2,090	2,062	2,011	1,990	1,984	1,912	1,870	1,785
-1.95%	NOx	5.29	5.21	5.07	4.97	4.95	4.83	4.72	4.54	4.46	4.40	4.14	3.92	3.64
-1.83%	TSP	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.40	0.40	0.37	0.35	0.33
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.63	98.05	97.19	95.50	92.48	91.22	88.98	88.06	87.79	84.57	82.72	78.97
	NOx	100	98.37	95.81	93.88	93.45	91.18	89.19	85.76	84.26	83.07	78.15	74.06	68.78
	TSP	100	98.60	96.26	94.97	93.68	91.39	89.34	86.78	85.15	84.31	79.42	75.04	70.35

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,286	1,205,727
NOx	132	2,644
TSP	12	238

Environmental Adder of $10 /Ton CO2
$ 1,000 /Ton NOx and $ 1,250 /Ton TSP
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				3.7									
	DSM Programs	7.6	7.8	7.8	8.0	8.2	8.3	8.3	8.7	8.9	13.4	22.3	26.3	33.0
	OWC Geothermal													
O	OWC Cogen 1					150.4	51.7							
W	OWC Cogen 2					441.8	441.8	423.0						
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**7.6**	**7.8**	**7.8**	**8.0**	**600.4**	**501.8**	**431.3**	**8.7**	**8.9**	**13.4**	**22.3**	**26.3**	**33.0**
	DSM Programs	0.7	0.6	0.6	0.6	0.7	0.6	0.7	0.6	0.7	1.0	1.7	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.7**	**0.6**	**0.6**	**0.6**	**0.7**	**0.6**	**0.7**	**0.6**	**0.7**	**1.0**	**1.7**	**1.9**	**2.4**
	DSM Programs	12.4	12.1	12.9	13.7	13.3	14.2	14.1	14.3	14.9	23.0	40.7	49.4	63.9
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2					201.9								561.5
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**12.4**	**12.1**	**12.9**	**13.7**	**215.2**	**14.2**	**14.1**	**14.3**	**14.9**	**23.0**	**40.7**	**49.4**	**625.4**
	DSM Programs	3.2	3.2	3.3	3.2	3.4	3.4	3.4	3.4	3.5	5.2	8.4	9.6	12.0
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**3.2**	**3.2**	**3.3**	**3.2**	**3.4**	**3.4**	**3.4**	**3.4**	**3.5**	**5.2**	**8.4**	**9.6**	**12.0**
T	DSM Programs	23.9	23.7	24.6	25.5	25.6	26.5	26.5	27.0	28.0	42.6	73.1	87.2	111.3
O	Short Term Cap Purch				3.7									
T	Cogeneration					794.1	493.5	423.0						561.5
A	Combined Cycle CT													
L	All Others													
	Total	**23.9**	**23.7**	**24.6**	**29.2**	**819.7**	**520.0**	**449.5**	**27.0**	**28.0**	**42.6**	**73.1**	**87.2**	**672.8**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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	(24)	(48)	(72)	(98)	(123)	(150)	(176)	(203)	(231)	(274)	(347)	(434)	(545)
T	**Total Requirements**	**9,871**	**10,003**	**9,852**	**9,968**	**9,750**	**9,795**	**9,953**	**9,975**	**9,897**	**10,032**	**10,341**	**10,757**	**11,260**
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				4									
&	New Resources					794	1,288	1,711	1,711	1,711	1,711	1,711	1,711	2,272
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,966**	**11,742**	**11,966**	**12,374**	**12,135**	**12,139**	**12,022**	**11,984**	**11,846**	**12,386**
	Reserves	1,225	1,182	1,279	997	1,993	2,171	2,420	2,159	2,241	1,989	1,642	1,088	1,126
	Reserve Margin (RM) (%	12.4	11.8	13.0	10.0	20.4	22.2	24.3	21.6	22.6	19.8	15.9	10.1	10.0

Environmental Adder of $10 /Ton CO2
$ 1,000 /Ton NOx and $ 1,250 /Ton TSP
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	6.0	12.0	18.2	24.5	31.1	37.6	44.3	51.1	58.2	68.8	86.6	107.5	134.0
	OWC Geothermal													
O	OWC Cogen 1					148.9	200.1	200.1	200.1	200.1	200.1	200.1	200.1	200.1
W	OWC Cogen 2					437.3	874.6	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.0**	**12.0**	**18.2**	**24.5**	**617.3**	**1,112.4**	**1,537.8**	**1,544.6**	**1,551.6**	**1,562.3**	**1,580.0**	**1,601.0**	**1,627.4**
	DSM Programs	0.5	1.0	1.6	2.1	2.6	3.1	3.7	4.2	4.8	5.6	7.0	8.6	10.6
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**1.0**	**1.6**	**2.1**	**2.6**	**3.1**	**3.7**	**4.2**	**4.8**	**5.6**	**7.0**	**8.6**	**10.6**
	DSM Programs	8.6	17.0	26.0	35.6	45.0	54.9	64.8	74.9	85.4	101.6	130.7	166.3	212.7
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2					199.8	199.8	199.8	199.8	199.8	199.8	199.8	199.8	755.7
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**8.6**	**17.0**	**26.0**	**35.6**	**244.8**	**254.7**	**264.6**	**274.7**	**285.2**	**301.5**	**330.5**	**366.2**	**968.4**
	DSM Programs	2.7	5.4	8.1	10.8	13.7	16.6	19.6	22.6	25.7	30.3	38.0	47.0	58.4
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.7**	**5.4**	**8.1**	**10.8**	**13.7**	**16.6**	**19.6**	**22.6**	**25.7**	**30.3**	**38.0**	**47.0**	**58.4**
	DSM Programs	17.7	35.4	53.9	73.0	92.3	112.2	132.3	152.8	174.0	206.4	262.3	329.5	415.7
	Short Term Cap Purch													
T	Cogeneration					786.1	1,274.6	1,693.3	1,693.3	1,693.3	1,693.3	1,693.3	1,693.3	2,249.2
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**17.7**	**35.4**	**53.9**	**73.0**	**878.3**	**1,386.8**	**1,825.6**	**1,846.1**	**1,867.3**	**1,899.7**	**1,955.5**	**2,022.8**	**2,664.9**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	229.3	256.4	249.4	224.7	254.3	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	93.0	185.7	181.1	224.7	758.3	1,182.0	1,266.9	1,250.4	1,271.3	1,270.1	1,277.8	1,238.0	1,249.8
E	**DSM Programs**	(17.7)	(35.4)	(53.9)	(73.0)	(92.3)	(112.2)	(132.3)	(152.8)	(174.0)	(206.4)	(262.2)	(329.5)	(415.7)
M	**Total Requirements**	8,115.9	8,162.5	7,977.3	7,918.9	8,350.0	8,767.6	8,955.8	8,988.1	8,940.8	9,004.3	9,250.3	9,492.0	9,850.8
	Existing Generation	6,383.4	6,365.9	6,217.6	6,172.3	6,360.1	6,586.9	6,394.5	6,438.1	6,385.4	6,441.0	6,699.5	6,917.0	6,788.9
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	711.3	493.4	483.2	464.8	464.6	464.6	446.0	443.9	408.6
&	**Short Term Purchases**	863.2	826.6	794.7	782.9	492.4	412.8	384.9	391.9	397.5	405.3	411.4	437.8	404.2
R	**New Resources**					786.1	1,274.6	1,693.3	1,693.3	1,693.3	1,693.3	1,693.3	1,693.3	2,249.2
	Total Resources	8,115.9	8,162.5	7,977.2	7,918.9	8,349.9	8,767.6	8,955.8	8,988.1	8,940.7	9,004.2	9,250.3	9,492.0	9,850.8

Environmental Adder of $10 /Ton CO2
$ 1,000 /Ton NOx and $ 1,250 /Ton TSP

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	18	36	55	74	93	113	134	154	176	208	262	328	411
			After Conservation													
			System Load (MWa)	5,707	5,757	5,849	5,982	6,085	6,208	6,343	6,502	6,596	6,699	7,102	7,493	7,886
	0.64		Energy Sales (MWa)	5,156	5,252	5,349	5,456	5,566	5,680	5,794	5,901	5,971	6,023	6,332	6,659	7,041
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,014	8,219	8,776	9,568	10,099	10,439	10,576	10,726	10,887	11,064	11,766	12,456	14,421
			Net Conservation Assets ($M)	18	36	54	71	87	101	115	130	145	163	202	232	267
			Utility Cost													
46,732	3.14	Nominal	**Operating Revenues ($M)**	2,215	2,262	2,371	2,454	2,536	2,604	2,747	2,890	3,008	3,116	3,395	3,788	4,361
	0.14	Real		2,215	2,196	2,235	2,245	2,253	2,247	2,300	2,350	2,375	2,388	2,381	2,432	2,487
	2.48	Nominal	Cost in mills/kWh	49.0	49.2	50.6	51.3	52.0	52.4	54.1	55.9	57.5	59.1	61.2	65.0	70.7
	-0.50	Real		49.0	47.7	47.7	47.0	46.2	45.2	45.3	45.5	45.4	45.3	42.9	41.7	40.3
		Nominal	Average Customer Bill ($)	1,654	1,667	1,719	1,746	1,776	1,794	1,861	1,926	1,973	2,013	2,094	2,241	2,429
		Real		1,654	1,618	1,620	1,598	1,578	1,547	1,558	1,566	1,558	1,543	1,469	1,439	1,385
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.9	-3.7	-5.5	-8.0	-11.0	-14.9	-19.5	-25.5	-48.6	-85.1	-147.4
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.7	-2.5	-3.6	-5.1	-7.1	-9.7	-20.9	-41.5	-87.8
			Energy Svc Charge ($M)	1.8	3.6	5.6	7.7	9.9	12.2	14.6	17.3	18.7	20.5	25.0	29.3	33.9
46,186	3.042	Nominal	**Total Resource Cost ($M)**	2,217	2,265	2,376	2,460	2,545	2,614	2,758	2,902	3,020	3,127	3,399	3,776	4,307
	0.04	Real		2,217	2,199	2,240	2,251	2,261	2,255	2,309	2,360	2,384	2,397	2,384	2,424	2,456
	2.27	Nominal	Cost in mills/kWh	48.9	48.9	50.2	50.8	51.4	51.6	53.2	54.8	56.2	57.4	59.0	61.9	66.3
	-0.71	Real		48.9	47.5	47.4	46.5	45.7	44.5	44.6	44.6	44.4	44.0	41.4	39.8	37.8

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.73**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.73**

Environmental Adder of $10 /Ton CO2
$ 1,000 /Ton NOx and $ 1,250 /Ton TSP

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	49,306	49,977	50,726	51,683	52,841	53,955	55,137	56,534	57,340	58,238	61,760	65,166	68,591
	MWa	5,629	5,705	5,791	5,900	6,032	6,159	6,294	6,454	6,546	6,648	7,050	7,439	7,830
	Total Annual Emissions (1000 Tons)													
0.95%	CO2	48,815	49,223	48,713	49,109	48,864	49,244	48,462	49,319	49,353	50,840	53,769	57,874	58,426
0.50%	NOx	106.0	105.4	102.3	101.8	104.1	107.7	103.8	104.7	103.7	106.4	111.7	119.0	116.6
0.34%	TSP	10.0	9.9	9.6	9.6	9.7	9.9	9.7	9.7	9.7	9.9	10.3	10.8	10.6
	Annual System Emission Rates (Pounds/MWh)													
-0.79%	CO2	1,980	1,970	1,921	1,900	1,849	1,825	1,758	1,745	1,721	1,746	1,741	1,776	1,704
-1.23%	NOx	4.30	4.22	4.03	3.94	3.94	3.99	3.76	3.70	3.62	3.66	3.62	3.65	3.40
-1.39%	TSP	0.40	0.40	0.38	0.37	0.37	0.37	0.35	0.34	0.34	0.34	0.33	0.33	0.31
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.48	97.00	95.98	93.40	92.19	88.78	88.12	86.94	88.17	87.94	89.70	86.04
	NOx	100	98.11	93.79	91.59	91.59	92.84	87.54	86.13	84.08	85.01	84.10	84.95	79.06
	TSP	100	97.83	93.96	92.02	90.89	90.92	86.73	85.20	83.44	83.90	82.56	82.37	76.65

20 Year Emissions (1000 Tons)	Average	Total
CO2	52,636	1,052,717
NOx	110	2,195
TSP	10	203

Environmental Adder of $25 /Ton CO2
$ 2,500 /Ton NOx and $ 3,125 /Ton TSP
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch													
	DSM Programs	8.7	9.0	9.0	9.2	9.3	9.3	9.4	9.5	9.4	14.0	23.2	27.5	34.3
	OWC Geothermal													
O	OWC Cogen 1					150.4	51.7							
W	OWC Cogen 2					441.8	441.8	423.0						
C	OWC Combined Cycle					423.0	423.0					39.8		135.6
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**8.7**	**9.0**	**9.0**	**9.2**	**1,024.5**	**925.8**	**432.4**	**9.5**	**9.4**	**14.0**	**63.0**	**27.5**	**169.9**
	DSM Programs	0.9	1.0	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.5	2.4	2.9	3.5
I	Idaho Cogen 1					28.2								
D	Idaho Cogen 2					216.2								
A	Idaho Combined Cycle					69.3								
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.9**	**1.0**	**0.9**	**0.9**	**314.6**	**0.9**	**1.0**	**0.9**	**1.0**	**1.5**	**2.4**	**2.9**	**3.5**
	DSM Programs	13.5	13.2	14.1	14.8	14.6	15.3	15.2	15.5	16.1	24.9	42.8	51.6	66.4
	Utah Wind			31.6										
	Utah Geothermal				100.0	100.0	100.0							
U	Utah Solar													
T	Utah Cogen 1					14.1								
A	Utah Cogen 2					376.0	376.0	376.0	376.0	169.2				
H	Utah Combined Cycle					423.0								69.2
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**13.5**	**13.2**	**45.7**	**114.8**	**927.7**	**491.3**	**391.2**	**391.5**	**185.3**	**24.9**	**42.8**	**51.6**	**135.6**
	DSM Programs	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	5.2	8.4	9.6	11.9
W	Wyo Wind			31.6										
Y	Wyo Combined Cycle					423.0	121.6							
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**3.2**	**3.2**	**34.9**	**3.3**	**426.3**	**125.0**	**3.4**	**3.5**	**3.5**	**5.2**	**8.4**	**9.6**	**11.9**
T	DSM Programs	26.3	26.4	27.3	28.2	28.1	28.9	29.0	29.4	30.0	45.6	76.8	91.6	116.1
O	Short Term Cap Purch													
T	Cogeneration					1,226.7	869.5	799.0	376.0	169.2				
A	Combined Cycle CT					1,338.3	544.6					39.8		204.8
L	All Others			63.2	100.0	100.0	100.0							
	Total	**26.3**	**26.4**	**90.5**	**128.2**	**2,693.1**	**1,543.0**	**828.0**	**405.4**	**199.2**	**45.6**	**116.6**	**91.6**	**320.9**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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	(26)	(53)	(80)	(108)	(136)	(165)	(194)	(224)	(254)	(299)	(376)	(468)	(584)
T	**Total Requirements**	**9,869**	**9,998**	**9,844**	**9,958**	**9,737**	**9,780**	**9,935**	**9,954**	**9,874**	**10,007**	**10,312**	**10,723**	**11,221**
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													
&	New Resources			63	163	2,828	4,342	5,141	5,517	5,686	5,686	5,726	5,726	5,931
R	**Total Resources**	**11,096**	**11,185**	**11,194**	**11,125**	**13,776**	**15,020**	**15,804**	**15,941**	**16,114**	**15,997**	**15,999**	**15,861**	**16,045**
	Reserves	1,227	1,187	1,350	1,167	4,040	5,241	5,869	5,986	6,240	5,990	5,687	5,137	4,823
	Reserve Margin (RM) (%	12.4	11.9	13.7	11.7	41.5	53.6	59.1	60.1	63.2	59.9	55.2	47.9	43.0

Environmental Adder of $25 /Ton CO2
$ 2,500 /Ton NOx and $ 3,125 /Ton TSP
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	6.8	13.8	20.9	28.1	35.5	42.9	50.3	57.9	65.4	76.6	95.2	117.2	144.9
	OWC Geothermal													
O	OWC Cogen 1					148.9	200.1	200.1	200.1	200.1	200.1	200.1	200.1	200.1
W	OWC Cogen 2					437.3	874.6	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3
C	OWC Combined Cycle					418.7	837.4	829.6	793.3	758.4	777.4	851.4	869.1	1,011.1
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**13.8**	**20.9**	**28.1**	**1,040.4**	**1,955.0**	**2,373.4**	**2,344.6**	**2,317.3**	**2,347.4**	**2,440.0**	**2,479.8**	**2,649.4**
	DSM Programs	0.6	1.3	1.9	2.5	3.1	3.8	4.4	5.1	5.7	6.7	8.4	10.3	12.8
I	Idaho Cogen 1					27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
D	Idaho Cogen 2					214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0
A	Idaho Combined Cycle					68.6	68.6	68.6	67.6	64.9	62.7	68.6	68.6	68.6
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**1.3**	**1.9**	**2.5**	**313.6**	**314.2**	**314.9**	**314.5**	**312.5**	**311.3**	**318.9**	**320.8**	**323.3**
	DSM Programs	9.6	19.0	29.0	39.7	50.1	61.1	72.1	83.4	95.1	113.1	144.2	182.1	230.9
	Utah Wind			35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3
	Utah Geothermal				94.8	189.6	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4
U	Utah Solar													
T	Utah Cogen 1					14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
A	Utah Cogen 2					372.2	744.4	1,116.5	1,488.7	1,656.2	1,656.2	1,656.2	1,656.2	1,656.2
H	Utah Combined Cycle					418.7	418.7	418.7	412.0	411.8	410.0	416.4	418.7	487.2
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**9.6**	**19.0**	**64.4**	**169.8**	**1,079.9**	**1,557.9**	**1,941.1**	**2,317.8**	**2,496.8**	**2,513.0**	**2,550.5**	**2,590.7**	**2,708.0**
	DSM Programs	2.7	5.4	8.1	10.8	13.7	16.6	19.6	22.6	25.7	30.3	38.0	47.1	58.5
W	Wyo Wind			35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3
Y	Wyo Combined Cycle					418.7	539.1	539.1	538.9	534.9	534.4	539.1	539.1	539.1
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.7**	**5.4**	**43.4**	**46.1**	**467.7**	**591.0**	**594.0**	**596.8**	**595.9**	**600.1**	**612.4**	**621.5**	**632.9**
	DSM Programs	19.7	39.4	59.9	81.1	102.3	124.3	146.5	168.9	191.9	226.7	285.8	356.7	447.0
	Short Term Cap Purch													
T	Cogeneration					1,214.3	2,075.0	2,865.9	3,238.1	3,405.6	3,405.6	3,405.6	3,405.6	3,405.6
O	Combined Cycle CT					1,324.7	1,863.8	1,856.0	1,811.8	1,770.0	1,784.4	1,875.4	1,895.4	2,105.9
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**19.7**	**39.4**	**59.9**	**81.1**	**2,641.3**	**4,063.1**	**4,868.3**	**5,218.7**	**5,367.4**	**5,416.7**	**5,566.8**	**5,657.6**	**5,958.5**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	224.6	225.7	213.5	199.8	224.0	257.7	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**						415.0	777.4	842.8	969.6	885.4	855.8	698.1	629.1
E	**DSM Programs**	(19.7)	(39.4)	(59.9)	(81.1)	(102.3)	(124.3)	(146.5)	(168.9)	(191.9)	(226.7)	(285.8)	(356.7)	(447.0)
M	**Total Requirements**	8,016.2	7,942.0	7,754.3	7,661.2	7,551.3	7,987.7	8,452.2	8,564.4	8,621.2	8,599.2	8,804.7	8,924.9	9,198.8
	Existing Generation	6,136.6	5,961.8	5,708.4	5,521.7	3,030.9	2,470.5	2,291.0	2,127.7	2,066.9	2,022.3	2,167.9	2,188.6	2,268.1
L	**Long Term Purchases**	979.6	1,080.2	1,075.3	1,074.0	821.1	586.0	505.5	465.9	465.9	465.9	447.1	466.4	439.4
&	**Short Term Purchases**	900.0	900.0	900.0	900.0	900.0	637.4	578.7	565.8	557.9	565.9	553.6	613.9	624.6
R	**New Resources**			70.7	165.5	2,799.3	4,293.9	5,077.0	5,404.9	5,530.6	5,545.1	5,636.1	5,656.1	5,866.6
	Total Resources	8,016.2	7,942.0	7,754.3	7,661.2	7,551.3	7,987.7	8,452.2	8,564.4	8,621.2	8,599.1	8,804.7	8,925.0	9,198.8

Environmental Adder of $25 /Ton CO2
$ 2,500 /Ton NOx and $ 3,125 /Ton TSP

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	20	39	60	81	102	124	146	169	192	227	286	357	447
			After Conservation													
			System Load (MWa)	5,706	5,753	5,844	5,975	6,076	6,197	6,330	6,488	6,580	6,680	7,079	7,464	7,851
	0.63		Energy Sales (MWa)	5,155	5,249	5,344	5,450	5,558	5,669	5,782	5,887	5,956	6,005	6,310	6,632	7,008
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,148	8,695	10,219	12,427	13,625	14,221	14,515	14,621	14,635	14,666	14,955	15,196	15,975
			Net Conservation Assets ($M)	19	38	57	75	92	108	123	140	156	177	220	254	291
			Utility Cost													
57,075	3.39	Nominal	**Operating Revenues ($M)**	2,296	2,370	2,512	2,656	3,046	3,437	3,698	3,898	4,062	4,203	4,461	4,880	5,448
	0.38	Real		2,296	2,301	2,367	2,430	2,706	2,965	3,097	3,169	3,206	3,221	3,129	3,132	3,107
	2.74	Nominal	Cost in mills/kWh	50.9	51.6	53.7	55.6	62.6	69.2	73.0	75.6	77.8	79.9	80.7	84.0	88.8
	-0.26	Real		50.9	50.1	50.6	50.9	55.6	59.7	61.1	61.5	61.5	61.2	56.6	53.9	50.6
		Nominal	Average Customer Bill ($)	1,714	1,746	1,820	1,890	2,133	2,368	2,505	2,597	2,664	2,715	2,751	2,887	3,035
		Real		1,714	1,695	1,716	1,730	1,895	2,042	2,098	2,112	2,103	2,081	1,929	1,853	1,731
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.8	-3.6	-5.4	-7.8	-10.8	-14.7	-19.2	-25.1	-48.0	-84.2	-146.2
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-5.0	-6.9	-9.5	-20.6	-40.9	-86.8
			Energy Svc Charge ($M)	1.9	3.9	6.0	8.2	10.5	13.0	15.5	18.5	20.1	22.2	27.4	32.4	37.7
56,557	3.303	Nominal	**Total Resource Cost ($M)**	2,298	2,374	2,517	2,663	3,055	3,448	3,710	3,911	4,075	4,216	4,467	4,871	5,399
	0.29	Real		2,298	2,304	2,372	2,437	2,714	2,974	3,107	3,180	3,217	3,231	3,133	3,127	3,079
	2.53	Nominal	Cost in mills/kWh	50.7	51.3	53.2	55.0	61.7	68.1	71.6	73.9	75.9	77.5	77.6	79.9	83.1
	-0.45	Real		50.7	49.8	50.2	50.4	54.8	58.7	59.9	60.1	59.9	59.4	54.4	51.3	47.4

Notes:

1) **$M = millions of dollars** 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **52.36**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **49.87**

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Environmental Adder of $25 /Ton CO2
$ 2,500 /Ton NOx and $ 3,125 /Ton TSP

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	49,248	49,672	50,360	51,393	52,487	53,842	55,013	56,393	57,184	58,060	61,554	64,929	68,316
	MWa	5,622	5,670	5,749	5,867	5,992	6,146	6,280	6,438	6,528	6,628	7,027	7,412	7,799
	Total Annual Emissions (1000 Tons)													
-2.46%	CO2	46,792	46,363	44,913	44,096	27,029	22,514	21,820	21,444	21,401	22,272	24,384	27,243	29,177
-7.51%	NOx	99.7	96.4	90.9	87.3	33.8	21.7	18.4	15.5	14.3	15.1	17.7	20.9	22.6
-8.03%	TSP	9.2	9.0	8.5	8.2	2.7	1.7	1.5	1.3	1.2	1.3	1.5	1.8	1.9
	Annual System Emission Rates (Pounds/MWh)													
-4.12%	CO2	1,900	1,867	1,784	1,716	1,030	836	793	761	749	767	792	839	854
-9.09%	NOx	4.05	3.88	3.61	3.40	1.29	0.81	0.67	0.55	0.50	0.52	0.57	0.65	0.66
-9.60%	TSP	0.38	0.36	0.34	0.32	0.10	0.06	0.05	0.05	0.04	0.04	0.05	0.05	0.06
	Emission Rates as Percent of 1997 Base													
	CO2	100	98.24	93.87	90.31	54.20	44.01	41.74	40.02	39.39	40.37	41.69	44.16	44.95
	NOx	100	95.90	89.18	83.94	31.83	19.94	16.56	13.54	12.38	12.81	14.19	15.94	16.36
	TSP	100	96.26	89.54	85.44	26.91	16.90	14.28	12.16	11.31	11.70	12.72	14.36	14.71

20 Year Emissions (1000 Tons)	Average	Total
CO2	29,118	582,358
NOx	35	691
TSP	3	61

Environmental Adder of $40 /Ton CO2
$ 4,000 /Ton NOx and $ 5,000 /Ton TSP
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch													
	DSM Programs	8.7	9.0	9.0	9.2	9.3	9.3	9.4	9.5	9.4	14.0	23.2	27.5	34.3
	OWC Geothermal				100.0	100.0	100.0							
O	OWC Cogen 1					150.4	51.7							
W	OWC Cogen 2					441.8	441.8	423.0						
C	OWC Combined Cycle					423.0								
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**8.7**	**9.0**	**9.0**	**109.2**	**1,124.5**	**602.8**	**432.4**	**9.5**	**9.4**	**14.0**	**23.2**	**27.5**	**34.3**
	DSM Programs	0.9	1.0	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.5	2.4	2.9	3.5
I	Idaho Cogen 1					28.2								
D	Idaho Cogen 2					216.2								
A	Idaho Combined Cycle					213.2								
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.9**	**1.0**	**0.9**	**0.9**	**458.5**	**0.9**	**1.0**	**0.9**	**1.0**	**1.5**	**2.4**	**2.9**	**3.5**
	DSM Programs	13.5	13.2	14.1	14.8	14.6	15.3	15.2	15.5	16.1	24.9	42.8	51.6	66.4
	Utah Wind			31.6										
	Utah Geothermal				100.0	100.0	100.0							
U	Utah Solar													
T	Utah Cogen 1					14.1								
A	Utah Cogen 2					376.0	376.0	376.0	376.0	169.2				
H	Utah Combined Cycle					423.0	147.8						89.0	280.4
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**13.5**	**13.2**	**45.7**	**114.8**	**927.7**	**639.1**	**391.2**	**391.5**	**185.3**	**24.9**	**42.8**	**140.6**	**346.8**
	DSM Programs	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	5.2	8.4	9.6	11.9
W	Wyo Wind			31.6										
Y	Wyo Combined Cycle					423.0	254.0							
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**3.2**	**3.2**	**34.9**	**3.3**	**426.3**	**257.4**	**3.4**	**3.5**	**3.5**	**5.2**	**8.4**	**9.6**	**11.9**
T	DSM Programs	26.3	26.4	27.3	28.2	28.1	28.9	29.0	29.4	30.0	45.6	76.8	91.6	116.1
O	Short Term Cap Purch													
T	Cogeneration					1,226.7	869.5	799.0	376.0	169.2				
A	Combined Cycle CT					1,482.2	401.8						89.0	280.4
L	All Others			63.2	200.0	200.0	200.0							
	Total	**26.3**	**26.4**	**90.5**	**228.2**	**2,937.0**	**1,500.2**	**828.0**	**405.4**	**199.2**	**45.6**	**76.8**	**180.6**	**396.5**
	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	(26)	(53)	(80)	(108)	(136)	(165)	(194)	(224)	(254)	(299)	(376)	(468)	(584)
T	**Total Requirements**	**9,869**	**9,998**	**9,844**	**9,958**	**9,737**	**9,780**	**9,935**	**9,954**	**9,874**	**10,007**	**10,312**	**10,723**	**11,221**
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													
&	New Resources			63	263	3,172	4,643	5,442	5,818	5,988	5,988	5,988	6,077	6,357
R	**Total Resources**	**11,096**	**11,185**	**11,194**	**11,225**	**14,120**	**15,321**	**16,105**	**16,242**	**16,416**	**16,299**	**16,261**	**16,212**	**16,471**
	Reserves	1,227	1,187	1,350	1,267	4,384	5,542	6,170	6,288	6,541	6,291	5,948	5,487	5,249
	Reserve Margin (RM) (%	12.4	11.9	13.7	12.7	45.0	56.7	62.1	63.2	66.2	62.9	57.7	51.2	46.8

Environmental Adder of $40 /Ton CO2
$ 4,000 /Ton NOx and $ 5,000 /Ton TSP
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	6.8	13.8	20.9	28.1	35.5	42.9	50.3	57.9	65.4	76.6	95.2	117.2	144.9
	OWC Geothermal				94.8	189.6	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4
O	OWC Cogen 1					148.9	200.1	200.1	200.1	200.1	200.1	200.1	200.1	200.1
W	OWC Cogen 2					437.3	874.6	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3	1,293.3
C	OWC Combined Cycle					418.7	418.7	401.0	359.1	322.8	334.4	383.6	406.7	413.5
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**13.8**	**20.9**	**123.0**	**1,230.0**	**1,820.7**	**2,229.2**	**2,194.9**	**2,166.1**	**2,188.9**	**2,256.7**	**2,301.8**	**2,336.2**
	DSM Programs	0.6	1.3	1.9	2.5	3.1	3.8	4.4	5.1	5.7	6.7	8.4	10.3	12.8
I	Idaho Cogen 1					27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
D	Idaho Cogen 2					214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0
A	Idaho Combined Cycle					211.0	211.0	211.0	199.7	190.3	199.0	209.4	211.0	211.0
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**1.3**	**1.9**	**2.5**	**456.1**	**456.7**	**457.3**	**446.7**	**437.9**	**447.6**	**459.7**	**463.3**	**465.7**
	DSM Programs	9.6	19.0	29.0	39.7	50.1	61.1	72.1	83.4	95.1	113.1	144.2	182.1	230.9
	Utah Wind			35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3
	Utah Geothermal				94.8	189.6	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4
U	Utah Solar													
T	Utah Cogen 1					14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
A	Utah Cogen 2					372.2	744.4	1,116.5	1,488.7	1,656.2	1,656.2	1,656.2	1,656.2	1,656.2
H	Utah Combined Cycle					418.7	565.0	565.0	547.3	527.6	531.6	553.0	645.8	930.6
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**9.6**	**19.0**	**64.4**	**169.8**	**1,079.9**	**1,704.2**	**2,087.4**	**2,453.1**	**2,612.5**	**2,634.6**	**2,687.1**	**2,817.8**	**3,151.4**
	DSM Programs	2.7	5.4	8.1	10.8	13.7	16.6	19.6	22.6	25.7	30.3	38.0	47.1	58.5
W	Wyo Wind			35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3
Y	Wyo Combined Cycle					418.7	670.1	669.9	662.8	657.3	662.5	669.1	670.1	670.1
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.7**	**5.4**	**43.4**	**46.1**	**467.7**	**722.0**	**724.8**	**720.8**	**718.3**	**728.2**	**742.5**	**752.5**	**763.9**
	DSM Programs	19.7	39.4	59.9	81.1	102.3	124.3	146.5	168.9	191.9	226.7	285.8	356.7	447.0
	Short Term Cap Purch													
T	Cogeneration					1,214.3	2,075.0	2,865.9	3,238.1	3,405.6	3,405.6	3,405.6	3,405.6	3,405.6
O	Combined Cycle CT					1,467.1	1,864.9	1,846.9	1,769.0	1,697.9	1,727.5	1,815.1	1,933.6	2,225.2
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**19.7**	**39.4**	**59.9**	**81.1**	**2,783.8**	**4,064.2**	**4,859.3**	**5,176.0**	**5,295.4**	**5,359.7**	**5,506.5**	**5,695.8**	**6,077.7**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	244.5	236.5	257.8	233.5	211.4	251.7	258.3	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**						225.0	638.1	780.7	937.9	835.9	732.8	507.4	464.3
E	**DSM Programs**	(19.7)	(39.4)	(59.9)	(81.1)	(102.3)	(124.3)	(146.5)	(168.9)	(191.9)	(226.7)	(285.8)	(356.7)	(447.0)
M	**Total Requirements**	8,036.1	7,952.9	7,798.6	7,694.9	7,538.6	7,791.7	8,312.7	8,502.3	8,589.6	8,549.7	8,681.7	8,734.2	9,034.0
	Existing Generation	6,156.5	5,972.6	5,752.7	5,460.7	2,686.1	1,913.3	1,876.6	1,859.9	1,855.2	1,780.4	1,795.5	1,678.1	1,678.0
L	**Long Term Purchases**	979.6	1,080.2	1,075.3	1,074.0	821.1	583.2	494.5	465.9	465.9	465.9	447.1	457.4	418.6
&	**Short Term Purchases**	900.0	900.0	900.0	900.0	900.0	715.8	589.2	529.9	525.4	530.8	578.9	620.1	667.2
R	**New Resources**			70.7	260.3	3,131.4	4,579.4	5,352.4	5,646.6	5,743.0	5,772.5	5,860.2	5,978.7	6,270.3
	Total Resources	8,036.1	7,952.9	7,798.6	7,694.9	7,538.6	7,791.8	8,312.7	8,502.3	8,589.5	8,549.6	8,681.7	8,734.2	9,034.0

Environmental Adder of $40 /Ton CO2
$ 4,000 /Ton NOx and $ 5,000 /Ton TSP

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	20	39	60	81	102	124	146	169	192	227	286	357	447
			After Conservation													
			System Load (MWa)	5,706	5,753	5,844	5,975	6,076	6,197	6,330	6,488	6,580	6,680	7,079	7,464	7,851
	0.63		Energy Sales (MWa)	5,155	5,249	5,344	5,450	5,558	5,669	5,782	5,887	5,956	6,005	6,310	6,632	7,008
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,161	8,842	10,708	13,234	14,533	15,084	15,333	15,393	15,361	15,345	15,471	15,674	16,392
			Net Conservation Assets ($M)	19	38	57	75	92	108	123	140	156	177	220	254	291
			Utility Cost													
59,157	3.39	Nominal	**Operating Revenues ($M)**	2,347	2,432	2,590	2,756	3,163	3,649	3,914	4,082	4,228	4,365	4,633	5,070	5,664
	0.38	Real		2,347	2,361	2,442	2,523	2,811	3,148	3,278	3,319	3,337	3,346	3,250	3,254	3,230
	2.74	Nominal	Cost in mills/kWh	52.0	52.9	55.3	57.7	65.0	73.5	77.3	79.2	81.0	83.0	83.8	87.3	92.3
	-0.25	Real		52.0	51.4	52.2	52.8	57.7	63.4	64.7	64.4	64.0	63.6	58.8	56.0	52.6
		Nominal	Average Customer Bill ($)	1,752	1,792	1,878	1,962	2,215	2,514	2,651	2,720	2,773	2,820	2,857	3,000	3,155
		Real		1,752	1,740	1,770	1,795	1,968	2,168	2,221	2,212	2,189	2,161	2,004	1,926	1,799
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.8	-3.6	-5.4	-7.8	-10.8	-14.7	-19.2	-25.1	-48.0	-84.2	-146.2
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-5.0	-6.9	-9.5	-20.6	-40.9	-86.8
			Energy Svc Charge ($M)	1.9	3.9	6.0	8.2	10.5	13.0	15.5	18.5	20.1	22.2	27.4	32.4	37.7
58,640	3.309	Nominal	**Total Resource Cost ($M)**	2,349	2,436	2,596	2,764	3,172	3,660	3,926	4,095	4,241	4,378	4,640	5,062	5,615
	0.30	Real		2,349	2,365	2,447	2,529	2,818	3,157	3,288	3,330	3,348	3,355	3,255	3,249	3,202
	2.54	Nominal	Cost in mills/kWh	51.8	52.6	54.9	57.1	64.1	72.2	75.8	77.4	78.9	80.4	80.6	83.0	86.4
	-0.45	Real		51.8	51.1	51.7	52.3	56.9	62.3	63.4	62.9	62.3	61.6	56.5	53.3	49.3

Notes:

1) $M = millions of dollars 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **54.27**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **51.71**

Environmental Adder of $40 /Ton CO2
$ 4,000 /Ton NOx and $ 5,000 /Ton TSP

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	49,422	49,767	50,748	51,689	52,376	53,789	55,012	56,393	57,184	58,060	61,554	64,928	68,317
	MWa	5,642	5,681	5,793	5,901	5,979	6,140	6,280	6,438	6,528	6,628	7,027	7,412	7,799
	Total Annual Emissions (1000 Tons)													
-3.26%	CO2	46,702	46,242	44,534	42,752	24,414	18,502	18,516	18,881	19,134	19,845	21,300	23,399	24,900
-10.84%	NOx	99.2	95.9	89.5	83.6	27.1	11.2	10.5	10.1	10.1	10.2	10.5	11.1	11.2
-10.73%	TSP	9.2	9.0	8.5	8.0	2.1	1.0	0.9	0.9	0.9	0.9	1.0	1.0	1.1
	Annual System Emission Rates (Pounds/MWh)													
-4.89%	CO2	1,890	1,858	1,755	1,654	932	688	673	670	669	684	692	721	729
-12.35%	NOx	4.01	3.85	3.53	3.23	1.03	0.42	0.38	0.36	0.35	0.35	0.34	0.34	0.33
-12.23%	TSP	0.37	0.36	0.33	0.31	0.08	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	Emission Rates as Percent of 1997 Base													
	CO2	100	98.33	92.87	87.53	49.33	36.40	35.62	35.43	35.41	36.17	36.62	38.14	38.57
	NOx	100	96.00	87.84	80.57	25.78	10.41	9.47	8.95	8.77	8.77	8.48	8.49	8.18
	TSP	100	96.44	89.62	82.55	21.20	9.62	9.01	8.67	8.55	8.61	8.43	8.56	8.38

20 Year Emissions (1000 Tons)	Average	Total
CO2	26,371	527,412
NOx	28	556
TSP	3	52

Solar Technological Price Curve
Necessary to Bring in Solar
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.1				65.5		122.7	229.9	480.6	500.0
	DSM Programs	6.9	7.1	7.2	7.2	7.7	7.7	7.9	7.8	7.8	12.5	20.6	24.3	30.6
	OWC Geothermal													
O	OWC Cogen 1													63.7
W	OWC Cogen 2						187.9	196.6	117.4		123.8	274.4	350.0	56.5
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.9**	**7.1**	**7.2**	**7.2**	**7.7**	**195.6**	**204.5**	**125.2**	**7.8**	**136.3**	**295.0**	**374.3**	**150.8**
	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.9	1.6	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.9**	**1.6**	**1.9**	**2.4**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	12.9	13.6	14.4	22.2	39.1	47.2	61.3
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													324.0
T	Utah Cogen 1													
A	Utah Cogen 2													116.0
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**12.9**	**13.6**	**14.4**	**22.2**	**39.1**	**47.2**	**501.3**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	2.9	3.0	3.0	3.1	4.6	8.1	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**2.9**	**3.0**	**3.0**	**3.1**	**4.6**	**8.1**	**9.5**	**11.9**
T	DSM Programs	21.8	21.6	22.5	23.1	23.6	24.2	24.4	25.0	25.9	40.2	69.4	82.9	106.2
O	Short Term Cap Purch				13.1				65.5		122.7	229.9	480.6	500.0
T	Cogeneration						187.9	196.6	117.4		123.8	274.4	350.0	236.2
A	Combined Cycle CT													
L	All Others													324.0
	Total	**21.8**	**21.6**	**22.5**	**36.2**	**23.6**	**212.1**	**221.0**	**207.9**	**25.9**	**286.7**	**573.7**	**913.5**	**1,166.4**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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)	(113)	(137)	(161)	(186)	(212)	(252)	(322)	(405)	(511)
T	**Total Requirements**	**9,873**	**10,008**	**9,858**	**9,977**	**9,760**	**9,808**	**9,968**	**9,992**	**9,916**	**10,054**	**10,366**	**10,786**	**11,294**
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				66		123	230	481	500
&	New Resources						188	384	502	502	625	900	1,250	1,810
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**10,866**	**11,047**	**10,992**	**10,930**	**11,059**	**11,403**	**11,866**	**12,424**
	Reserves	1,223	1,178	1,273	998	1,188	1,058	1,079	999	1,014	1,005	1,036	1,079	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

Solar Technological Price Curve
Necessary to Bring in Solar
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.4	10.8	16.4	22.1	28.2	34.4	40.6	46.9	53.2	63.0	79.3	98.6	122.8
	OWC Geothermal													
O	OWC Cogen 1													63.1
W	OWC Cogen 2						182.9	344.3	449.4	449.4	532.5	766.1	1,063.9	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.4**	**10.8**	**16.4**	**22.1**	**28.2**	**217.2**	**384.9**	**496.3**	**502.6**	**595.5**	**845.3**	**1,162.5**	**1,297.9**
	DSM Programs	0.5	0.9	1.3	1.8	2.2	2.7	3.1	3.6	4.1	4.8	6.1	7.7	9.7
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.2**	**2.7**	**3.1**	**3.6**	**4.1**	**4.8**	**6.1**	**7.7**	**9.7**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	68.0	78.0	93.7	121.2	154.8	198.6
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													112.7
T	Utah Cogen 1													
A	Utah Cogen 2													98.8
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.0**	**78.0**	**93.7**	**121.2**	**154.8**	**410.1**
	DSM Programs	2.2	4.5	6.8	9.1	11.4	13.8	16.2	18.6	21.1	24.7	31.5	39.9	51.1
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.4**	**13.8**	**16.2**	**18.6**	**21.1**	**24.7**	**31.5**	**39.9**	**51.1**
	DSM Programs	15.9	31.6	48.0	65.1	82.4	100.3	118.3	137.1	156.3	186.1	238.0	300.9	382.2
	Short Term Cap Purch				0.0				0.1		0.1	0.2	0.5	0.5
T	Cogeneration						182.9	344.3	449.4	449.4	532.5	766.1	1,063.9	1,273.8
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.9**	**31.6**	**48.0**	**65.1**	**82.4**	**283.2**	**462.6**	**586.5**	**605.7**	**718.7**	**1,004.3**	**1,365.3**	**1,656.6**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.4	984.2	1,103.2	1,156.0	1,198.0	1,247.2	1,297.7	1,276.4	1,344.0	1,291.2	1,298.5	1,211.9	1,177.0
E	**DSM Programs**	(15.9)	(31.6)	(48.0)	(65.1)	(82.4)	(100.3)	(118.3)	(137.1)	(156.3)	(186.1)	(238.0)	(300.9)	(382.2)
M	**Total Requirements**	8,986.7	9,017.6	8,962.9	8,891.8	8,803.7	8,844.7	9,000.6	9,029.9	9,031.2	9,045.6	9,295.2	9,494.5	9,811.5
	Existing Generation	7,773.9	7,713.8	7,661.5	7,604.7	7,741.9	7,808.1	7,821.6	7,762.4	7,761.6	7,689.3	7,705.0	7,601.7	7,628.5
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.4	333.9	336.4	323.4	349.1	357.7	349.2	352.2	354.3	357.8	376.8	384.5	387.3
R	**New Resources**						182.8	344.3	449.5	449.4	532.6	766.3	1,064.4	1,387.1
	Total Resources	8,986.7	9,017.7	8,962.9	8,891.8	8,803.7	8,844.7	9,000.7	9,029.9	9,031.2	9,045.6	9,295.2	9,494.5	9,811.5

Solar Technological Price Curve
Necessary to Bring in Solar

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	32	48	65	82	100	118	137	156	186	238	301	382
			After Conservation													
			System Load (MWa)	5,710	5,761	5,856	5,991	6,096	6,221	6,358	6,519	6,615	6,720	7,126	7,520	7,915
	0.65		Energy Sales (MWa)	5,158	5,256	5,355	5,464	5,576	5,692	5,808	5,917	5,989	6,043	6,355	6,683	7,068
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,179	8,404	8,645	8,962	9,266	9,506	9,730	9,997	10,206	11,277	12,399	17,344
			Net Conservation Assets ($M)	16	33	49	64	78	92	104	117	130	146	181	210	243
			Utility Cost													
46,665	3.23	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,283	2,358	2,450	2,452	2,549	2,682	2,798	2,941	3,278	3,794	4,561
	0.22	Real		2,146	2,127	2,151	2,158	2,177	2,115	2,135	2,180	2,209	2,254	2,299	2,435	2,601
	2.57	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.3	50.2	49.2	50.1	51.7	53.3	55.6	58.9	64.8	73.7
	-0.42	Real		47.5	46.2	45.9	45.1	44.6	42.4	42.0	42.1	42.1	42.6	41.3	41.6	42.0
		Nominal	Average Customer Bill ($)	1,602	1,614	1,654	1,678	1,716	1,689	1,727	1,787	1,835	1,900	2,022	2,245	2,541
		Real		1,602	1,567	1,559	1,536	1,524	1,457	1,446	1,453	1,449	1,456	1,418	1,441	1,449
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.9	-3.7	-5.4	-7.8	-10.7	-14.3	-18.6	-24.1	-45.3	-79.1	-138.3
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-5.0	-6.8	-9.3	-19.8	-39.0	-82.2
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.2	26.1	30.6
46,118	3.128	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,287	2,364	2,458	2,460	2,559	2,692	2,808	2,950	3,281	3,781	4,510
	0.12	Real		2,147	2,129	2,156	2,164	2,184	2,122	2,143	2,189	2,217	2,261	2,301	2,427	2,572
	2.36	Nominal	Cost in mills/kWh	47.4	47.4	48.4	48.9	49.6	48.6	49.4	50.9	52.3	54.2	57.0	62.0	69.4
	-0.62	Real		47.4	46.0	45.6	44.7	44.1	41.9	41.3	41.4	41.3	41.5	40.0	39.8	39.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.56**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.67**

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Solar Technological Price Curve Necessary to Bring in Solar

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,020	50,473	51,283	52,047	52,964	54,059	55,261	56,673	57,495	58,416	61,973	65,417	68,884
	MWa	5,710	5,762	5,854	5,941	6,046	6,171	6,308	6,469	6,563	6,669	7,075	7,468	7,863
	Total Annual Emissions (1000 Tons)													
0.61%	CO2	56,583	56,896	56,926	57,405	57,466	57,084	57,605	57,837	58,176	58,888	60,288	62,343	63,464
0.03%	NOx	132.6	131.7	130.4	130.2	132.2	132.6	132.8	131.6	131.6	131.8	132.1	132.8	133.3
0.12%	TSP	11.8	11.7	11.7	11.7	11.8	11.8	11.8	11.8	11.8	11.9	11.9	12.0	12.1
	Annual System Emission Rates (Pounds/MWh)													
-1.07%	CO2	2,262	2,255	2,220	2,206	2,170	2,112	2,085	2,041	2,024	2,016	1,946	1,906	1,843
-1.64%	NOx	5.30	5.22	5.09	5.00	4.99	4.90	4.80	4.64	4.58	4.51	4.26	4.06	3.87
-1.55%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.41	0.38	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.13	97.50	95.91	93.35	92.15	90.22	89.45	89.11	86.00	84.25	81.45
	NOx	100	98.43	95.95	94.39	94.15	92.52	90.64	87.62	86.36	85.12	80.40	76.57	73.04
	TSP	100	98.60	96.58	95.40	94.39	92.53	90.66	88.23	87.15	86.10	81.49	77.70	74.33

20 Year Emissions (1000 Tons)	Average	Total
CO2	59,574	1,191,480
NOx	132	2,643
TSP	12	238

Low Natural Gas Price Escalation
(0.3% till 2006, -0.3% thereafter)
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				19.3							78.1	381.1	500.0
	DSM Programs	6.2	6.4	6.4	7.1	7.2	7.2	7.4	7.3	7.3	10.8	18.7	22.2	27.9
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2						266.6	168.8	141.3		185.7	309.4	234.8	
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT												70.7	
	OWC Pump Storage													
	Total	**6.2**	**6.4**	**6.4**	**7.1**	**7.2**	**273.8**	**176.2**	**148.6**	**7.3**	**196.5**	**328.1**	**327.7**	**27.9**
	DSM Programs	0.5	0.5	0.6	0.5	0.5	0.6	0.6	0.6	0.6	0.9	1.5	1.7	2.1
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.5**	**0.6**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.9**	**1.5**	**1.7**	**2.1**
	DSM Programs	9.9	10.7	11.8	12.5	12.4	12.9	12.9	13.0	13.6	21.0	36.4	43.8	56.8
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													470.7
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**9.9**	**10.7**	**11.8**	**12.5**	**12.4**	**12.9**	**12.9**	**13.0**	**13.6**	**21.0**	**36.4**	**43.8**	**527.5**
	DSM Programs	2.5	2.5	2.5	2.8	2.9	3.0	3.0	3.0	3.0	4.5	7.4	8.2	10.3
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.5**	**2.5**	**2.5**	**2.8**	**2.9**	**3.0**	**3.0**	**3.0**	**3.0**	**4.5**	**7.4**	**8.2**	**10.3**
T	DSM Programs	19.1	20.1	21.3	22.9	23.0	23.7	23.9	23.9	24.5	37.2	64.0	75.9	97.1
O	Short Term Cap Purch				19.3							78.1	381.1	500.0
T	Cogeneration						266.6	168.8	141.3		185.7	309.4	234.8	470.7
A	Combined Cycle CT													
L	All Others												70.7	
	Total	**19.1**	**20.1**	**21.3**	**42.2**	**23.0**	**290.3**	**192.7**	**165.2**	**24.5**	**222.9**	**451.5**	**762.5**	**1,067.8**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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	(19)	(39)	(60)	(83)	(107)	(130)	(154)	(178)	(202)	(240)	(304)	(380)	(477)
T	**Total Requirements**	**9,876**	**10,012**	**9,864**	**9,983**	**9,766**	**9,815**	**9,975**	**10,000**	**9,926**	**10,066**	**10,384**	**10,811**	**11,328**
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				19							78	381	500
&	New Resources						267	435	577	577	762	1,072	1,377	1,848
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,981**	**10,948**	**10,945**	**11,098**	**11,001**	**11,005**	**11,073**	**11,423**	**11,893**	**12,462**
	Reserves	1,220	1,174	1,268	998	1,182	1,130	1,123	1,000	1,079	1,007	1,038	1,081	1,133
	Reserve Margin (RM) (%	12.4	11.7	12.9	10.0	12.1	11.5	11.3	10.0	10.9	10.0	10.0	10.0	10.0

Low Natural Gas Price Escalation
(0.3% till 2006, -0.3% thereafter)
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	4.7	9.5	14.4	19.8	25.3	30.8	36.4	42.0	47.6	55.9	70.5	88.1	110.4
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2						259.9	424.3	555.6	553.9	726.1	991.3	1,238.5	1,219.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT												42.3	42.3
	OWC Pump Storage													
	Total	**4.7**	**9.5**	**14.4**	**19.8**	**25.3**	**290.7**	**460.6**	**597.5**	**601.5**	**782.0**	**1,061.8**	**1,368.9**	**1,371.7**
	DSM Programs	0.4	0.8	1.2	1.6	2.1	2.5	3.0	3.4	3.9	4.6	5.8	7.2	8.8
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.8**	**1.2**	**1.6**	**2.1**	**2.5**	**3.0**	**3.4**	**3.9**	**4.6**	**5.8**	**7.2**	**8.8**
	DSM Programs	6.8	14.1	22.1	30.7	39.2	48.0	56.9	65.9	75.3	89.8	115.0	145.5	185.1
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													413.7
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**6.8**	**14.1**	**22.1**	**30.7**	**39.2**	**48.0**	**56.9**	**65.9**	**75.3**	**89.8**	**115.0**	**145.5**	**598.8**
	DSM Programs	2.0	4.0	6.0	8.3	10.7	13.0	15.4	17.8	20.2	23.8	29.7	36.6	45.3
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.0**	**4.0**	**6.0**	**8.3**	**10.7**	**13.0**	**15.4**	**17.8**	**20.2**	**23.8**	**29.7**	**36.6**	**45.3**
	DSM Programs	13.8	28.4	43.7	60.4	77.2	94.4	111.7	129.1	146.9	174.1	221.0	277.3	349.6
	Short Term Cap Purch				0.0							0.1	0.4	0.5
T	Cogeneration						259.9	424.3	555.6	553.9	726.1	991.3	1,238.5	1,632.8
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle												42.3	42.3
	Storage													
	Total	**13.8**	**28.4**	**43.7**	**60.5**	**77.2**	**354.3**	**535.9**	**684.7**	**700.8**	**900.1**	**1,212.4**	**1,558.5**	**2,025.1**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	881.6	978.3	1,097.2	1,124.8	1,166.9	1,251.0	1,269.4	1,277.7	1,324.0	1,269.1	1,303.8	1,207.6	1,200.4
E	**DSM Programs**	(13.8)	(28.4)	(43.7)	(60.4)	(77.2)	(94.3)	(111.7)	(129.1)	(146.9)	(174.1)	(221.0)	(277.3)	(349.6)
M	**Total Requirements**	8,988.0	9,015.0	8,961.3	8,865.4	8,777.8	8,854.5	8,979.0	9,039.1	9,020.6	9,035.5	9,317.5	9,513.8	9,867.5
	Existing Generation	7,774.8	7,708.8	7,659.9	7,571.9	7,704.2	7,740.5	7,725.5	7,658.5	7,654.1	7,484.7	7,502.8	7,405.1	7,400.4
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.8	336.3	336.4	329.7	360.9	358.1	343.6	359.1	346.7	358.9	376.3	383.6	382.9
R	**New Resources**						259.9	424.3	555.6	553.9	726.1	991.4	1,281.2	1,675.6
	Total Resources	8,987.9	9,015.0	8,961.3	8,865.3	8,777.8	8,854.6	8,979.0	9,039.0	9,020.5	9,035.5	9,317.5	9,513.8	9,867.5

Low Natural Gas Price Escalation
(0.3% till 2006, -0.3% thereafter)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	14	28	44	60	77	94	112	129	147	174	221	277	350
			After Conservation													
			System Load (MWa)	5,712	5,764	5,860	5,996	6,101	6,227	6,365	6,527	6,625	6,732	7,143	7,543	7,948
	0.66		Energy Sales (MWa)	5,160	5,259	5,359	5,469	5,581	5,697	5,814	5,924	5,998	6,054	6,370	6,705	7,098
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,010	8,175	8,402	8,668	9,011	9,309	9,557	9,808	10,095	10,311	11,398	12,416	14,276
			Net Conservation Assets ($M)	14	29	43	58	71	84	96	108	121	136	168	193	222
			Utility Cost													
45,860	3.23	Nominal	Operating Revenues ($M)	2,146	2,192	2,285	2,363	2,457	2,458	2,567	2,685	2,818	2,936	3,282	3,809	4,414
	0.23	Real		2,146	2,128	2,154	2,163	2,183	2,120	2,150	2,183	2,225	2,250	2,302	2,445	2,517
	2.56	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.3	50.3	49.3	50.4	51.7	53.6	55.4	58.8	64.8	71.0
	-0.43	Real		47.5	46.2	45.9	45.1	44.7	42.5	42.2	42.1	42.3	42.4	41.3	41.6	40.5
		Nominal	Average Customer Bill ($)	1,602	1,615	1,656	1,682	1,720	1,693	1,739	1,789	1,849	1,897	2,024	2,253	2,459
		Real		1,602	1,568	1,561	1,539	1,528	1,461	1,456	1,455	1,459	1,454	1,419	1,446	1,402
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.5	-2.2	-2.5	-3.3	-4.9	-7.0	-9.5	-12.8	-16.5	-21.3	-40.1	-69.2	-119.2
			Levelized (20-year at 7.9%)	-0.1	-0.4	-0.6	-1.0	-1.5	-2.2	-3.1	-4.4	-6.1	-8.2	-17.6	-34.4	-72.0
			Energy Svc Charge ($M)	1.3	2.8	4.4	6.1	8.0	9.9	11.9	14.2	15.6	17.2	21.0	24.6	28.6
45,338	3.133	Nominal	Total Resource Cost ($M)	2,147	2,194	2,289	2,368	2,463	2,466	2,575	2,695	2,828	2,945	3,285	3,799	4,371
	0.13	Real		2,147	2,130	2,157	2,167	2,189	2,127	2,157	2,191	2,232	2,257	2,304	2,438	2,493
	2.36	Nominal	Cost in mills/kWh	47.4	47.4	48.4	48.9	49.8	48.7	49.7	50.9	52.6	54.1	57.1	62.3	67.3
	-0.62	Real		47.4	46.0	45.6	44.8	44.2	42.0	41.6	41.4	41.6	41.5	40.0	40.0	38.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.70**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.98**

Low Natural Gas Price Escalation
(0.3% till 2006, -0.3% thereafter)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,038	50,502	51,321	52,088	53,010	54,112	55,318	56,741	57,577	58,522	62,122	65,624	69,170
	MWa	5,712	5,765	5,859	5,946	6,051	6,177	6,315	6,477	6,573	6,681	7,092	7,491	7,896
	Total Annual Emissions (1000 Tons)													
0.55%	CO2	56,596	56,880	56,933	57,229	57,264	56,683	57,065	57,229	57,562	57,687	59,113	61,353	62,757
-0.13%	NOx	132.6	131.6	130.4	129.5	131.4	131.2	130.9	129.6	129.5	127.7	128.1	129.2	129.2
0.00%	TSP	11.8	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.6	11.7	11.8	11.8
	Annual System Emission Rates (Pounds/MWh)													
-1.15%	CO2	2,262	2,253	2,219	2,197	2,161	2,095	2,063	2,017	1,999	1,971	1,903	1,870	1,815
-1.82%	NOx	5.30	5.21	5.08	4.97	4.96	4.85	4.73	4.57	4.50	4.37	4.12	3.94	3.74
-1.69%	TSP	0.47	0.46	0.46	0.45	0.44	0.43	0.42	0.41	0.40	0.40	0.38	0.36	0.34
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.58	98.08	97.14	95.51	92.61	91.20	89.17	88.39	87.15	84.13	82.66	80.22
	NOx	100	98.32	95.88	93.85	93.55	91.50	89.30	86.17	84.87	82.38	77.81	74.28	70.51
	TSP	100	98.48	96.52	94.92	93.84	91.54	89.55	87.08	85.82	84.11	79.68	76.04	72.35

20 Year Emissions (1000 Tons)	Average	Total
CO2	58,889	1,177,782
NOx	130	2,591
TSP	12	234

High Natural Gas Price Escalation
(4.5% till 2006, 2.4% thereafter)
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				9.8				89.7		192.1	345.5	500.0	500.0
	DSM Programs	7.3	7.5	7.5	8.2	8.4	8.3	8.6	8.7	8.7	13.5	22.3	26.4	33.1
	OWC Geothermal													
O	OWC Cogen 1													202.1
W	OWC Cogen 2						140.0	187.8	137.2		73.6	223.6	440.6	103.8
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													146.5
	OWC Pump Storage													
	Total	**7.3**	**7.5**	**7.5**	**8.2**	**8.4**	**148.3**	**196.4**	**145.9**	**8.7**	**87.1**	**245.9**	**467.0**	**485.5**
	DSM Programs	0.6	0.5	0.6	0.5	0.7	0.6	0.7	0.6	0.7	1.0	2.3	2.8	3.5
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.7**	**0.6**	**0.7**	**0.6**	**0.7**	**1.0**	**2.3**	**2.8**	**3.5**
	DSM Programs	11.5	11.2	11.9	13.4	13.3	14.1	14.0	14.2	15.0	23.0	40.6	49.3	64.1
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4													
	Utah IGCC CT													
	Utah PC Hunter 4													120.2
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													
	Utah Wyo/Ut Tran L													15.2
	Total	**11.5**	**11.2**	**11.9**	**13.4**	**13.3**	**14.1**	**14.0**	**14.2**	**15.0**	**23.0**	**40.6**	**49.3**	**199.5**
	DSM Programs	2.8	2.8	2.9	2.8	3.3	3.4	3.4	3.5	3.4	5.2	8.4	9.6	12.0
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.9**	**2.8**	**3.3**	**3.4**	**3.4**	**3.5**	**3.4**	**5.2**	**8.4**	**9.6**	**12.0**
T	DSM Programs	22.2	22.0	22.9	24.9	25.7	26.4	26.7	27.0	27.8	42.7	73.6	88.1	112.7
O	Short Term Cap Purch				9.8				89.7		192.1	345.5	500.0	500.0
T	Cogeneration						140.0	187.8	137.2		73.6	223.6	440.6	305.9
A	Combined Cycle CT													
L	All Others													281.9
	Total	**22.2**	**22.0**	**22.9**	**34.7**	**25.7**	**166.4**	**214.5**	**253.9**	**27.8**	**308.4**	**642.7**	**1,028.7**	**1,200.5**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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)	(44)	(67)	(92)	(118)	(144)	(171)	(198)	(226)	(268)	(342)	(430)	(543)
T	**Total Requirements**	**9,873**	**10,007**	**9,857**	**9,974**	**9,755**	**9,801**	**9,958**	**9,980**	**9,902**	**10,038**	**10,346**	**10,761**	**11,262**
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	9,511
	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				10				90		192	346	500	500
&	New Resources						140	328	465	465	539	763	1,203	1,791
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,972**	**10,948**	**10,818**	**10,991**	**10,979**	**10,893**	**11,042**	**11,382**	**11,838**	**12,389**
	Reserves	1,223	1,179	1,274	997	1,193	1,017	1,032	998	990	1,004	1,034	1,076	1,126
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.4	10.4	10.0	10.0	10.0	10.0	10.0	10.0

High Natural Gas Price Escalation
(4.5% till 2006, 2.4% thereafter)
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.7	11.6	17.5	23.9	30.4	36.9	43.7	50.5	57.4	68.1	85.8	106.8	133.3
	OWC Geothermal													
O	OWC Cogen 1													173.2
W	OWC Cogen 2						125.3	293.5	416.3	395.7	458.3	648.7	1,023.7	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													30.9
	OWC Pump Storage													
	Total	**5.7**	**11.6**	**17.5**	**23.9**	**30.4**	**162.3**	**337.2**	**466.8**	**453.1**	**526.4**	**734.5**	**1,130.5**	**1,449.4**
	DSM Programs	0.5	0.9	1.3	1.8	2.3	2.8	3.3	3.9	4.4	5.2	6.8	8.8	11.2
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.3**	**2.8**	**3.3**	**3.9**	**4.4**	**5.2**	**6.8**	**8.8**	**11.2**
	DSM Programs	7.8	15.4	23.5	32.8	42.1	52.0	61.8	71.8	82.3	98.5	127.4	162.9	209.4
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4													
	Utah IGCC CT													
	Utah PC Hunter 4													110.1
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													
	Utah Wyo/Ut Tran L													14.2
	Total	**7.8**	**15.4**	**23.5**	**32.8**	**42.1**	**52.0**	**61.8**	**71.8**	**82.3**	**98.5**	**127.4**	**162.9**	**333.8**
	DSM Programs	2.3	4.6	6.9	9.2	11.9	14.7	17.5	20.3	23.2	27.5	34.9	43.6	55.1
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.3**	**4.6**	**6.9**	**9.2**	**11.9**	**14.7**	**17.5**	**20.3**	**23.2**	**27.5**	**34.9**	**43.6**	**55.1**
	DSM Programs	16.3	32.4	49.3	67.7	86.7	106.4	126.3	146.5	167.2	199.3	254.9	322.2	409.0
	Short Term Cap Purch				0.0				0.1		0.2	0.4	0.5	0.4
T	Cogeneration						125.3	293.5	416.3	395.7	458.3	648.7	1,023.7	1,285.2
O	Combined Cycle CT													
T	Coal													110.1
A	Transmission													14.2
L	Simple Cycle													30.9
	Storage													
	Total	**16.3**	**32.4**	**49.3**	**67.7**	**86.7**	**231.7**	**419.8**	**562.9**	**563.0**	**657.8**	**904.0**	**1,346.3**	**1,849.8**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.5	988.7	1,123.3	1,166.0	1,214.1	1,248.5	1,299.6	1,305.0	1,334.5	1,263.6	1,274.3	1,238.6	1,263.6
E	**DSM Programs**	(16.3)	(32.4)	(49.3)	(67.7)	(86.7)	(106.4)	(126.3)	(146.5)	(167.2)	(199.2)	(254.9)	(322.2)	(409.0)
M	**Total Requirements**	8,986.4	9,021.3	8,981.9	8,899.3	8,815.4	8,839.9	8,994.5	9,049.0	9,010.8	9,004.9	9,254.1	9,499.9	9,871.2
	Existing Generation	7,773.7	7,739.0	7,696.0	7,624.3	7,769.6	7,883.9	7,896.7	7,833.6	7,819.4	7,770.6	7,813.7	7,685.6	7,674.9
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.3	312.4	320.9	311.3	333.2	334.7	318.7	333.1	329.8	309.9	344.3	346.3	346.9
R	**New Resources**						125.3	293.5	416.4	395.7	458.5	649.0	1,024.2	1,440.8
	Total Resources	8,986.4	9,021.4	8,981.9	8,899.3	8,815.4	8,839.9	8,994.5	9,049.0	9,010.8	9,004.9	9,254.1	9,499.9	9,871.2

High Natural Gas Price Escalation
(4.5% till 2006, 2.4% thereafter)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	32	49	68	87	106	126	146	167	199	255	322	409
			After Conservation													
			System Load (MWa)	5,709	5,760	5,854	5,989	6,092	6,215	6,350	6,510	6,604	6,707	7,109	7,498	7,889
	0.64		Energy Sales (MWa)	5,158	5,255	5,354	5,462	5,572	5,686	5,801	5,908	5,979	6,031	6,339	6,664	7,043
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,179	8,403	8,627	8,920	9,230	9,481	9,686	9,935	10,139	11,177	12,448	14,521
			Net Conservation Assets ($M)	17	33	50	66	80	94	108	122	136	154	193	224	260
			Utility Cost													
45,592	3.22	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,280	2,353	2,443	2,442	2,532	2,667	2,777	2,933	3,267	3,756	4,365
	0.21	Real		2,146	2,126	2,149	2,154	2,170	2,106	2,121	2,168	2,192	2,248	2,292	2,411	2,489
	2.57	Nominal	Cost in mills/kWh	47.5	47.6	48.6	49.2	50.0	49.0	49.8	51.5	53.0	55.5	58.8	64.4	70.8
	-0.42	Real		47.5	46.2	45.8	45.0	44.5	42.3	41.7	41.9	41.9	42.5	41.3	41.3	40.4
		Nominal	Average Customer Bill ($)	1,602	1,613	1,653	1,675	1,710	1,682	1,715	1,777	1,821	1,894	2,015	2,223	2,431
		Real		1,602	1,566	1,558	1,533	1,520	1,451	1,436	1,445	1,438	1,452	1,413	1,427	1,387
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.4	-2.8	-3.7	-5.4	-7.7	-10.6	-14.3	-18.5	-24.1	-45.9	-80.6	-141.0
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-4.9	-6.8	-9.3	-19.9	-39.3	-83.3
			Energy Svc Charge ($M)	1.6	3.3	5.1	7.1	9.1	11.2	13.5	16.1	17.5	19.3	23.7	28.1	33.1
45,055	3.12	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,285	2,359	2,450	2,451	2,542	2,678	2,787	2,943	3,271	3,745	4,315
	0.12	Real		2,147	2,129	2,154	2,159	2,177	2,114	2,129	2,177	2,200	2,255	2,294	2,404	2,461
	2.35	Nominal	Cost in mills/kWh	47.4	47.4	48.3	48.8	49.5	48.4	49.0	50.6	51.9	54.1	56.8	61.4	66.4
	-0.63	Real		47.4	46.0	45.5	44.6	44.0	41.7	41.1	41.1	41.0	41.4	39.8	39.4	37.9

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.68**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.73**

High Natural Gas Price Escalation
(4.5% till 2006, 2.4% thereafter)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,016	50,466	51,273	52,025	52,926	54,006	55,190	56,590	57,400	58,301	61,825	65,231	68,649
	MWa	5,710	5,761	5,853	5,939	6,042	6,165	6,300	6,460	6,552	6,655	7,058	7,446	7,837
	Total Annual Emissions (1000 Tons)													
0.71%	CO2	56,580	57,041	57,124	57,513	57,612	57,490	57,942	58,189	58,461	59,317	60,813	62,718	64,703
0.10%	NOx	132.6	132.2	131.1	130.6	132.7	134.0	134.0	132.9	132.7	133.3	134.0	134.3	135.1
0.16%	TSP	11.8	11.8	11.7	11.8	11.8	11.9	11.9	11.9	11.9	12.0	12.0	12.0	12.2
	Annual System Emission Rates (Pounds/MWh)													
-0.96%	CO2	2,262	2,261	2,228	2,211	2,177	2,129	2,100	2,057	2,037	2,035	1,967	1,923	1,885
-1.55%	NOx	5.30	5.24	5.11	5.02	5.02	4.96	4.86	4.70	4.62	4.57	4.33	4.12	3.94
-1.49%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.92	98.49	97.72	96.23	94.10	92.81	90.90	90.03	89.94	86.95	84.99	83.32
	NOx	100	98.82	96.48	94.71	94.61	93.60	91.61	88.62	87.20	86.29	81.76	77.68	74.25
	TSP	100	98.82	96.86	95.76	94.70	93.24	91.33	89.09	87.79	87.05	82.32	78.24	75.13

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,015	1,200,301
NOx	133	2,669
TSP	12	239

Natural Gas Price Doubles by 2006
(8.0% till 2006, 2.4% thereafter)
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				2.6				199.1	108.1	307.4	445.4	500.0	500.0
	DSM Programs	7.9	8.0	8.3	8.6	8.9	9.0	9.1	9.2	9.1	13.5	22.4	26.5	33.0
	OWC Geothermal													
O	OWC Cogen 1						51.7	150.4	0.0					
W	OWC Cogen 2						42.0	37.5	63.2		65.2	239.3	179.4	140.5
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													0.7
	OWC Pump Storage													78.3
	Total	**7.9**	**8.0**	**8.3**	**8.6**	**8.9**	**102.7**	**197.0**	**72.4**	**9.1**	**78.7**	**261.7**	**205.9**	**252.5**
	DSM Programs	0.7	0.6	0.6	0.6	0.7	0.6	0.7	0.9	1.0	1.4	2.4	2.9	3.5
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans										34.7	104.2	33.3	5.7
O	Idaho Htr/Id Trans L													
	Total	**0.7**	**0.6**	**0.6**	**0.6**	**0.7**	**0.6**	**0.7**	**0.9**	**1.0**	**36.1**	**106.6**	**36.2**	**9.2**
	DSM Programs	12.2	11.8	13.0	13.8	13.5	14.3	14.2	14.4	15.4	23.9	41.1	49.5	64.1
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4													
	Utah IGCC CT													
	Utah PC Hunter 4												361.0	39.0
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													49.9
	Utah Wyo/Ut Tran L													10.7
	Total	**12.2**	**11.8**	**13.0**	**13.8**	**13.5**	**14.3**	**14.2**	**14.4**	**15.4**	**23.9**	**41.1**	**410.5**	**163.7**
	DSM Programs	2.8	3.2	3.3	3.2	3.4	3.4	3.4	3.4	3.5	5.2	8.5	9.5	12.0
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													264.0
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**3.2**	**3.3**	**3.2**	**3.4**	**3.4**	**3.4**	**3.4**	**3.5**	**5.2**	**8.5**	**9.5**	**276.0**
T	DSM Programs	23.6	23.6	25.2	26.2	26.5	27.3	27.4	27.9	29.0	44.0	74.4	88.4	112.6
O	Short Term Cap Purch				2.6				199.1	108.1	307.4	445.4	500.0	500.0
T	Cogeneration						93.7	187.9	63.2		65.2	239.3	179.4	140.5
A	Combined Cycle CT													
L	All Others										34.7	104.2	394.3	448.3
	Total	**23.6**	**23.6**	**25.2**	**28.8**	**26.5**	**121.0**	**215.3**	**290.2**	**137.1**	**451.3**	**863.3**	**1,162.1**	**1,201.4**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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	(24)	(47)	(72)	(99)	(125)	(152)	(180)	(208)	(237)	(281)	(355)	(443)	(556)
T	**Total Requirements**	**9,871**	**10,004**	**9,852**	**9,967**	**9,748**	**9,793**	**9,949**	**9,970**	**9,891**	**10,025**	**10,333**	**10,748**	**11,249**
E														
M	Existing Generation	9,949	9,994	10,010	9,842	9,848	9,855	9,855	9,766	9,770	9,618	9,525	9,353	9,336
	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				3				199	108	307	445	500	500
&	New Resources						94	282	345	345	445	789	1,362	1,951
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,965**	**10,948**	**10,772**	**10,945**	**10,968**	**10,881**	**11,028**	**11,367**	**11,823**	**12,374**
	Reserves	1,224	1,182	1,280	997	1,201	979	995	997	989	1,002	1,033	1,075	1,125
	Reserve Margin (RM) (%	12.4	11.8	13.0	10.0	12.3	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Natural Gas Price Doubles by 2006
(8.0% till 2006, 2.4% thereafter)
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	6.1	12.2	18.7	25.3	32.3	39.4	46.6	53.9	61.1	71.8	89.6	110.7	137.2
	OWC Geothermal													
O	OWC Cogen 1						51.2	200.1	200.1	182.2	173.2	173.2	173.2	172.0
W	OWC Cogen 2						37.7	67.7	121.4	121.4	176.9	380.6	533.3	652.9
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													0.1
	OWC Pump Storage													19.4
	Total	**6.1**	**12.2**	**18.7**	**25.3**	**32.3**	**128.3**	**314.4**	**375.4**	**364.7**	**421.9**	**643.4**	**817.1**	**981.6**
	DSM Programs	0.5	1.0	1.6	2.1	2.6	3.1	3.7	4.3	5.0	6.0	7.6	9.6	12.0
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans										31.6	126.1	156.4	161.5
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**1.0**	**1.6**	**2.1**	**2.6**	**3.1**	**3.7**	**4.3**	**5.0**	**37.5**	**133.8**	**165.9**	**173.5**
	DSM Programs	8.4	16.7	25.7	35.3	44.8	54.8	64.8	74.9	85.9	102.9	132.4	168.2	214.7
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4													
	Utah IGCC CT													
	Utah PC Hunter 4												330.9	363.0
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													12.4
	Utah Wyo/Ut Tran L													10.1
	Total	**8.4**	**16.7**	**25.7**	**35.3**	**44.8**	**54.8**	**64.8**	**74.9**	**85.9**	**102.9**	**132.4**	**499.0**	**600.1**
	DSM Programs	2.3	4.9	7.7	10.4	13.3	16.2	19.2	22.2	25.3	29.9	37.6	46.6	58.1
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													241.9
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.3**	**4.9**	**7.7**	**10.4**	**13.3**	**16.2**	**19.2**	**22.2**	**25.3**	**29.9**	**37.6**	**46.6**	**300.0**
	DSM Programs	17.3	34.9	53.6	73.1	92.9	113.5	134.2	155.2	177.2	210.6	267.2	335.0	422.0
	Short Term Cap Purch								0.2	0.1	0.2	0.3	0.4	0.4
T	Cogeneration						88.9	267.8	321.6	303.7	350.1	553.8	706.4	824.9
O	Combined Cycle CT													
T	Coal												330.9	604.9
A	Transmission										31.6	126.1	156.4	171.5
L	Simple Cycle													0.1
	Storage													31.8
	Total	**17.3**	**34.9**	**53.6**	**73.1**	**92.9**	**202.3**	**402.0**	**477.0**	**481.0**	**592.5**	**947.4**	**1,529.1**	**2,055.6**
S	Native Load	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	Pump Storage/Peak Ret	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	297.4
S	Long Term Sales	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	Short Term Sales	882.9	1,014.0	1,176.1	1,218.3	1,247.3	1,260.1	1,314.2	1,300.4	1,351.2	1,281.9	1,282.2	1,300.1	1,318.3
E	DSM Programs	(17.3)	(34.9)	(53.6)	(73.1)	(92.9)	(113.5)	(134.2)	(155.2)	(177.2)	(210.6)	(267.2)	(335.0)	(421.9)
M	Total Requirements	8,985.8	9,044.2	9,030.4	8,946.1	8,842.4	8,844.4	9,001.2	9,035.7	9,017.5	9,011.8	9,249.7	9,548.6	9,953.9
	Existing Generation	7,773.3	7,772.6	7,769.8	7,696.7	7,819.6	7,940.6	7,947.3	7,939.8	7,964.0	7,886.3	7,827.5	7,627.7	7,614.6
L	Long Term Purchases	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	Short Term Purchases	343.2	301.6	295.6	285.7	310.1	318.9	300.6	308.2	283.8	277.8	294.9	282.9	297.0
R	New Resources						88.8	267.8	321.8	303.8	381.9	680.2	1,194.0	1,633.7
	Total Resources	8,985.8	9,044.2	9,030.4	8,946.1	8,842.4	8,844.5	9,001.2	9,035.7	9,017.4	9,011.8	9,249.7	9,548.6	9,953.9

Natural Gas Price Doubles by 2006
(8.0% till 2006, 2.4% thereafter)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	17	35	54	73	93	113	134	155	177	211	267	335	422
			After Conservation													
			System Load (MWa)	5,708	5,758	5,850	5,983	6,086	6,208	6,342	6,501	6,594	6,696	7,097	7,485	7,876
	0.64		Energy Sales (MWa)	5,157	5,253	5,350	5,457	5,566	5,679	5,793	5,900	5,970	6,020	6,328	6,652	7,031
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,013	8,181	8,405	8,632	8,959	9,295	9,519	9,717	9,969	10,196	11,484	13,024	15,314
			Net Conservation Assets ($M)	17	35	52	69	85	100	114	129	144	163	204	236	273
			Utility Cost													
44,957	3.15	Nominal	**Operating Revenues ($M)**	2,145	2,188	2,276	2,344	2,427	2,420	2,502	2,667	2,750	2,901	3,223	3,645	4,280
	0.15	Real		2,145	2,124	2,146	2,145	2,156	2,087	2,096	2,168	2,171	2,223	2,261	2,340	2,441
	2.50	Nominal	Cost in mills/kWh	47.5	47.5	48.6	49.0	49.8	48.6	49.3	51.6	52.6	55.0	58.2	62.6	69.5
	-0.49	Real		47.5	46.2	45.8	44.9	44.2	42.0	41.3	42.0	41.5	42.2	40.8	40.2	39.6
		Nominal	Average Customer Bill ($)	1,602	1,612	1,650	1,668	1,699	1,667	1,695	1,777	1,804	1,874	1,988	2,157	2,384
		Real		1,602	1,565	1,555	1,527	1,510	1,438	1,420	1,445	1,424	1,436	1,394	1,384	1,360
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.9	-3.7	-5.5	-7.9	-11.0	-14.9	-19.5	-25.5	-48.5	-84.9	-147.1
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.6	-5.1	-7.0	-9.6	-20.8	-41.4	-87.5
			Energy Svc Charge ($M)	1.7	3.5	5.4	7.5	9.6	11.9	14.3	17.0	18.5	20.4	25.1	29.7	34.7
44,415	3.049	Nominal	**Total Resource Cost ($M)**	2,147	2,191	2,281	2,350	2,435	2,429	2,513	2,679	2,762	2,912	3,228	3,633	4,228
	0.05	Real		2,147	2,127	2,150	2,151	2,163	2,096	2,105	2,178	2,180	2,231	2,264	2,332	2,411
	2.28	Nominal	Cost in mills/kWh	47.4	47.3	48.2	48.6	49.2	47.9	48.5	50.6	51.4	53.5	56.1	59.6	65.1
	-0.70	Real		47.4	45.9	45.5	44.4	43.7	41.4	40.6	41.1	40.6	41.0	39.3	38.3	37.1

Notes:

1) $M = millions of dollars
2) General Inflation Rate is 3.0% annually
3) 50-year Real Levelized Utility Cost in mills/kWh = **41.14**
4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.17**

Natural Gas Price Doubles by 2006
(8.0% till 2006, 2.4% thereafter)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,007	50,444	51,235	51,977	52,871	53,944	55,121	56,513	57,312	58,202	61,717	65,119	68,894
	MWa	5,709	5,758	5,849	5,933	6,036	6,158	6,292	6,451	6,542	6,644	7,045	7,434	7,865
	Total Annual Emissions (1000 Tons)													
1.00%	CO2	56,574	57,228	57,539	57,919	57,859	57,687	58,087	58,625	59,119	59,989	61,472	64,968	68,327
0.25%	NOx	132.6	132.9	132.6	132.1	133.7	134.9	135.0	134.9	135.4	136.1	136.7	137.5	139.0
0.33%	TSP	11.8	11.8	11.8	11.8	11.9	11.9	12.0	12.0	12.0	12.1	12.1	12.3	12.6
	Annual System Emission Rates (Pounds/MWh)													
-0.69%	CO2	2,263	2,269	2,246	2,229	2,189	2,139	2,108	2,075	2,063	2,061	1,992	1,995	1,984
-1.43%	NOx	5.30	5.27	5.18	5.08	5.06	5.00	4.90	4.77	4.72	4.68	4.43	4.22	4.04
-1.35%	TSP	0.47	0.47	0.46	0.46	0.45	0.44	0.43	0.42	0.42	0.42	0.39	0.38	0.36
	Emission Rates as Percent of 1997 Base													
	CO2	100	100.28	99.27	98.50	96.73	94.53	93.15	91.70	91.18	91.11	88.04	88.19	87.67
	NOx	100	99.36	97.64	95.85	95.38	94.32	92.40	90.04	89.10	88.20	83.53	79.68	76.13
	TSP	100	99.22	97.68	96.57	95.49	93.82	92.07	89.97	89.01	88.06	83.34	80.33	77.28

20 Year Emissions (1000 Tons)	Average	Total
CO2	61,162	1,223,238
NOx	136	2,715
TSP	12	242

Natural Gas Price Triples by 2006
(13.0% till 2006, 2.4% thereafter)
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch							74.5	326.8	118.8	193.2	263.9	500.0	500.0
	DSM Programs	8.4	8.7	8.8	8.9	9.0	9.0	9.1	9.4	9.4	14.0	23.1	27.4	34.2
	OWC Geothermal													
O	OWC Cogen 1						89.1	113.0						
W	OWC Cogen 2													
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													11.0
	Total	**8.4**	**8.7**	**8.8**	**8.9**	**9.0**	**98.1**	**122.1**	**9.4**	**9.4**	**14.0**	**23.1**	**27.4**	**45.2**
	DSM Programs	0.7	0.6	0.6	0.6	0.7	0.9	0.9	1.0	0.9	1.5	2.4	2.9	3.5
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans							44.2	36.5		128.5	105.3	68.6	49.4
O	Idaho Htr/Id Trans L													
	Total	**0.7**	**0.6**	**0.6**	**0.6**	**0.7**	**0.9**	**45.1**	**37.5**	**0.9**	**130.0**	**107.7**	**71.5**	**52.9**
	DSM Programs	12.6	12.2	13.1	13.9	13.5	14.7	14.7	14.8	15.6	23.9	41.2	49.7	64.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4								9.5	116.5	136.0			
	Utah IGCC CT													
	Utah PC Hunter 4										54.5	246.3	99.2	
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													30.7
	Utah Wyo/Ut Tran L													201.4
	Total	**12.6**	**12.2**	**13.1**	**13.9**	**13.5**	**14.7**	**14.7**	**24.3**	**132.1**	**214.4**	**287.5**	**148.9**	**296.3**
	DSM Programs	3.2	3.2	3.3	3.2	3.4	3.4	3.4	3.5	3.4	5.2	8.5	9.6	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2											59.4	204.6	
N	Wyo Coal $6.70/Ton												54.3	531.8
G	Wyo Simple Cycle CT													
	Total	**3.2**	**3.2**	**3.3**	**3.2**	**3.4**	**3.4**	**3.4**	**3.5**	**3.4**	**5.2**	**67.9**	**268.5**	**543.7**
T	DSM Programs	24.9	24.7	25.8	26.6	26.6	28.0	28.1	28.7	29.3	44.6	75.2	89.6	113.8
O	Short Term Cap Purch							74.5	326.8	118.8	193.2	263.9	500.0	500.0
T	Cogeneration						89.1	113.0						
A	Combined Cycle CT													
L	All Others							44.2	46.0	116.5	319.0	411.0	426.7	824.3
	Total	**24.9**	**24.7**	**25.8**	**26.6**	**26.6**	**117.1**	**259.8**	**401.5**	**264.6**	**556.8**	**750.1**	**1,016.3**	**1,438.1**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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	(25)	(50)	(75)	(102)	(129)	(157)	(185)	(213)	(243)	(287)	(363)	(452)	(566)
T	**Total Requirements**	**9,870**	**10,001**	**9,849**	**9,964**	**9,744**	**9,788**	**9,944**	**9,965**	**9,885**	**10,019**	**10,325**	**10,739**	**11,239**
E														
M	Existing Generation	9,949	9,994	10,010	9,842	9,848	9,855	9,810	9,685	9,689	9,442	9,348	9,140	8,886
	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							75	327	119	193	264	500	500
&	New Resources						89	247	292	409	728	1,139	1,565	2,390
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,962**	**10,948**	**10,767**	**10,940**	**10,962**	**10,875**	**11,021**	**11,359**	**11,813**	**12,363**
	Reserves	1,226	1,184	1,283	997	1,204	979	994	997	989	1,002	1,032	1,074	1,124
	Reserve Margin (RM) (%	12.4	11.8	13.0	10.0	12.4	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Natural Gas Price Triples by 2006
(13.0% till 2006, 2.4% thereafter)
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	6.6	13.3	20.1	27.1	34.1	41.3	48.5	56.0	63.5	74.6	93.1	115.1	142.6
	OWC Geothermal													
O	OWC Cogen 1						86.6	187.6	173.2	173.2	173.2	172.0	172.0	172.0
W	OWC Cogen 2													
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													2.7
	Total	**6.6**	**13.3**	**20.1**	**27.1**	**34.1**	**127.9**	**236.0**	**229.2**	**236.7**	**247.8**	**265.1**	**287.1**	**317.4**
	DSM Programs	0.5	1.0	1.6	2.1	2.6	3.2	3.9	4.5	5.2	6.2	7.8	9.8	12.2
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans							40.1	73.3	73.3	189.9	285.6	347.8	392.3
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**1.0**	**1.6**	**2.1**	**2.6**	**3.2**	**44.0**	**77.8**	**78.4**	**196.1**	**293.4**	**357.6**	**404.6**
	DSM Programs	8.7	17.2	26.3	35.9	45.4	55.8	66.3	76.9	88.0	105.0	134.6	170.6	217.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4								8.6	114.3	237.6	237.6	237.6	237.6
	Utah IGCC CT													
	Utah PC Hunter 4										50.0	275.6	366.6	366.6
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													7.6
	Utah Wyo/Ut Tran L													188.7
	Total	**8.7**	**17.2**	**26.3**	**35.9**	**45.4**	**55.8**	**66.3**	**85.5**	**202.3**	**392.6**	**647.9**	**774.7**	**1,017.6**
	DSM Programs	2.7	5.4	8.1	10.8	13.7	16.6	19.6	22.6	25.7	30.3	38.0	47.1	58.5
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2											54.4	241.9	241.9
N	Wyo Coal $6.70/Ton												49.8	537.4
G	Wyo Simple Cycle CT													
	Total	**2.7**	**5.4**	**8.1**	**10.8**	**13.7**	**16.6**	**19.6**	**22.6**	**25.7**	**30.3**	**92.4**	**338.8**	**837.8**
	DSM Programs	18.4	36.8	56.0	75.8	95.8	116.9	138.2	160.0	182.3	216.1	273.6	342.4	430.5
	Short Term Cap Purch							0.1	0.2	0.1	0.1	0.1	0.3	
T	Cogeneration						86.6	187.6	173.2	173.2	173.2	172.0	172.0	172.0
O	Combined Cycle CT													
T	Coal								8.6	114.3	287.6	567.7	895.9	1,383.5
A	Transmission							40.1	73.3	73.3	189.9	285.6	347.8	581.0
L	Simple Cycle													
	Storage													10.4
	Total	**18.4**	**36.8**	**56.0**	**75.8**	**95.8**	**203.5**	**366.0**	**415.2**	**543.1**	**866.9**	**1,299.0**	**1,758.4**	**2,577.3**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	269.8
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	883.3	1,027.8	1,204.3	1,249.3	1,314.1	1,289.0	1,303.0	1,246.9	1,389.0	1,435.9	1,477.5	1,386.8	1,381.9
E	**DSM Programs**	(18.4)	(36.8)	(56.0)	(75.8)	(95.8)	(116.9)	(138.2)	(160.0)	(182.3)	(216.1)	(273.6)	(342.4)	(430.5)
M	**Total Requirements**	8,985.1	9,056.1	9,056.2	8,974.4	8,906.4	8,870.0	8,986.0	8,977.4	9,050.2	9,160.2	9,438.7	9,627.9	9,981.4
	Existing Generation	7,772.7	7,792.0	7,811.7	7,750.4	7,902.3	8,020.4	8,017.9	8,007.2	8,003.6	7,827.6	7,739.5	7,523.4	7,238.1
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	714.0	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.0	294.1	279.4	260.3	290.1	266.9	254.7	249.1	220.0	215.9	226.7	244.7	187.8
R	**New Resources**						86.6	227.8	255.3	360.8	650.8	1,025.4	1,416.0	2,146.8
	Total Resources	8,985.1	9,056.1	9,056.1	8,974.4	8,906.4	8,870.0	8,986.0	8,977.4	9,050.2	9,160.2	9,438.7	9,627.9	9,981.4

Natural Gas Price Triples by 2006
(13.0% till 2006, 2.4% thereafter)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	18	37	56	76	96	117	138	160	182	216	274	342	431
			After Conservation													
			System Load (MWa)	5,707	5,756	5,848	5,981	6,083	6,205	6,338	6,497	6,589	6,690	7,091	7,478	7,867
	0.64		Energy Sales (MWa)	5,156	5,251	5,347	5,455	5,564	5,676	5,790	5,896	5,965	6,015	6,322	6,645	7,023
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,014	8,183	8,410	8,648	8,955	9,258	9,594	10,025	10,450	10,786	12,249	13,840	16,599
			Net Conservation Assets ($M)	18	37	55	72	88	103	117	133	149	168	209	242	279
			Utility Cost													
43,136	2.96	Nominal	**Operating Revenues ($M)**	2,145	2,185	2,269	2,331	2,404	2,383	2,466	2,609	2,641	2,752	3,032	3,523	4,017
	-0.04	Real		2,145	2,121	2,139	2,133	2,136	2,056	2,065	2,121	2,085	2,109	2,126	2,261	2,291
	2.31	Nominal	Cost in mills/kWh	47.5	47.5	48.5	48.8	49.3	47.9	48.6	50.5	50.6	52.2	54.8	60.5	65.3
	-0.67	Real		47.5	46.1	45.7	44.7	43.8	41.4	40.7	41.1	39.9	40.0	38.4	38.9	37.2
		Nominal	Average Customer Bill ($)	1,602	1,610	1,645	1,659	1,683	1,642	1,670	1,738	1,733	1,777	1,870	2,085	2,237
		Real		1,602	1,563	1,550	1,518	1,495	1,416	1,399	1,413	1,368	1,362	1,311	1,338	1,276
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.9	-3.7	-5.5	-7.9	-11.0	-14.8	-19.4	-25.4	-48.3	-84.7	-146.8
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.7	-2.5	-3.6	-5.1	-7.0	-9.6	-20.8	-41.3	-87.3
			Energy Svc Charge ($M)	1.8	3.7	5.7	7.8	10.1	12.4	14.9	17.7	19.2	21.1	25.9	30.6	35.7
42,602	2.85	Nominal	**Total Resource Cost ($M)**	2,147	2,188	2,274	2,338	2,412	2,393	2,477	2,621	2,653	2,763	3,037	3,512	3,965
	-0.15	Real		2,147	2,124	2,144	2,140	2,143	2,065	2,074	2,131	2,095	2,118	2,130	2,255	2,261
	2.08	Nominal	Cost in mills/kWh	47.4	47.3	48.1	48.3	48.7	47.2	47.8	49.5	49.4	50.8	52.7	57.6	61.0
	-0.89	Real		47.4	45.9	45.3	44.2	43.3	40.8	40.0	40.3	39.0	38.9	37.0	37.0	34.8

Notes:

1) $M = millions of dollars 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **39.51**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **37.57**

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Natural Gas Price Triples by 2006
(13.0% till 2006, 2.4% thereafter)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	49,997	50,428	51,214	51,953	52,847	53,914	55,086	56,471	57,268	58,153	61,662	65,053	68,578
	MWa	5,707	5,757	5,846	5,931	6,033	6,155	6,288	6,447	6,537	6,638	7,039	7,426	7,829
	Total Annual Emissions (1000 Tons)													
1.32%	CO2	56,566	57,337	57,781	58,224	58,346	58,139	58,740	59,451	60,171	61,661	64,625	68,567	72,606
0.37%	NOx	132.5	133.2	133.5	133.1	135.4	136.5	137.1	137.5	137.8	138.7	140.0	141.3	142.1
0.54%	TSP	11.8	11.8	11.8	11.9	12.1	12.1	12.1	12.2	12.2	12.3	12.5	12.7	13.1
	Annual System Emission Rates (Pounds/MWh)													
-0.35%	CO2	2,263	2,274	2,256	2,241	2,208	2,157	2,133	2,106	2,101	2,121	2,096	2,108	2,117
-1.29%	NOx	5.30	5.28	5.21	5.13	5.12	5.06	4.98	4.87	4.81	4.77	4.54	4.34	4.14
-1.12%	TSP	0.47	0.47	0.46	0.46	0.46	0.45	0.44	0.43	0.43	0.42	0.41	0.39	0.38
	Emission Rates as Percent of 1997 Base													
	CO2	100	100.50	99.72	99.06	97.59	95.31	94.25	93.05	92.87	93.72	92.64	93.16	93.58
	NOx	100	99.67	98.29	96.67	96.61	95.50	93.92	91.83	90.75	90.00	85.64	81.92	78.14
	TSP	100	99.57	98.05	97.02	96.88	94.89	93.36	91.25	90.36	89.89	86.06	82.99	80.75

20 Year Emissions (1000 Tons)	Average	Total
CO2	63,173	1,263,452
NOx	138	2,764
TSP	12	248

Natural Gas Price Jump 25% in 1998
(2.4% till 2006, 1.0% thereafter)
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				10.0				89.5		188.8	314.5	500.0	500.0
	DSM Programs	7.3	7.5	7.5	8.1	8.3	8.4	8.4	8.7	8.6	12.8	21.5	25.3	31.7
	OWC Geothermal													
O	OWC Cogen 1													202.1
W	OWC Cogen 2						103.7	197.5	165.1		77.7	254.0	413.4	95.2
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													61.6
	OWC Pump Storage													
	Total	**7.3**	**7.5**	**7.5**	**8.1**	**8.3**	**112.1**	**205.9**	**173.8**	**8.6**	**90.5**	**275.5**	**438.7**	**390.6**
	DSM Programs	0.6	0.5	0.6	0.5	0.7	0.6	0.7	0.6	0.7	1.0	1.7	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.7**	**0.6**	**0.7**	**0.6**	**0.7**	**1.0**	**1.7**	**1.9**	**2.4**
	DSM Programs	11.5	11.2	11.9	13.4	13.0	14.1	14.0	14.2	14.9	22.9	39.7	47.7	61.9
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													218.8
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**13.4**	**13.0**	**14.1**	**14.0**	**14.2**	**14.9**	**22.9**	**39.7**	**47.7**	**280.7**
	DSM Programs	2.8	2.8	2.9	2.8	2.9	3.4	3.4	3.5	3.4	5.2	8.4	9.5	12.0
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.9**	**2.8**	**2.9**	**3.4**	**3.4**	**3.5**	**3.4**	**5.2**	**8.4**	**9.5**	**12.0**
T	DSM Programs	22.2	22.0	22.9	24.8	24.9	26.5	26.5	27.0	27.6	41.9	71.3	84.4	108.0
O	Short Term Cap Purch				10.0				89.5		188.8	314.5	500.0	500.0
T	Cogeneration						103.7	197.5	165.1		77.7	254.0	413.4	516.1
A	Combined Cycle CT													
L	All Others													61.6
	Total	**22.2**	**22.0**	**22.9**	**34.8**	**24.9**	**130.2**	**224.0**	**281.6**	**27.6**	**308.4**	**639.8**	**997.8**	**1,185.7**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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)	(44)	(67)	(92)	(117)	(143)	(170)	(197)	(224)	(266)	(338)	(422)	(530)
T	**Total Requirements**	**9,873**	**10,007**	**9,857**	**9,974**	**9,756**	**9,802**	**9,959**	**9,981**	**9,904**	**10,040**	**10,350**	**10,769**	**11,275**
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				10				90		189	315	500	500
&	New Resources						104	301	467	466	544	799	1,211	1,789
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,972**	**10,948**	**10,782**	**10,964**	**10,981**	**10,894**	**11,044**	**11,387**	**11,846**	**12,403**
	Reserves	1,223	1,179	1,274	997	1,192	980	1,005	998	990	1,004	1,035	1,077	1,127
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.0	10.1	10.0	10.0	10.0	10.0	10.0	10.0

Natural Gas Price Jump 25% in 1998
(2.4% till 2006, 1.0% thereafter)
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.7	11.6	17.5	23.8	30.3	36.8	43.5	50.3	57.1	67.2	84.1	104.1	129.3
	OWC Geothermal													
O	OWC Cogen 1													196.8
W	OWC Cogen 2						92.9	269.7	417.5	396.9	463.0	679.1	1,031.0	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													14.1
	OWC Pump Storage													
	Total	**5.7**	**11.6**	**17.5**	**23.8**	**30.3**	**129.7**	**313.1**	**467.8**	**453.9**	**530.2**	**763.2**	**1,135.1**	**1,452.1**
	DSM Programs	0.5	0.9	1.3	1.8	2.3	2.8	3.3	3.9	4.4	5.2	6.6	8.2	10.2
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.3**	**2.8**	**3.3**	**3.9**	**4.4**	**5.2**	**6.6**	**8.2**	**10.2**
	DSM Programs	7.8	15.4	23.5	32.8	41.9	51.7	61.6	71.5	82.0	98.1	126.1	160.1	204.5
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													186.2
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.8**	**41.9**	**51.7**	**61.6**	**71.5**	**82.0**	**98.1**	**126.1**	**160.1**	**390.7**
	DSM Programs	2.3	4.6	6.9	9.2	11.5	14.3	17.1	19.9	22.8	27.0	34.1	42.6	53.8
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.3**	**4.6**	**6.9**	**9.2**	**11.5**	**14.3**	**17.1**	**19.9**	**22.8**	**27.0**	**34.1**	**42.6**	**53.8**
	DSM Programs	16.3	32.4	49.3	67.6	86.0	105.7	125.5	145.6	166.2	197.5	250.9	315.1	397.8
	Short Term Cap Purch				0.0				0.1		0.2	0.3	0.5	0.5
T	Cogeneration						92.9	269.7	417.5	396.9	463.0	679.1	1,031.0	1,495.0
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													14.1
	Storage													
	Total	**16.3**	**32.4**	**49.3**	**67.6**	**86.0**	**198.6**	**395.1**	**563.2**	**563.1**	**660.7**	**930.3**	**1,346.5**	**1,907.3**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.5	1,065.6	1,210.3	1,217.3	1,260.0	1,254.2	1,304.0	1,313.6	1,349.7	1,299.6	1,275.8	1,235.3	1,285.6
E	**DSM Programs**	(16.3)	(32.4)	(49.3)	(67.6)	(86.0)	(105.7)	(125.5)	(145.6)	(166.2)	(197.5)	(250.9)	(315.1)	(397.8)
M	**Total Requirements**	8,986.4	9,098.3	9,068.9	8,950.7	8,862.1	8,846.4	8,999.7	9,058.5	9,027.0	9,042.5	9,259.7	9,503.7	9,904.5
	Existing Generation	7,773.7	7,850.4	7,825.4	7,715.9	7,822.6	7,935.3	7,938.2	7,882.7	7,846.1	7,785.3	7,804.3	7,679.4	7,629.9
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	714.0	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.3	278.0	278.4	271.0	325.5	322.1	306.3	292.3	318.1	328.2	328.9	349.0	356.4
R	**New Resources**						92.9	269.7	417.6	396.9	463.2	679.4	1,031.5	1,509.6
	Total Resources	8,986.4	9,098.3	9,068.9	8,950.7	8,862.1	8,846.4	8,999.8	9,058.5	9,026.9	9,042.5	9,259.7	9,503.8	9,904.5

Natural Gas Price Jump 25% in 1998
(2.4% till 2006, 1.0% thereafter)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	32	49	67	84	104	123	143	163	195	248	311	392
			After Conservation													
			System Load (MWa)	5,709	5,760	5,854	5,990	6,094	6,218	6,353	6,514	6,608	6,712	7,117	7,509	7,905
	0.65		Energy Sales (MWa)	5,158	5,255	5,354	5,463	5,574	5,688	5,804	5,911	5,983	6,035	6,346	6,674	7,059
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,179	8,401	8,613	8,894	9,219	9,484	9,690	9,941	10,146	11,209	12,407	14,508
			Net Conservation Assets ($M)	17	33	50	65	80	93	106	120	134	151	188	218	251
			Utility Cost													
45,696	3.24	Nominal	**Operating Revenues ($M)**	2,146	2,176	2,268	2,340	2,426	2,427	2,515	2,654	2,768	2,926	3,263	3,772	4,404
	0.23	Real		2,146	2,113	2,137	2,141	2,156	2,093	2,106	2,158	2,185	2,243	2,288	2,421	2,512
	2.58	Nominal	Cost in mills/kWh	47.5	47.3	48.4	48.9	49.7	48.7	49.5	51.3	52.8	55.4	58.7	64.5	71.2
	-0.41	Real		47.5	45.9	45.6	44.7	44.2	42.0	41.4	41.7	41.7	42.4	41.2	41.4	40.6
		Nominal	Average Customer Bill ($)	1,602	1,604	1,644	1,665	1,699	1,672	1,704	1,768	1,816	1,890	2,012	2,232	2,453
		Real		1,602	1,557	1,549	1,524	1,510	1,442	1,427	1,438	1,433	1,449	1,411	1,433	1,399
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.4	-2.8	-3.7	-5.4	-7.7	-10.6	-14.2	-18.5	-23.9	-44.9	-77.4	-132.3
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-4.9	-6.8	-9.2	-19.7	-38.6	-80.5
			Energy Svc Charge ($M)	1.6	3.3	5.1	7.0	9.0	11.1	13.3	15.9	17.2	18.9	23.2	27.3	32.1
45,163	3.141	Nominal	**Total Resource Cost ($M)**	2,147	2,179	2,272	2,346	2,434	2,435	2,525	2,665	2,779	2,936	3,266	3,761	4,356
	0.14	Real		2,147	2,116	2,142	2,146	2,162	2,101	2,114	2,167	2,194	2,250	2,291	2,414	2,484
	2.37	Nominal	Cost in mills/kWh	47.4	47.1	48.0	48.5	49.2	48.1	48.7	50.3	51.7	53.9	56.7	61.7	67.0
	-0.61	Real		47.4	45.7	45.3	44.4	43.7	41.5	40.8	40.9	40.8	41.3	39.8	39.6	38.2

Notes:

1) $M = millions of dollars   2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.71**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.83**

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Natural Gas Price Jump 25% in 1998
(2.4% till 2006, 1.0% thereafter)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,016	50,467	51,273	52,026	52,932	54,012	55,197	56,597	57,408	58,316	61,860	65,293	68,748
	MWa	5,710	5,761	5,853	5,939	6,042	6,166	6,301	6,461	6,553	6,657	7,062	7,454	7,848
	Total Annual Emissions (1000 Tons)													
0.63%	CO_2	56,580	57,699	57,888	58,053	57,904	57,717	58,200	58,466	58,623	59,412	60,780	62,725	63,739
0.04%	NO_x	132.6	134.4	133.7	132.5	133.7	134.8	134.8	133.9	133.2	133.7	133.8	134.2	133.6
0.10%	TSP	11.8	11.9	11.9	11.9	11.9	11.9	12.0	11.9	11.9	12.0	12.0	12.0	12.0
	Annual System Emission Rates (Pounds/MWh)													
-1.04%	CO_2	2,262	2,287	2,258	2,232	2,188	2,137	2,109	2,066	2,042	2,038	1,965	1,921	1,854
-1.62%	NO_x	5.30	5.33	5.22	5.09	5.05	4.99	4.89	4.73	4.64	4.58	4.33	4.11	3.89
-1.56%	TSP	0.47	0.47	0.46	0.46	0.45	0.44	0.43	0.42	0.42	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO_2	100	101.07	99.80	98.64	96.70	94.46	93.21	91.32	90.27	90.06	86.86	84.92	81.96
	NO_x	100	100.50	98.41	96.06	95.32	94.14	92.17	89.24	87.54	86.47	81.63	77.56	73.30
	TSP	100	100.32	98.12	96.80	95.43	93.65	91.78	89.38	88.14	87.23	82.24	78.17	74.16

20 Year Emissions (1000 Tons)	Average	Total
CO_2	60,059	1,201,180
NO_x	134	2,676
TSP	12	239

Natural Gas Price Jump 50% in 1998
(2.4% till 2006, 1.0% thereafter)
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				3.8				180.7	90.9	223.7	375.0	500.0	500.0
	DSM Programs	7.6	8.0	8.2	8.4	8.6	8.7	8.8	8.8	8.7	13.5	22.3	26.4	33.0
	OWC Geothermal													
O	OWC Cogen 1						95.8	106.3						
W	OWC Cogen 2							82.0	82.2		132.3	226.4	471.6	296.8
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													78.1
	OWC Pump Storage													
	Total	**7.6**	**8.0**	**8.2**	**8.4**	**8.6**	**104.5**	**197.1**	**91.0**	**8.7**	**145.8**	**248.7**	**498.0**	**407.9**
	DSM Programs	0.6	0.6	0.6	0.6	0.7	0.6	0.7	0.6	0.7	1.5	2.4	2.8	3.6
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.6**	**0.7**	**0.6**	**0.7**	**1.5**	**2.4**	**2.8**	**3.6**
	DSM Programs	12.2	11.8	13.0	13.8	13.5	14.2	14.1	14.4	15.0	23.1	39.9	47.9	61.7
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													200.1
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**12.2**	**11.8**	**13.0**	**13.8**	**13.5**	**14.2**	**14.1**	**14.4**	**15.0**	**23.1**	**39.9**	**47.9**	**261.8**
	DSM Programs	2.8	2.8	3.2	3.3	3.4	3.4	3.4	3.4	3.5	5.2	8.4	9.5	12.1
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**3.2**	**3.3**	**3.4**	**3.4**	**3.4**	**3.4**	**3.5**	**5.2**	**8.4**	**9.5**	**12.1**
T	DSM Programs	23.2	23.2	25.0	26.1	26.2	26.9	27.0	27.2	27.9	43.3	73.0	86.6	110.4
O	Short Term Cap Purch				3.8				180.7	90.9	223.7	375.0	500.0	500.0
T	Cogeneration						95.8	188.3	82.2		132.3	226.4	471.6	496.9
A	Combined Cycle CT													
L	All Others													78.1
	Total	**23.2**	**23.2**	**25.0**	**29.9**	**26.2**	**122.7**	**215.3**	**290.1**	**118.8**	**399.3**	**674.4**	**1,058.2**	**1,185.4**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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	(23)	(46)	(71)	(98)	(124)	(151)	(178)	(205)	(233)	(276)	(349)	(436)	(546)
T	**Total Requirements**	**9,872**	**10,005**	**9,853**	**9,968**	**9,749**	**9,794**	**9,951**	**9,973**	**9,895**	**10,030**	**10,339**	**10,755**	**11,259**
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				4				181	91	224	375	500	500
&	New Resources						96	284	366	366	498	725	1,197	1,772
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,966**	**10,948**	**10,774**	**10,947**	**10,971**	**10,885**	**11,033**	**11,373**	**11,832**	**12,386**
	Reserves	1,224	1,181	1,279	997	1,199	980	995	997	990	1,003	1,034	1,075	1,126
	Reserve Margin (RM) (%	12.4	11.8	13.0	10.0	12.3	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Natural Gas Price Jump 50% in 1998
(2.4% till 2006, 1.0% thereafter)
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	6.0	12.1	18.4	25.0	31.7	38.5	45.4	52.3	59.2	69.9	87.6	108.6	135.0
	OWC Geothermal													
O	OWC Cogen 1						94.9	200.1	200.1	182.2	182.2	173.2	173.2	173.2
W	OWC Cogen 2							69.8	139.7	139.7	252.3	445.0	846.4	1,099.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													15.7
	OWC Pump Storage													
	Total	**6.0**	**12.1**	**18.4**	**25.0**	**31.7**	**133.3**	**315.2**	**392.2**	**381.2**	**504.4**	**705.8**	**1,128.2**	**1,422.9**
	DSM Programs	0.5	1.0	1.5	2.0	2.5	3.1	3.6	4.1	4.7	5.7	7.3	9.3	11.7
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**1.0**	**1.5**	**2.0**	**2.5**	**3.1**	**3.6**	**4.1**	**4.7**	**5.7**	**7.3**	**9.3**	**11.7**
	DSM Programs	8.4	16.7	25.7	35.3	44.7	54.7	64.7	74.8	85.4	101.7	129.9	164.0	208.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													170.3
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**8.4**	**16.7**	**25.7**	**35.3**	**44.7**	**54.7**	**64.7**	**74.8**	**85.4**	**101.7**	**129.9**	**164.0**	**378.5**
	DSM Programs	2.3	4.6	7.2	10.0	12.7	15.5	18.3	21.2	24.0	28.5	35.9	44.8	56.3
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.3**	**4.6**	**7.2**	**10.0**	**12.7**	**15.5**	**18.3**	**21.2**	**24.0**	**28.5**	**35.9**	**44.8**	**56.3**
	DSM Programs	17.1	34.3	52.9	72.3	91.7	111.7	131.9	152.4	173.3	205.7	260.7	326.7	411.2
	Short Term Cap Purch								0.2	0.1	0.2	0.4	0.4	0.4
T	Cogeneration						94.9	269.9	339.9	322.0	434.5	618.2	1,019.6	1,442.5
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													15.7
	Storage													
	Total	**17.1**	**34.3**	**52.9**	**72.3**	**91.7**	**206.6**	**401.8**	**492.4**	**495.3**	**640.4**	**879.3**	**1,346.6**	**1,869.8**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.8	1,079.3	1,238.9	1,289.4	1,314.9	1,283.4	1,332.6	1,308.0	1,368.5	1,325.9	1,310.4	1,280.3	1,319.5
E	**DSM Programs**	(17.1)	(34.3)	(52.9)	(72.3)	(91.7)	(111.7)	(131.9)	(152.4)	(173.3)	(205.7)	(260.7)	(326.7)	(411.2)
M	**Total Requirements**	8,985.9	9,110.0	9,093.8	9,018.1	8,911.3	8,869.5	9,021.9	9,046.2	9,038.7	9,060.7	9,284.4	9,537.1	9,925.0
	Existing Generation	7,773.3	7,866.9	7,870.2	7,815.7	7,923.3	7,998.8	8,011.8	7,941.7	7,960.7	7,877.4	7,927.7	7,759.9	7,716.2
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	714.0	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.2	273.2	258.6	238.7	274.0	279.8	254.6	298.6	290.1	282.7	291.1	313.4	341.7
R	**New Resources**						94.9	269.9	340.1	322.1	434.8	618.6	1,019.9	1,458.6
	Total Resources	8,985.9	9,110.0	9,093.8	9,018.1	8,911.3	8,869.5	9,021.9	9,046.2	9,038.7	9,060.7	9,284.4	9,537.1	9,925.0

Natural Gas Price Jump 50% in 1998
(2.4% till 2006, 1.0% thereafter)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	17	34	53	72	92	112	132	152	173	206	261	327	411
			After Conservation													
			System Load (MWa)	5,708	5,758	5,851	5,984	6,087	6,210	6,345	6,504	6,598	6,701	7,104	7,494	7,886
	0.64		Energy Sales (MWa)	5,157	5,254	5,350	5,458	5,568	5,681	5,796	5,903	5,973	6,025	6,334	6,660	7,041
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,013	8,181	8,406	8,644	8,975	9,301	9,533	9,754	10,027	10,234	11,268	12,524	14,409
			Net Conservation Assets ($M)	17	35	52	69	84	99	113	127	142	160	199	230	265
			Utility Cost													
45,571	3.24	Nominal	**Operating Revenues ($M)**	2,145	2,161	2,249	2,320	2,402	2,398	2,492	2,657	2,752	2,902	3,259	3,760	4,421
	0.24	Real		2,145	2,098	2,120	2,123	2,135	2,069	2,087	2,160	2,173	2,224	2,286	2,413	2,521
	2.59	Nominal	Cost in mills/kWh	47.5	47.0	48.0	48.5	49.3	48.2	49.1	51.4	52.6	55.0	58.7	64.5	71.7
	-0.40	Real		47.5	45.6	45.2	44.4	43.8	41.6	41.1	41.8	41.5	42.2	41.2	41.4	40.9
		Nominal	Average Customer Bill ($)	1,602	1,592	1,630	1,651	1,682	1,652	1,688	1,770	1,805	1,875	2,009	2,225	2,463
		Real		1,602	1,546	1,537	1,511	1,495	1,425	1,414	1,439	1,425	1,437	1,409	1,428	1,404
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.9	-3.7	-5.4	-7.8	-10.7	-14.4	-18.7	-24.4	-46.6	-81.8	-142.8
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-5.0	-6.9	-9.3	-20.1	-39.8	-84.4
			Energy Svc Charge ($M)	1.7	3.5	5.4	7.4	9.6	11.8	14.2	16.8	18.3	20.2	24.7	29.1	33.9
45,036	3.145	Nominal	**Total Resource Cost ($M)**	2,147	2,164	2,254	2,326	2,410	2,408	2,503	2,669	2,764	2,913	3,263	3,749	4,371
	0.14	Real		2,147	2,101	2,124	2,129	2,142	2,077	2,096	2,170	2,182	2,233	2,289	2,407	2,493
	2.38	Nominal	Cost in mills/kWh	47.4	46.7	47.7	48.1	48.7	47.5	48.3	50.4	51.4	53.5	56.7	61.5	67.3
	-0.61	Real		47.4	45.4	44.9	44.0	43.3	41.0	40.4	41.0	40.6	41.0	39.8	39.5	38.4

Notes:

1) $M = millions of dollars 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.67**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.71**

Natural Gas Price Jump 50% in 1998
(2.4% till 2006, 1.0% thereafter)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,009	50,449	51,241	51,985	52,882	53,959	55,140	56,539	57,347	58,244	61,774	65,191	68,630
	MWa	5,709	5,759	5,849	5,934	6,037	6,160	6,295	6,454	6,546	6,649	7,052	7,442	7,835
	Total Annual Emissions (1000 Tons)													
0.67%	CO2	56,575	57,787	58,135	58,628	58,486	58,017	58,483	58,641	59,116	59,765	61,324	62,999	64,204
0.10%	NOx	132.6	134.8	134.6	134.5	135.8	136.1	136.3	134.9	135.3	135.3	136.1	135.7	135.2
0.13%	TSP	11.8	12.0	11.9	12.0	12.1	12.0	12.1	12.0	12.0	12.1	12.1	12.1	12.1
	Annual System Emission Rates (Pounds/MWh)													
-1.00%	CO2	2,263	2,291	2,269	2,256	2,212	2,150	2,121	2,074	2,062	2,052	1,985	1,933	1,871
-1.55%	NOx	5.30	5.34	5.26	5.17	5.14	5.04	4.94	4.77	4.72	4.65	4.41	4.16	3.94
-1.52%	TSP	0.47	0.47	0.47	0.46	0.46	0.45	0.44	0.42	0.42	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	101.25	100.29	99.69	97.76	95.04	93.75	91.68	91.12	90.70	87.75	85.42	82.69
	NOx	100	100.78	99.13	97.59	96.86	95.12	93.26	90.02	89.02	87.67	83.14	78.53	74.32
	TSP	100	100.65	98.81	97.89	96.92	94.51	92.71	89.98	88.95	87.80	83.17	78.85	74.75

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,419	1,208,375
NOx	135	2,707
TSP	12	241

Natural Gas Price Jump 110% in 1998
(To Bring in Coal)
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch							23.1	216.0	124.9	321.2	469.0	500.0	500.0
	DSM Programs	8.5	8.6	8.8	8.9	9.0	9.0	9.1	9.2	9.1	13.6	22.4	26.5	33.0
	OWC Geothermal													
O	OWC Cogen 1						116.2	85.9						
W	OWC Cogen 2												128.4	315.9
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													160.5
	Total	**8.5**	**8.6**	**8.8**	**8.9**	**9.0**	**125.2**	**95.0**	**9.2**	**9.1**	**13.6**	**22.4**	**154.9**	**509.4**
	DSM Programs	0.7	0.6	0.6	0.6	0.7	0.9	0.9	1.0	0.9	1.5	2.4	2.9	3.5
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans						34.4	48.4	23.8		163.6	44.3	21.4	
O	Idaho Htr/Id Trans L													
	Total	**0.7**	**0.6**	**0.6**	**0.6**	**0.7**	**35.3**	**49.3**	**24.8**	**0.9**	**165.1**	**46.7**	**24.3**	**3.5**
	DSM Programs	12.6	12.2	13.2	13.9	13.5	14.7	14.7	14.8	15.6	23.8	41.3	49.7	64.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4							51.6	69.1	0.0	69.3			72.0
	Utah IGCC CT													
	Utah PC Hunter 4											221.6	178.4	
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													24.1
	Utah Wyo/Ut Tran L													
	Total	**12.6**	**12.2**	**13.2**	**13.9**	**13.5**	**14.7**	**66.3**	**83.9**	**15.6**	**93.1**	**262.9**	**228.1**	**160.3**
	DSM Programs	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	5.2	8.4	9.6	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2											7.0	257.0	
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**3.2**	**3.2**	**3.3**	**3.3**	**3.3**	**3.4**	**3.4**	**3.5**	**3.5**	**5.2**	**15.4**	**266.6**	**11.9**
T	DSM Programs	25.0	24.6	25.9	26.7	26.5	28.0	28.1	28.5	29.1	44.1	74.5	88.7	112.6
O	Short Term Cap Purch							23.1	216.0	124.9	321.2	469.0	500.0	500.0
T	Cogeneration						116.2	85.9					128.4	315.9
A	Combined Cycle CT													
L	All Others						34.4	100.0	92.9	0.0	232.9	272.9	456.8	256.6
	Total	**25.0**	**24.6**	**25.9**	**26.7**	**26.5**	**178.6**	**237.1**	**337.4**	**154.0**	**598.2**	**816.4**	**1,173.9**	**1,185.1**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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	(25)	(50)	(75)	(102)	(129)	(157)	(185)	(213)	(242)	(286)	(361)	(450)	(562)
T	**Total Requirements**	**9,870**	**10,001**	**9,849**	**9,964**	**9,744**	**9,788**	**9,944**	**9,965**	**9,886**	**10,020**	**10,327**	**10,741**	**11,243**
E														
M	Existing Generation	9,949	9,994	10,010	9,842	9,848	9,620	9,771	9,658	9,662	9,380	9,348	9,188	9,188
	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							23	216	125	321	469	500	500
&	New Resources						151	337	429	429	663	935	1,520	2,093
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,962**	**10,948**	**10,794**	**10,939**	**10,961**	**10,874**	**11,022**	**11,360**	**11,816**	**12,368**
	Reserves	1,226	1,184	1,283	998	1,204	1,006	994	997	989	1,002	1,032	1,074	1,124
	Reserve Margin (RM) (%	12.4	11.8	13.0	10.0	12.4	10.3	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Natural Gas Price Jump 110% in 1998
(To Bring in Coal)
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	6.6	13.3	20.1	27.1	34.2	41.3	48.5	55.8	63.0	73.8	91.6	112.7	139.1
	OWC Geothermal													
O	OWC Cogen 1						104.8	182.2	182.2	173.2	173.2	173.2	172.0	172.0
W	OWC Cogen 2												109.3	378.1
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													39.8
	Total	**6.6**	**13.3**	**20.1**	**27.1**	**34.2**	**146.1**	**230.7**	**238.0**	**236.2**	**246.9**	**264.8**	**394.0**	**729.0**
	DSM Programs	0.5	1.0	1.6	2.1	2.6	3.2	3.9	4.5	5.2	6.2	7.8	9.8	12.2
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans						31.3	75.2	96.8	96.8	245.3	285.6	305.0	305.0
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**1.0**	**1.6**	**2.1**	**2.6**	**34.5**	**79.1**	**101.3**	**101.9**	**251.5**	**293.4**	**314.8**	**317.2**
	DSM Programs	8.7	17.2	26.3	36.0	45.4	55.9	66.3	76.9	88.0	105.1	134.7	170.6	217.3
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4							46.8	109.4	109.4	172.3	172.3	172.3	235.8
	Utah IGCC CT													
	Utah PC Hunter 4											203.1	366.6	366.6
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													6.0
	Utah Wyo/Ut Tran L													
	Total	**8.7**	**17.2**	**26.3**	**36.0**	**45.4**	**55.9**	**113.1**	**186.4**	**197.4**	**277.4**	**510.1**	**709.5**	**825.6**
	DSM Programs	2.7	5.4	8.1	10.8	13.7	16.6	19.6	22.6	25.7	30.3	38.0	47.1	58.5
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2											6.4	241.9	241.9
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.7**	**5.4**	**8.1**	**10.8**	**13.7**	**16.6**	**19.6**	**22.6**	**25.7**	**30.3**	**44.4**	**289.0**	**300.4**
	DSM Programs	18.4	36.9	56.1	75.9	95.9	117.0	138.3	159.8	181.9	215.3	272.1	340.1	427.0
	Short Term Cap Purch							0.0	0.2	0.1	0.2	0.4	0.4	0.3
T	Cogeneration						104.8	182.2	182.2	173.2	173.2	173.2	281.3	550.1
O	Combined Cycle CT													
T	Coal							46.8	109.4	109.4	172.3	381.9	780.8	844.3
A	Transmission						31.3	75.2	96.8	96.8	245.3	285.6	305.0	305.0
L	Simple Cycle													
	Storage													45.8
	Total	**18.4**	**36.9**	**56.1**	**75.9**	**95.9**	**253.0**	**442.5**	**548.4**	**561.3**	**806.4**	**1,113.1**	**1,707.6**	**2,172.5**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	315.3
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	883.3	1,197.3	1,381.6	1,392.7	1,359.2	1,364.5	1,379.4	1,368.4	1,402.3	1,351.3	1,329.4	1,347.7	1,362.0
E	**DSM Programs**	(18.4)	(36.9)	(56.1)	(75.9)	(95.9)	(117.0)	(138.3)	(159.8)	(181.9)	(215.3)	(272.1)	(340.1)	(427.0)
M	**Total Requirements**	8,985.1	9,225.5	9,233.4	9,117.7	8,951.4	8,945.3	9,062.4	9,099.1	9,063.9	9,076.4	9,292.1	9,591.1	10,010.4
	Existing Generation	7,772.7	8,009.7	8,043.2	7,956.3	8,013.4	8,051.2	8,025.6	7,991.5	7,976.1	7,762.7	7,730.2	7,529.3	7,546.9
L	**Long Term Purchases**	869.3	970.2	965.3	964.0	714.0	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.0	245.7	224.8	197.3	224.0	262.0	247.0	253.2	242.4	256.8	273.8	250.4	309.4
R	**New Resources**						136.0	304.3	388.6	379.5	591.0	841.0	1,367.5	1,745.4
	Total Resources	8,985.0	9,225.5	9,233.3	9,117.7	8,951.4	8,945.4	9,062.4	9,099.1	9,063.9	9,076.4	9,292.1	9,591.1	10,010.4

Natural Gas Price Jump 110% in 1998
(To Bring in Coal)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	18	37	56	76	96	117	138	160	182	215	272	340	427
			After Conservation													
			System Load (MWa)	5,707	5,756	5,847	5,981	6,083	6,205	6,338	6,497	6,590	6,691	7,092	7,480	7,871
	0.64		Energy Sales (MWa)	5,156	5,251	5,347	5,454	5,564	5,676	5,790	5,896	5,966	6,016	6,323	6,647	7,027
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,015	8,185	8,415	8,671	9,025	9,369	9,640	9,886	10,214	10,510	11,910	13,462	15,422
			Net Conservation Assets ($M)	18	37	55	72	88	103	118	133	149	168	209	241	277
			Utility Cost													
44,044	3.13	Nominal	**Operating Revenues ($M)**	2,145	2,120	2,202	2,267	2,342	2,323	2,417	2,579	2,672	2,816	3,125	3,559	4,286
	0.12	Real		2,145	2,058	2,075	2,075	2,081	2,004	2,024	2,097	2,110	2,158	2,191	2,285	2,444
	2.47	Nominal	Cost in mills/kWh	47.5	46.1	47.0	47.5	48.1	46.7	47.7	49.9	51.1	53.4	56.4	61.1	69.6
	-0.51	Real		47.5	44.8	44.3	43.4	42.7	40.3	39.9	40.6	40.4	41.0	39.6	39.2	39.7
		Nominal	Average Customer Bill ($)	1,602	1,562	1,596	1,614	1,640	1,600	1,637	1,719	1,753	1,819	1,927	2,106	2,387
		Real		1,602	1,516	1,504	1,477	1,457	1,380	1,371	1,397	1,384	1,394	1,351	1,352	1,362
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.9	-3.7	-5.5	-7.9	-11.0	-14.9	-19.4	-25.4	-48.4	-84.7	-146.9
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.7	-2.5	-3.6	-5.1	-7.0	-9.6	-20.8	-41.3	-87.4
			Energy Svc Charge ($M)	1.8	3.7	5.7	7.9	10.1	12.4	14.9	17.7	19.2	21.1	25.9	30.4	35.5
43,509	3.021	Nominal	**Total Resource Cost ($M)**	2,147	2,123	2,207	2,274	2,350	2,333	2,429	2,592	2,684	2,827	3,130	3,549	4,234
	0.02	Real		2,147	2,061	2,080	2,081	2,088	2,013	2,034	2,107	2,119	2,167	2,195	2,278	2,415
	2.25	Nominal	Cost in mills/kWh	47.4	45.9	46.7	47.0	47.5	46.1	46.9	49.0	50.0	51.9	54.4	58.2	65.2
	-0.73	Real		47.4	44.5	44.0	43.0	42.2	39.7	39.2	39.8	39.4	39.8	38.1	37.4	37.2

Notes:

1) $M = millions of dollars 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **40.33**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **38.37**

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Natural Gas Price Jump 110% in 1998
(To Bring in Coal)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	49,997	50,427	51,213	51,952	52,846	53,913	55,086	56,473	57,271	58,159	61,675	65,074	69,006
	MWa	5,707	5,757	5,846	5,931	6,033	6,154	6,288	6,447	6,538	6,639	7,040	7,429	7,877
	Total Annual Emissions (1000 Tons)													
1.10%	CO_2	56,566	58,546	59,088	59,371	58,938	58,410	59,081	59,833	60,129	61,105	63,627	67,873	69,625
0.32%	NO_x	132.5	137.4	138.0	137.1	137.4	137.5	137.9	137.9	137.7	138.1	139.1	140.4	140.9
0.39%	TSP	11.8	12.2	12.2	12.3	12.2	12.2	12.2	12.2	12.2	12.3	12.4	12.6	12.7
	Annual System Emission Rates (Pounds/MWh)													
-0.60%	CO_2	2,263	2,322	2,308	2,286	2,231	2,167	2,145	2,119	2,100	2,101	2,063	2,086	2,018
-1.36%	NO_x	5.30	5.45	5.39	5.28	5.20	5.10	5.01	4.88	4.81	4.75	4.51	4.31	4.08
-1.29%	TSP	0.47	0.49	0.48	0.47	0.46	0.45	0.44	0.43	0.43	0.42	0.40	0.39	0.37
	Emission Rates as Percent of 1997 Base													
	CO_2	100	102.62	101.98	101.01	98.58	95.76	94.80	93.65	92.80	92.86	91.19	92.19	89.18
	NO_x	100	102.78	101.61	99.54	98.07	96.22	94.43	92.09	90.69	89.60	85.07	81.36	77.03
	TSP	100	102.83	101.14	99.99	98.10	95.59	93.84	91.60	90.27	89.29	85.19	82.36	78.07

20 Year Emissions (1000 Tons)	Average	Total
CO_2	62,734	1,254,672
NO_x	139	2,770
TSP	12	247

Lower Gas Resource Availability

Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				12.6				88.3		83.7	152.0	416.4	500.0
	DSM Programs	6.9	7.1	7.2	7.6	7.7	7.7	8.0	8.5	8.4	12.5	21.2	25.3	31.7
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2						109.7	190.4	176.3		183.3	312.0	334.9	
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.9**	**7.1**	**7.2**	**7.6**	**7.7**	**117.4**	**198.4**	**184.8**	**8.4**	**195.8**	**333.2**	**360.2**	**31.7**
	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
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	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	13.6	13.5	13.8	14.4	22.7	39.4	47.5	61.5
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													494.5
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.6**	**13.5**	**13.8**	**14.4**	**22.7**	**39.4**	**47.5**	**556.0**
	DSM Programs	2.8	2.8	2.8	2.9	2.9	3.0	3.0	3.0	3.0	5.2	8.4	9.4	12.0
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**	**3.0**	**3.0**	**5.2**	**8.4**	**9.4**	**12.0**
T	DSM Programs	21.8	21.6	22.5	23.6	23.5	24.9	25.1	25.9	26.4	41.4	70.7	84.1	107.6
O	Short Term Cap Purch				12.6				88.3		83.7	152.0	416.4	500.0
T	Cogeneration						109.7	190.4	176.3		183.3	312.0	334.9	494.5
A	Combined Cycle CT													
L	All Others													
	Total	**21.8**	**21.6**	**22.5**	**36.2**	**23.5**	**134.6**	**215.5**	**290.5**	**26.4**	**308.4**	**534.7**	**835.4**	**1,102.1**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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)	(90)	(113)	(138)	(163)	(189)	(215)	(257)	(327)	(412)	(519)
T	**Total Requirements**	**9,873**	**10,008**	**9,858**	**9,976**	**9,760**	**9,807**	**9,966**	**9,989**	**9,913**	**10,049**	**10,361**	**10,779**	**11,286**
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				88		84	152	416	500
&	New Resources						110	300	477	476	659	972	1,307	1,801
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**10,788**	**10,963**	**10,989**	**10,904**	**11,054**	**11,397**	**11,858**	**12,415**
	Reserves	1,223	1,178	1,273	998	1,188	981	997	999	991	1,005	1,036	1,078	1,129
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Lower Gas Resource Availability

Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.4	10.8	16.4	22.5	28.6	34.8	41.1	47.8	54.4	64.3	81.1	101.1	126.2
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2						81.7	191.7	287.2	280.9	354.9	551.1	784.2	815.5
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.4**	**10.8**	**16.4**	**22.5**	**28.6**	**116.4**	**232.8**	**335.0**	**335.3**	**419.1**	**632.1**	**885.2**	**941.7**
	DSM Programs	0.5	0.9	1.3	1.8	2.2	2.7	3.1	3.6	4.1	5.0	6.3	7.9	10.0
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.2**	**2.7**	**3.1**	**3.6**	**4.1**	**5.0**	**6.3**	**7.9**	**10.0**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	50.1	59.6	69.3	79.4	95.4	123.2	157.0	201.0
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													348.7
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**50.1**	**59.6**	**69.3**	**79.4**	**95.4**	**123.2**	**157.0**	**549.8**
	DSM Programs	2.2	4.5	6.8	9.1	11.5	13.9	16.3	18.7	21.1	25.3	32.6	41.2	52.5
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.5**	**13.9**	**16.3**	**18.7**	**21.1**	**25.3**	**32.6**	**41.2**	**52.5**
	DSM Programs	15.9	31.6	48.1	65.5	82.9	101.4	120.1	139.3	159.0	189.9	243.1	307.2	389.7
	Short Term Cap Purch				0.0				0.1		0.1	0.2	0.4	0.5
T	Cogeneration						81.7	191.7	287.2	280.9	354.9	551.1	784.2	1,164.2
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.9**	**31.6**	**48.1**	**65.5**	**82.9**	**183.1**	**311.8**	**426.6**	**439.9**	**544.9**	**794.3**	**1,091.8**	**1,554.4**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.4	984.2	1,103.2	1,156.1	1,198.3	1,195.7	1,228.2	1,219.6	1,285.1	1,236.0	1,249.7	1,159.5	1,155.0
E	**DSM Programs**	(15.9)	(31.6)	(48.1)	(65.5)	(82.9)	(101.4)	(120.1)	(139.3)	(159.0)	(189.9)	(243.1)	(307.2)	(389.7)
M	**Total Requirements**	8,986.7	9,017.6	8,962.9	8,891.6	8,803.5	8,792.2	8,929.3	8,970.9	8,969.6	8,986.6	9,241.3	9,435.9	9,782.0
	Existing Generation	7,773.9	7,713.8	7,661.5	7,604.5	7,741.8	7,856.5	7,893.4	7,869.8	7,868.6	7,801.4	7,866.2	7,803.7	7,806.2
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.4	333.9	336.4	323.4	349.0	358.0	358.7	347.9	354.3	364.4	376.8	403.7	402.5
R	**New Resources**						81.7	191.6	287.3	280.8	354.9	551.2	784.6	1,164.7
	Total Resources	8,986.7	9,017.6	8,962.9	8,891.6	8,803.5	8,792.2	8,929.4	8,970.8	8,969.6	8,986.6	9,241.3	9,435.9	9,782.0

Lower Gas Resource Availability

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	32	48	66	83	101	120	139	159	190	243	307	390
			After Conservation													
			System Load (MWa)	5,710	5,761	5,855	5,991	6,096	6,220	6,356	6,517	6,613	6,717	7,121	7,513	7,908
	0.64		Energy Sales (MWa)	5,158	5,256	5,355	5,464	5,576	5,691	5,806	5,915	5,987	6,039	6,350	6,678	7,061
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,179	8,401	8,614	8,895	9,221	9,496	9,743	10,039	10,252	11,357	12,457	14,359
			Net Conservation Assets ($M)	16	33	49	64	78	92	104	118	131	148	184	214	248
			Utility Cost													
45,866	3.24	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,283	2,358	2,450	2,454	2,545	2,680	2,799	2,933	3,273	3,803	4,424
	0.23	Real		2,146	2,127	2,151	2,158	2,177	2,117	2,132	2,179	2,210	2,248	2,296	2,441	2,523
	2.58	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.3	50.2	49.2	50.0	51.7	53.4	55.5	58.9	65.0	71.5
	-0.41	Real		47.5	46.2	45.9	45.1	44.6	42.5	41.9	42.1	42.1	42.5	41.3	41.7	40.8
		Nominal	Average Customer Bill ($)	1,602	1,614	1,654	1,678	1,716	1,690	1,724	1,786	1,836	1,895	2,019	2,250	2,464
		Real		1,602	1,567	1,559	1,536	1,524	1,458	1,444	1,452	1,449	1,452	1,416	1,444	1,405
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.9	-3.7	-5.4	-7.8	-10.7	-14.3	-18.6	-24.1	-45.8	-80.2	-140.4
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-5.0	-6.8	-9.3	-19.9	-39.3	-83.1
			Energy Svc Charge ($M)	1.6	3.3	5.1	6.9	8.9	11.0	13.1	15.6	16.8	18.5	22.5	26.6	31.3
45,319	3.141	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,287	2,364	2,458	2,462	2,555	2,691	2,809	2,943	3,276	3,790	4,372
	0.14	Real		2,147	2,129	2,156	2,163	2,184	2,124	2,140	2,188	2,218	2,255	2,298	2,433	2,493
	2.37	Nominal	Cost in mills/kWh	47.4	47.4	48.4	48.9	49.6	48.6	49.3	50.8	52.3	54.1	56.9	62.2	67.3
	-0.61	Real		47.4	46.0	45.6	44.7	44.1	41.9	41.3	41.3	41.3	41.4	39.9	39.9	38.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.85**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.96**

Lower Gas Resource Availability

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,020	50,473	51,283	52,044	52,960	54,050	55,245	56,653	57,472	58,383	61,928	65,363	68,819
	MWa	5,710	5,762	5,854	5,941	6,046	6,170	6,306	6,467	6,561	6,665	7,069	7,461	7,856
	Total Annual Emissions (1000 Tons)													
0.73%	CO2	56,583	56,896	56,926	57,403	57,463	57,380	58,026	58,485	58,848	59,600	61,290	63,572	65,021
0.17%	NOx	132.6	131.7	130.4	130.2	132.2	133.5	134.1	133.7	133.7	134.1	135.3	136.7	137.0
0.18%	TSP	11.8	11.7	11.7	11.7	11.8	11.8	11.9	11.9	11.9	11.9	12.0	12.2	12.2
	Annual System Emission Rates (Pounds/MWh)													
-0.94%	CO2	2,262	2,255	2,220	2,206	2,170	2,123	2,101	2,065	2,048	2,042	1,979	1,945	1,890
-1.49%	NOx	5.30	5.22	5.09	5.00	4.99	4.94	4.85	4.72	4.65	4.59	4.37	4.18	3.98
-1.49%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.13	97.50	95.92	93.85	92.85	91.26	90.52	90.24	87.49	85.98	83.52
	NOx	100	98.43	95.95	94.39	94.16	93.17	91.56	89.03	87.79	86.63	82.42	78.92	75.13
	TSP	100	98.60	96.58	95.40	94.40	92.87	91.10	88.75	87.68	86.58	82.29	78.84	75.17

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,307	1,206,133
NOx	134	2,687
TSP	12	239

125 MW OWC Industrial Customer
Load Loss in 1999
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch								44.4		91.6	198.1	446.3	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
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2						78.4	199.5	107.5		132.3	274.6	352.3	162.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**86.1**	**207.3**	**115.6**	**8.0**	**144.8**	**295.2**	**376.7**	**192.6**
	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.5	0.6	1.0	1.6	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.5**	**0.6**	**1.0**	**1.6**	**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													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													363.6
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	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**	**425.0**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	2.9	3.0	3.0	3.1	5.2	8.3	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**2.9**	**3.0**	**3.0**	**3.1**	**5.2**	**8.3**	**9.5**	**11.9**
T	DSM Programs	21.7	21.6	22.3	23.2	23.6	24.2	24.4	25.3	26.1	41.4	69.8	83.1	106.3
O	Short Term Cap Purch								44.4		91.6	198.1	446.3	500.0
T	Cogeneration						78.4	199.5	107.5		132.3	274.6	352.3	525.6
A	Combined Cycle CT													
L	All Others													
	Total	**21.7**	**21.6**	**22.3**	**23.2**	**23.6**	**102.6**	**223.9**	**177.2**	**26.1**	**265.3**	**542.5**	**881.7**	**1,131.9**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,313	7,403	7,430	7,646	7,815	8,012	8,226	8,475	8,633	8,819	9,451	10,079	10,738
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	9,733	9,852	9,636	9,683	9,843	9,867	9,790	9,927	10,239	10,659	11,167
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								44		92	198	446	500
&	New Resources						78	278	386	385	517	792	1,145	1,670
R	**Total Resources**	11,096	11,185	11,131	10,962	10,948	10,756	10,941	10,854	10,813	10,920	11,263	11,726	12,284
	Reserves	1,223	1,178	1,398	1,109	1,313	1,073	1,097	987	1,023	993	1,024	1,066	1,117
	Reserve Margin (RM) (%	12.4	11.8	14.4	11.3	13.6	11.1	11.1	10.0	10.4	10.0	10.0	10.0	10.0

125 MW OWC Industrial Customer
Load Loss in 1999
Cumulative Annual Energy (MWa)

		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													
W	OWC Cogen 2						76.3	248.9	345.1	345.1	440.6	674.3	974.1	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**110.0**	**288.7**	**391.3**	**397.6**	**502.9**	**752.9**	**1,072.1**	**1,234.4**
	DSM Programs	0.4	0.9	1.3	1.7	2.2	2.7	3.1	3.6	4.0	4.8	6.1	7.6	9.6
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.2**	**2.7**	**3.1**	**3.6**	**4.0**	**4.8**	**6.1**	**7.6**	**9.6**
	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	199.0
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													309.5
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	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**	**508.5**
	DSM Programs	2.2	4.5	6.8	9.1	11.4	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 IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.4**	**13.8**	**16.2**	**18.6**	**21.1**	**25.3**	**32.3**	**40.4**	**50.7**
	DSM Programs	15.7	31.3	47.5	64.6	81.8	99.6	117.6	136.4	155.8	186.4	238.6	301.2	381.7
	Short Term Cap Purch								0.0		0.1	0.2	0.5	0.5
T	Cogeneration						76.3	248.9	345.1	345.1	440.6	674.3	974.1	1,421.5
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**176.0**	**366.4**	**481.6**	**500.9**	**627.1**	**913.1**	**1,275.7**	**1,803.7**
S	**Native Load**	5,417.0	5,484.0	5,495.1	5,648.1	5,770.0	5,913.0	6,068.0	6,248.1	6,363.1	6,498.1	6,955.9	7,412.0	7,889.2
Y	**Pump Storage/Peak Ret**	309.4	309.8	307.1	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	875.2	980.8	1,138.7	1,188.9	1,232.8	1,201.0	1,274.4	1,249.6	1,319.2	1,268.4	1,272.5	1,204.4	1,208.0
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(64.6)	(81.8)	(99.6)	(117.6)	(136.4)	(155.7)	(186.4)	(238.6)	(301.2)	(381.7)
M	**Total Requirements**	8,980.2	9,015.0	8,898.9	8,825.3	8,739.1	8,699.2	8,878.1	8,903.8	8,906.9	8,922.6	9,168.7	9,386.7	9,743.0
	Existing Generation	7,774.5	7,714.3	7,619.9	7,562.4	7,711.4	7,812.9	7,815.1	7,764.6	7,760.4	7,686.5	7,700.6	7,595.1	7,541.1
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	336.4	330.8	314.1	299.2	315.0	314.0	328.6	328.2	335.5	329.5	346.5	373.1	371.4
R	**New Resources**						76.3	248.9	345.1	345.1	440.7	674.5	974.5	1,422.0
	Total Resources	8,980.2	9,015.0	8,898.9	8,825.3	8,739.1	8,699.2	8,878.1	8,903.8	8,906.9	8,922.5	9,168.7	9,386.7	9,743.0

125 MW OWC Industrial Customer Load Loss in 1999

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,804	5,957	6,078	6,221	6,377	6,557	6,672	6,807	7,264	7,720	8,198
			Conservation (MWa)	16	31	48	65	82	100	118	136	156	186	239	301	382
			After Conservation													
			System Load (MWa)	5,710	5,761	5,756	5,892	5,997	6,122	6,259	6,420	6,516	6,620	7,026	7,419	7,816
	0.62		Energy Sales (MWa)	5,159	5,256	5,255	5,365	5,477	5,592	5,709	5,818	5,890	5,943	6,254	6,583	6,969
			Total Customers (000's)	1,339	1,357	1,379	1,404	1,427	1,451	1,475	1,500	1,524	1,547	1,621	1,689	1,794
			Net Electric Plant ($M)	8,012	8,178	8,398	8,601	8,868	9,172	9,408	9,640	9,912	10,126	11,205	12,338	14,267
			Net Conservation Assets ($M)	16	32	48	63	77	90	102	115	128	144	180	208	242
			Utility Cost													
45,467	3.22	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,269	2,342	2,434	2,435	2,520	2,648	2,767	2,903	3,244	3,758	4,371
	0.22	Real		2,146	2,126	2,139	2,143	2,162	2,101	2,110	2,153	2,185	2,225	2,275	2,412	2,493
	2.59	Nominal	Cost in mills/kWh	47.5	47.6	49.3	49.8	50.7	49.7	50.4	52.0	53.6	55.8	59.2	65.2	71.6
	-0.40	Real		47.5	46.2	46.5	45.6	45.1	42.9	42.2	42.3	42.3	42.8	41.5	41.8	40.8
		Nominal	Average Customer Bill ($)	1,602	1,614	1,645	1,668	1,705	1,678	1,708	1,766	1,816	1,877	2,001	2,224	2,436
		Real		1,602	1,567	1,551	1,526	1,515	1,448	1,430	1,436	1,434	1,438	1,404	1,428	1,389
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.1	-43.6	-75.9	-131.0
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-19.0	-37.4	-78.6
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.3	26.2	30.8
44,935	3.124	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,273	2,348	2,441	2,444	2,529	2,659	2,778	2,913	3,247	3,746	4,323
	0.12	Real		2,147	2,129	2,143	2,149	2,169	2,108	2,118	2,162	2,193	2,233	2,277	2,405	2,465
	2.38	Nominal	Cost in mills/kWh	47.4	47.4	49.0	49.4	50.2	49.1	49.6	51.1	52.6	54.4	57.3	62.3	67.4
	-0.60	Real		47.4	46.0	46.2	45.2	44.6	42.3	41.6	41.5	41.5	41.7	40.2	40.0	38.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.06**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.18**

125 MW OWC Industrial Customer Load Loss in 1999

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,026	50,480	50,412	51,176	52,094	53,189	54,390	55,803	56,624	57,538	61,092	64,539	68,013
	MWa	5,711	5,763	5,755	5,842	5,947	6,072	6,209	6,370	6,464	6,568	6,974	7,367	7,764
	Total Annual Emissions (1000 Tons)													
0.57%	CO2	56,584	56,898	56,296	56,771	56,901	56,766	57,217	57,486	57,822	58,517	59,905	61,946	63,038
-0.03%	NOx	132.6	131.7	129.5	129.3	131.5	132.6	132.6	131.6	131.5	131.7	131.9	132.6	131.7
0.06%	TSP	11.8	11.7	11.6	11.6	11.8	11.8	11.8	11.8	11.8	11.9	11.9	12.0	11.9
	Annual System Emission Rates (Pounds/MWh)													
-1.04%	CO2	2,262	2,254	2,233	2,219	2,185	2,135	2,104	2,060	2,042	2,034	1,961	1,920	1,854
-1.64%	NOx	5.30	5.22	5.14	5.05	5.05	4.99	4.87	4.72	4.65	4.58	4.32	4.11	3.87
-1.54%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.42	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.73	98.07	96.57	94.36	93.00	91.08	90.28	89.91	86.69	84.86	81.94
	NOx	100	98.43	96.96	95.34	95.26	94.08	91.98	88.96	87.65	86.37	81.48	77.51	73.09
	TSP	100	98.60	97.88	96.46	95.81	93.97	91.92	89.52	88.41	87.34	82.57	78.65	74.41

20 Year Emissions (1000 Tons)	Average	Total
CO2	59,195	1,183,897
NOx	132	2,635
TSP	12	237

125 MW Utah Industrial Customer
Load Loss in 1999
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch								10.0		59.1	183.4	434.0	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
	OWC Geothermal													
O	OWC Cogen 1													95.1
W	OWC Cogen 2						122.1	172.6	125.2		130.7	256.9	350.0	149.1
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**129.8**	**180.4**	**133.3**	**8.0**	**143.2**	**277.5**	**374.4**	**274.8**
	DSM Programs	0.6	0.5	0.5	0.6	0.6	0.6	0.5	0.6	0.6	1.0	1.7	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.5**	**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	14.3	22.3	39.1	47.3	61.4
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													269.1
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**13.0**	**13.7**	**14.3**	**22.3**	**39.1**	**47.3**	**330.5**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	2.9	3.0	3.0	3.1	5.2	8.3	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**2.9**	**3.0**	**3.0**	**3.1**	**5.2**	**8.3**	**9.5**	**11.9**
T	DSM Programs	21.7	21.6	22.2	23.3	23.6	24.2	24.3	25.4	26.0	41.0	69.7	83.1	106.3
O	Short Term Cap Purch								10.0		59.1	183.4	434.0	500.0
T	Cogeneration						122.1	172.6	125.2		130.7	256.9	350.0	513.3
A	Combined Cycle CT													
L	All Others													
	Total	**21.7**	**21.6**	**22.2**	**23.3**	**23.6**	**146.3**	**196.9**	**160.6**	**26.0**	**230.8**	**510.0**	**867.1**	**1,119.6**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,313	7,403	7,430	7,646	7,815	8,012	8,226	8,475	8,633	8,819	9,451	10,079	10,738
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)	(212)	(253)	(323)	(406)	(513)
T	**Total Requirements**	**9,873**	**10,008**	**9,733**	**9,852**	**9,636**	**9,683**	**9,843**	**9,867**	**9,791**	**9,928**	**10,240**	**10,660**	**11,167**
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								10		59	183	434	500
&	New Resources						122	295	420	420	551	808	1,157	1,671
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,962**	**10,948**	**10,800**	**10,958**	**10,854**	**10,848**	**10,921**	**11,264**	**11,726**	**12,285**
	Reserves	1,223	1,178	1,398	1,109	1,313	1,117	1,114	987	1,057	993	1,024	1,066	1,117
	Reserve Margin (RM) (%	12.4	11.8	14.4	11.3	13.6	11.5	11.3	10.0	10.8	10.0	10.0	10.0	10.0

125 MW Utah Industrial Customer
Load Loss in 1999
Cumulative Annual Energy (MWa)

		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													94.2
W	OWC Cogen 2						118.7	263.9	376.0	376.0	468.6	687.3	985.1	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**152.3**	**303.7**	**422.2**	**428.5**	**531.0**	**765.9**	**1,083.1**	**1,328.6**
	DSM Programs	0.4	0.9	1.3	1.7	2.2	2.6	3.1	3.6	4.0	4.8	6.2	7.8	9.7
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.2**	**2.6**	**3.1**	**3.6**	**4.0**	**4.8**	**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	93.7	121.2	154.8	198.7
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													229.1
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.0**	**78.1**	**93.7**	**121.2**	**154.8**	**427.8**
	DSM Programs	2.2	4.5	6.8	9.1	11.4	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 IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.4**	**13.8**	**16.2**	**18.6**	**21.1**	**25.3**	**32.3**	**40.4**	**50.7**
	DSM Programs	15.7	31.3	47.5	64.6	81.8	99.6	117.6	136.4	155.7	186.2	238.3	300.9	381.5
	Short Term Cap Purch								0.0		0.1	0.2	0.4	0.5
T	Cogeneration						118.7	263.9	376.0	376.0	468.6	687.3	985.1	1,435.3
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**218.3**	**381.5**	**512.4**	**531.6**	**654.8**	**925.7**	**1,286.4**	**1,817.3**
S	**Native Load**	5,417.0	5,484.0	5,495.1	5,648.1	5,770.0	5,913.0	6,068.0	6,248.1	6,363.1	6,498.0	6,955.9	7,412.0	7,889.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.3	984.0	1,132.2	1,189.5	1,258.9	1,272.7	1,307.0	1,285.5	1,351.4	1,304.5	1,310.6	1,221.5	1,215.9
E	**DSM Programs**	(15.7)	(31.2)	(47.5)	(64.6)	(81.8)	(99.6)	(117.5)	(136.4)	(155.7)	(186.1)	(238.3)	(300.9)	(381.5)
M	**Total Requirements**	8,986.8	9,017.8	8,892.5	8,825.8	8,765.2	8,771.0	8,910.6	8,939.6	8,939.2	8,958.8	9,207.1	9,404.1	9,751.1
	Existing Generation	7,774.0	7,713.9	7,609.2	7,541.5	7,709.6	7,803.2	7,814.9	7,747.3	7,744.2	7,669.2	7,697.9	7,593.7	7,527.5
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	711.5	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.5	334.0	318.3	320.6	344.2	353.1	346.3	350.5	353.1	355.1	374.7	380.9	379.2
R	**New Resources**						118.6	263.9	376.0	375.9	468.7	687.5	985.5	1,435.8
	Total Resources	8,986.8	9,017.9	8,892.5	8,825.8	8,765.2	8,771.0	8,910.6	8,939.6	8,939.2	8,958.8	9,207.1	9,404.1	9,751.1

125 MW Utah Industrial Customer
Load Loss in 1999

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,804	5,957	6,078	6,221	6,377	6,557	6,672	6,807	7,264	7,720	8,198
			Conservation (MWa)	16	31	48	65	82	100	118	136	156	186	238	301	382
			After Conservation													
			System Load (MWa)	5,710	5,761	5,756	5,892	5,997	6,122	6,259	6,420	6,516	6,620	7,026	7,420	7,816
	0.62		Energy Sales (MWa)	5,159	5,256	5,255	5,365	5,477	5,592	5,709	5,818	5,890	5,943	6,254	6,583	6,969
			Total Customers (000's)	1,339	1,357	1,379	1,404	1,427	1,451	1,475	1,500	1,524	1,547	1,621	1,689	1,794
			Net Electric Plant ($M)	8,012	8,178	8,400	8,617	8,895	9,192	9,434	9,667	9,934	10,149	11,209	12,338	14,319
			Net Conservation Assets ($M)	16	32	48	63	77	90	102	115	128	144	179	208	242
			Utility Cost													
45,459	3.22	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,269	2,343	2,434	2,434	2,524	2,643	2,770	2,900	3,246	3,755	4,369
	0.22	Real		2,146	2,126	2,139	2,144	2,162	2,100	2,114	2,149	2,187	2,223	2,276	2,410	2,491
	2.59	Nominal	Cost in mills/kWh	47.5	47.6	49.3	49.9	50.7	49.7	50.5	51.9	53.7	55.7	59.2	65.1	71.6
	-0.40	Real		47.5	46.2	46.5	45.6	45.1	42.9	42.3	42.2	42.4	42.7	41.6	41.8	40.8
		Nominal	Average Customer Bill ($)	1,602	1,614	1,646	1,669	1,705	1,678	1,711	1,762	1,818	1,874	2,003	2,223	2,435
		Real		1,602	1,567	1,551	1,527	1,515	1,447	1,433	1,433	1,435	1,437	1,405	1,427	1,388
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.1	-43.6	-75.9	-131.0
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-19.0	-37.4	-78.6
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.2	26.2	30.8
44,927	3.122	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,274	2,349	2,441	2,443	2,534	2,654	2,780	2,910	3,249	3,744	4,321
	0.12	Real		2,147	2,129	2,143	2,150	2,169	2,107	2,122	2,158	2,195	2,230	2,279	2,403	2,464
	2.38	Nominal	Cost in mills/kWh	47.4	47.4	49.0	49.4	50.2	49.1	49.7	51.0	52.6	54.3	57.3	62.3	67.4
	-0.60	Real		47.4	46.0	46.2	45.2	44.6	42.3	41.6	41.4	41.5	41.6	40.2	40.0	38.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.05**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.17**

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125 MW Utah Industrial Customer Load Loss in 1999

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,022	50,476	50,412	51,175	52,093	53,190	54,390	55,802	56,624	57,539	61,095	64,541	68,014
	MWa	5,710	5,762	5,755	5,842	5,947	6,072	6,209	6,370	6,464	6,568	6,974	7,368	7,764
	Total Annual Emissions (1000 Tons)													
0.56%	CO2	56,584	56,898	56,232	56,648	56,893	56,667	57,210	57,409	57,713	58,411	59,888	61,936	62,889
-0.04%	NOx	132.6	131.7	129.3	128.9	131.5	132.3	132.6	131.3	131.2	131.4	131.9	132.5	131.5
0.06%	TSP	11.8	11.7	11.6	11.6	11.8	11.8	11.8	11.8	11.8	11.8	11.9	12.0	11.9
	Annual System Emission Rates (Pounds/MWh)													
-1.06%	CO2	2,262	2,254	2,231	2,214	2,184	2,131	2,104	2,058	2,038	2,030	1,960	1,919	1,849
-1.65%	NOx	5.30	5.22	5.13	5.04	5.05	4.98	4.87	4.71	4.63	4.57	4.32	4.11	3.87
-1.55%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.42	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.61	97.86	96.55	94.18	92.99	90.95	90.10	89.74	86.66	84.83	81.74
	NOx	100	98.42	96.78	95.02	95.23	93.88	91.97	88.79	87.42	86.14	81.44	77.49	72.93
	TSP	100	98.60	97.66	96.08	95.76	93.77	91.91	89.35	88.04	86.99	82.50	78.76	74.32

20 Year Emissions (1000 Tons)	Average	Total
CO2	59,137	1,182,738
NOx	132	2,632
TSP	12	237

125 MW Wyoming Industrial Customer Load Loss in 1999

Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch								11.2		58.4	167.8	425.3	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
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2						112.4	189.2	117.1		132.9	271.9	343.1	140.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**120.1**	**197.0**	**125.2**	**8.0**	**145.4**	**292.5**	**367.5**	**170.6**
	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.5	0.6	1.0	1.6	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.5**	**0.6**	**1.0**	**1.6**	**1.9**	**2.4**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	13.0	13.7	14.3	22.7	39.3	47.3	61.4
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													364.7
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**13.0**	**13.7**	**14.3**	**22.7**	**39.3**	**47.3**	**426.1**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	2.9	3.0	3.0	3.1	4.6	8.1	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**2.9**	**3.0**	**3.0**	**3.1**	**4.6**	**8.1**	**9.5**	**11.9**
T	DSM Programs	21.7	21.6	22.3	23.2	23.6	24.2	24.4	25.3	26.0	40.8	69.6	83.1	106.3
O	Short Term Cap Purch								11.2		58.4	167.8	425.3	500.0
T	Cogeneration						112.4	189.2	117.1		132.9	271.9	343.1	504.7
A	Combined Cycle CT													
L	All Others													
	Total	**21.7**	**21.6**	**22.3**	**23.2**	**23.6**	**136.6**	**213.6**	**153.6**	**26.0**	**232.1**	**509.3**	**851.5**	**1,111.0**
	Annual Summer Peak Capacity (MW)													
S	Native Load	7,313	7,403	7,430	7,646	7,815	8,012	8,226	8,475	8,633	8,819	9,451	10,079	10,738
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)	(212)	(253)	(323)	(406)	(512)
T	**Total Requirements**	**9,873**	**10,008**	**9,733**	**9,852**	**9,636**	**9,683**	**9,843**	**9,867**	**9,791**	**9,928**	**10,240**	**10,660**	**11,168**
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								11		58	168	425	500
&	New Resources						112	302	419	419	552	823	1,167	1,671
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,962**	**10,948**	**10,790**	**10,965**	**10,854**	**10,847**	**10,921**	**11,264**	**11,727**	**12,285**
	Reserves	1,223	1,178	1,398	1,109	1,313	1,107	1,121	987	1,056	993	1,024	1,066	1,117
	Reserve Margin (RM) (%	12.4	11.8	14.4	11.3	13.6	11.4	11.4	10.0	10.8	10.0	10.0	10.0	10.0

125 MW Wyoming Industrial Customer Load Loss in 1999

Cumulative Annual Energy (MWa)

		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													
W	OWC Cogen 2						109.4	270.1	374.9	374.9	469.5	700.9	992.8	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**143.0**	**309.9**	**421.1**	**427.4**	**531.8**	**779.5**	**1,090.8**	**1,234.4**
	DSM Programs	0.4	0.9	1.3	1.7	2.2	2.7	3.1	3.6	4.0	4.8	6.1	7.6	9.6
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.2**	**2.7**	**3.1**	**3.6**	**4.0**	**4.8**	**6.1**	**7.6**	**9.6**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	68.0	78.1	94.0	121.6	155.3	199.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													310.4
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.0**	**78.1**	**94.0**	**121.6**	**155.3**	**509.5**
	DSM Programs	2.2	4.5	6.8	9.1	11.4	13.8	16.2	18.6	21.1	24.7	31.4	39.5	49.8
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.4**	**13.8**	**16.2**	**18.6**	**21.1**	**24.7**	**31.4**	**39.5**	**49.8**
	DSM Programs	15.7	31.3	47.5	64.6	81.8	99.6	117.6	136.4	155.7	185.8	237.7	300.4	380.9
	Short Term Cap Purch								0.0		0.1	0.2	0.4	0.5
T	Cogeneration						109.4	270.1	374.9	374.9	469.5	700.9	992.8	1,422.4
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**209.0**	**387.6**	**511.3**	**530.6**	**655.3**	**938.8**	**1,293.6**	**1,803.8**
S	**Native Load**	5,417.0	5,484.0	5,495.1	5,648.1	5,770.0	5,913.0	6,068.1	6,248.1	6,363.1	6,498.1	6,955.9	7,412.0	7,889.2
Y	**Pump Storage/Peak Ret**	310.0	288.1	307.1	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	874.7	980.8	1,135.5	1,167.9	1,227.8	1,210.3	1,273.1	1,233.9	1,307.2	1,276.5	1,282.0	1,213.1	1,203.8
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(64.6)	(81.8)	(99.6)	(117.6)	(136.4)	(155.7)	(185.7)	(237.7)	(300.4)	(380.9)
M	**Total Requirements**	8,980.3	8,993.4	8,895.8	8,804.3	8,734.1	8,708.5	8,876.8	8,888.0	8,895.0	8,931.2	9,179.0	9,396.3	9,739.6
	Existing Generation	7,775.1	7,692.6	7,614.1	7,545.6	7,711.0	7,796.8	7,805.5	7,741.8	7,733.6	7,662.8	7,683.5	7,583.2	7,533.7
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	335.8	330.8	316.7	295.0	310.4	306.2	315.6	305.5	320.7	333.0	347.4	375.9	374.3
R	**New Resources**						109.4	270.1	374.9	374.8	469.5	701.0	993.3	1,422.9
	Total Resources	8,980.3	8,993.4	8,895.7	8,804.3	8,734.1	8,708.5	8,876.8	8,888.0	8,895.0	8,931.2	9,179.0	9,396.3	9,739.6

125 MW Wyoming Industrial Customer Load Loss in 1999

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,804	5,957	6,078	6,221	6,377	6,557	6,672	6,807	7,264	7,720	8,198
			Conservation (MWa)	16	31	48	65	82	100	118	136	156	186	238	300	381
			After Conservation													
			System Load (MWa)	5,710	5,761	5,756	5,892	5,997	6,122	6,259	6,420	6,516	6,621	7,027	7,420	7,817
	0.62		Energy Sales (MWa)	5,159	5,256	5,255	5,365	5,477	5,592	5,709	5,818	5,890	5,943	6,255	6,584	6,969
			Total Customers (000's)	1,339	1,357	1,379	1,404	1,427	1,451	1,475	1,500	1,524	1,547	1,621	1,689	1,794
			Net Electric Plant ($M)	8,012	8,178	8,399	8,614	8,893	9,195	9,433	9,667	9,935	10,151	11,224	12,345	14,246
			Net Conservation Assets ($M)	16	32	48	63	77	90	102	115	128	144	179	208	241
			Utility Cost													
45,472	3.22	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,269	2,343	2,434	2,436	2,525	2,646	2,772	2,902	3,244	3,759	4,375
	0.22	Real		2,146	2,126	2,139	2,144	2,163	2,101	2,114	2,152	2,188	2,224	2,275	2,413	2,495
	2.59	Nominal	Cost in mills/kWh	47.5	47.6	49.3	49.9	50.7	49.7	50.5	51.9	53.7	55.7	59.2	65.2	71.7
	-0.40	Real		47.5	46.2	46.5	45.6	45.1	42.9	42.3	42.2	42.4	42.7	41.5	41.8	40.9
		Nominal	Average Customer Bill ($)	1,602	1,614	1,646	1,669	1,706	1,679	1,711	1,764	1,819	1,875	2,002	2,225	2,438
		Real		1,602	1,567	1,551	1,527	1,515	1,448	1,433	1,434	1,436	1,437	1,404	1,428	1,390
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.1	-43.7	-75.9	-131.1
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-19.0	-37.4	-78.6
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.2	26.2	30.7
44,940	3.124	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,273	2,349	2,442	2,444	2,534	2,657	2,782	2,911	3,247	3,747	4,327
	0.12	Real		2,147	2,129	2,143	2,150	2,169	2,109	2,122	2,160	2,196	2,231	2,278	2,405	2,468
	2.38	Nominal	Cost in mills/kWh	47.4	47.4	49.0	49.4	50.2	49.1	49.7	51.0	52.6	54.4	57.3	62.4	67.5
	-0.60	Real		47.4	46.0	46.2	45.2	44.6	42.3	41.7	41.5	41.6	41.7	40.2	40.0	38.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.06**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.18**

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125 MW Wyoming Industrial Customer Load Loss in 1999

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,031	50,290	50,412	51,176	52,093	53,189	54,391	55,802	56,625	57,543	61,099	64,546	68,019
	MWa	5,711	5,741	5,755	5,842	5,947	6,072	6,209	6,370	6,464	6,569	6,975	7,368	7,765
	Total Annual Emissions (1000 Tons)													
0.57%	CO2	56,584	56,898	56,262	56,672	56,901	56,659	57,153	57,357	57,659	58,365	59,794	61,870	62,996
-0.04%	NOx	132.6	131.7	129.4	129.0	131.5	132.3	132.4	131.1	131.0	131.2	131.6	132.3	131.6
0.06%	TSP	11.8	11.7	11.6	11.6	11.8	11.7	11.8	11.7	11.7	11.8	11.9	11.9	11.9
	Annual System Emission Rates (Pounds/MWh)													
-1.05%	CO2	2,262	2,263	2,232	2,215	2,185	2,130	2,102	2,056	2,037	2,029	1,957	1,917	1,852
-1.64%	NOx	5.30	5.24	5.13	5.04	5.05	4.97	4.87	4.70	4.63	4.56	4.31	4.10	3.87
-1.55%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	100.04	98.68	97.92	96.58	94.19	92.91	90.88	90.03	89.68	86.53	84.75	81.89
	NOx	100	98.81	96.88	95.09	95.27	93.85	91.85	88.70	87.31	86.04	81.26	77.37	73.01
	TSP	100	98.98	97.77	96.16	95.81	93.67	91.76	89.21	87.92	86.88	82.26	78.44	74.33

20 Year Emissions (1000 Tons)	Average	Total
CO2	59,115	1,182,293
NOx	132	2,630
TSP	12	236

125 MW Idaho Industrial Customer
Load Loss in 1999
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch								38.0		80.2	186.1	435.0	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
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2						91.1	197.9	102.9		137.3	275.2	351.6	150.6
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**98.8**	**205.7**	**111.0**	**8.0**	**149.8**	**295.8**	**376.0**	**181.2**
	DSM Programs	0.6	0.5	0.5	0.6	0.6	0.6	0.5	0.6	0.6	0.9	1.7	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.5**	**0.6**	**0.6**	**0.9**	**1.7**	**1.9**	**2.4**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	13.0	13.7	14.3	22.7	39.3	47.3	61.4
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													363.8
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**13.0**	**13.7**	**14.3**	**22.7**	**39.3**	**47.3**	**425.2**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	2.9	3.0	3.0	3.1	5.2	8.3	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**2.9**	**3.0**	**3.0**	**3.1**	**5.2**	**8.3**	**9.5**	**11.9**
T	DSM Programs	21.7	21:6	22.2	23.3	23.6	24.2	24.3	25.4	26.0	41.3	69.9	83.1	106.3
O	Short Term Cap Purch								38.0		80.2	186.1	435.0	500.0
T	Cogeneration						91.1	197.9	102.9		137.3	275.2	351.6	514.4
A	Combined Cycle CT													
L	All Others													
	Total	**21.7**	**21.6**	**22.2**	**23.3**	**23.6**	**115.3**	**222.2**	**166.3**	**26.0**	**258.8**	**531.2**	**869.7**	**1,120.7**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,313	7,403	7,430	7,646	7,815	8,012	8,226	8,475	8,633	8,819	9,451	10,079	10,738
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)	(212)	(254)	(324)	(407)	(513)
T	**Total Requirements**	**9,873**	**10,008**	**9,733**	**9,852**	**9,636**	**9,683**	**9,843**	**9,867**	**9,791**	**9,927**	**10,239**	**10,659**	**11,167**
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								38		80	186	435	500
&	New Resources						91	289	392	392	529	804	1,156	1,670
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,962**	**10,948**	**10,769**	**10,952**	**10,854**	**10,820**	**10,920**	**11,263**	**11,726**	**12,284**
	Reserves	1,223	1,178	1,398	1,109	1,313	1,086	1,108	987	1,029	993	1,024	1,066	1,117
	Reserve Margin (RM) (%	12.4	11.8	14.4	11.3	13.6	11.2	11.3	10.0	10.5	10.0	10.0	10.0	10.0

125 MW Idaho Industrial Customer
Load Loss in 1999
Cumulative Annual Energy (MWa)

		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													
W	OWC Cogen 2						88.6	258.8	350.9	350.9	450.4	684.6	983.8	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**122.3**	**298.6**	**397.1**	**403.4**	**512.7**	**763.2**	**1,081.8**	**1,234.4**
	DSM Programs	0.4	0.9	1.3	1.7	2.2	2.6	3.1	3.6	4.0	4.7	6.1	7.6	9.6
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.2**	**2.6**	**3.1**	**3.6**	**4.0**	**4.7**	**6.1**	**7.6**	**9.6**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	68.0	78.1	94.0	121.6	155.3	199.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													309.6
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.0**	**78.1**	**94.0**	**121.6**	**155.3**	**508.7**
	DSM Programs	2.2	4.5	6.8	9.1	11.4	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 IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.4**	**13.8**	**16.2**	**18.6**	**21.1**	**25.3**	**32.3**	**40.4**	**50.7**
	DSM Programs	15.7	31.3	47.5	64.6	81.8	99.6	117.6	136.4	155.7	186.3	238.5	301.2	381.8
	Short Term Cap Purch								0.0		0.1	0.2	0.4	0.5
T	Cogeneration						88.6	258.8	350.9	350.9	450.4	684.6	983.8	1,421.6
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**188.2**	**376.3**	**487.3**	**506.6**	**636.8**	**923.3**	**1,285.4**	**1,803.9**
S	**Native Load**	5,417.0	5,484.0	5,495.1	5,648.1	5,770.0	5,913.0	6,068.1	6,248.1	6,363.1	6,498.1	6,955.9	7,412.0	7,889.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.3	984.0	1,136.0	1,203.0	1,259.5	1,250.3	1,302.0	1,273.9	1,340.7	1,300.3	1,308.1	1,219.0	1,213.2
E	**DSM Programs**	(15.7)	(31.2)	(47.5)	(64.6)	(81.8)	(99.6)	(117.5)	(136.4)	(155.7)	(186.3)	(238.5)	(301.2)	(381.8)
M	**Total Requirements**	8,986.8	9,017.8	8,896.3	8,839.4	8,765.8	8,748.5	8,905.6	8,928.0	8,928.5	8,954.5	9,204.3	9,401.3	9,748.1
	Existing Generation	7,774.0	7,713.9	7,617.9	7,553.2	7,706.7	7,812.2	7,816.4	7,760.5	7,758.2	7,680.2	7,695.9	7,589.4	7,539.1
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.5	334.0	313.5	322.5	346.3	351.6	344.9	350.7	353.6	357.9	376.5	383.8	378.3
R	**New Resources**						88.6	258.8	350.9	350.9	450.5	684.8	984.2	1,422.1
	Total Resources	8,986.8	9,017.9	8,896.3	8,839.4	8,765.8	8,748.5	8,905.6	8,928.0	8,928.5	8,954.4	9,204.3	9,401.3	9,748.1

125 MW Idaho Industrial Customer Load Loss in 1999

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,804	5,957	6,078	6,221	6,377	6,557	6,672	6,807	7,264	7,720	8,198
			Conservation (MWa)	16	31	48	65	82	100	118	136	156	186	239	301	382
			After Conservation													
			System Load (MWa)	5,710	5,761	5,756	5,892	5,997	6,122	6,259	6,420	6,516	6,620	7,026	7,419	7,816
	0.62		Energy Sales (MWa)	5,159	5,256	5,255	5,365	5,477	5,592	5,709	5,818	5,890	5,943	6,254	6,583	6,969
			Total Customers (000's)	1,339	1,357	1,379	1,404	1,427	1,451	1,475	1,500	1,524	1,547	1,621	1,689	1,794
			Net Electric Plant ($M)	8,012	8,178	8,398	8,606	8,878	9,179	9,413	9,647	9,920	10,135	11,214	12,345	14,259
			Net Conservation Assets ($M)	16	32	48	63	77	90	102	115	128	144	180	208	242
			Utility Cost													
45,460	3.22	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,269	2,342	2,434	2,435	2,520	2,648	2,768	2,901	3,243	3,757	4,372
	0.22	Real		2,146	2,126	2,139	2,144	2,162	2,100	2,111	2,153	2,185	2,224	2,274	2,411	2,493
	2.59	Nominal	Cost in mills/kWh	47.5	47.6	49.3	49.8	50.7	49.7	50.4	52.0	53.6	55.7	59.2	65.1	71.6
	-0.40	Real		47.5	46.2	46.5	45.6	45.1	42.9	42.2	42.3	42.4	42.7	41.5	41.8	40.8
		Nominal	Average Customer Bill ($)	1,602	1,614	1,646	1,668	1,705	1,678	1,708	1,766	1,816	1,875	2,001	2,224	2,436
		Real		1,602	1,567	1,551	1,527	1,515	1,448	1,431	1,436	1,434	1,437	1,403	1,427	1,389
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.0	-43.6	-75.7	-130.5
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-18.9	-37.3	-78.4
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.3	26.2	30.8
44,929	3.123	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,274	2,348	2,441	2,443	2,530	2,659	2,778	2,911	3,246	3,745	4,324
	0.12	Real		2,147	2,129	2,143	2,149	2,169	2,108	2,119	2,162	2,193	2,231	2,277	2,404	2,466
	2.38	Nominal	Cost in mills/kWh	47.4	47.4	49.0	49.4	50.2	49.1	49.7	51.1	52.6	54.4	57.2	62.3	67.5
	-0.60	Real		47.4	46.0	46.2	45.2	44.6	42.3	41.6	41.5	41.5	41.7	40.2	40.0	38.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.05**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.17**

125 MW Idaho Industrial Customer Load Loss in 1999

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,022	50,476	50,412	51,176	52,093	53,189	54,391	55,802	56,625	57,538	61,092	64,538	68,012
	MWa	5,710	5,762	5,755	5,842	5,947	6,072	6,209	6,370	6,464	6,568	6,974	7,367	7,764
	Total Annual Emissions (1000 Tons)													
0.57%	CO_2	56,584	56,898	56,284	56,717	56,874	56,758	57,221	57,474	57,807	58,474	59,874	61,909	63,026
-0.03%	NO_x	132.6	131.7	129.5	129.1	131.4	132.6	132.6	131.5	131.5	131.6	131.8	132.5	131.7
0.06%	TSP	11.8	11.7	11.6	11.6	11.8	11.8	11.8	11.8	11.8	11.8	11.9	12.0	11.9
	Annual System Emission Rates (Pounds/MWh)													
-1.04%	CO_2	2,262	2,254	2,233	2,217	2,184	2,134	2,104	2,060	2,042	2,033	1,960	1,919	1,853
-1.64%	NO_x	5.30	5.22	5.14	5.05	5.05	4.99	4.88	4.71	4.64	4.57	4.32	4.10	3.87
-1.54%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.42	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO_2	100	99.65	98.70	97.97	96.51	94.33	93.00	91.05	90.25	89.84	86.64	84.80	81.92
	NO_x	100	98.42	96.92	95.19	95.18	94.06	91.99	88.93	87.61	86.27	81.42	77.44	73.07
	TSP	100	98.60	97.74	96.24	95.78	93.95	91.97	89.47	88.36	87.26	82.55	78.69	74.44

20 Year Emissions (1000 Tons)	Average	Total
CO_2	59,172	1,183,436
NO_x	132	2,634
TSP	12	237

Utah with 4 Percent Load Growth

Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				154.8				27.5	21.3	282.0	482.6	500.0	500.0
	DSM Programs	6.8	7.1	7.0	7.7	7.6	8.0	8.1	8.4	8.4	12.5	21.0	25.0	31.3
	OWC Geothermal													
O	OWC Cogen 1													31.5
W	OWC Cogen 2						317.4	226.4	235.7		76.7	275.0	175.4	
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT												129.3	247.7
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.7**	**7.6**	**325.4**	**234.5**	**244.1**	**8.4**	**89.2**	**296.0**	**329.7**	**310.5**
	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
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	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	12.7	12.3	13.7	13.7	14.1	14.8	22.8	39.5	47.4	61.5
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2											90.8	548.2	880.0
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.7**	**12.3**	**13.7**	**13.7**	**14.1**	**14.8**	**22.8**	**130.3**	**595.6**	**941.5**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	3.0	3.0	3.0	3.0	5.2	8.4	9.4	12.0
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**5.2**	**8.4**	**9.4**	**12.0**
T	DSM Programs	21.7	21.6	22.3	23.7	23.5	25.3	25.4	26.1	26.8	41.5	70.6	83.7	107.2
O	Short Term Cap Purch				154.8				27.5	21.3	282.0	482.6	500.0	500.0
T	Cogeneration						317.4	226.4	235.7		76.7	365.8	723.6	911.5
A	Combined Cycle CT													
L	All Others												129.3	247.7
	Total	**21.7**	**21.6**	**22.3**	**178.5**	**23.5**	**342.7**	**251.8**	**289.3**	**48.1**	**400.2**	**919.0**	**1,436.6**	**1,766.4**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,313	7,504	7,698	7,900	8,101	8,326	8,573	8,821	9,054	9,304	10,105	10,979	12,166
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)	(113)	(138)	(163)	(190)	(216)	(258)	(328)	(412)	(519)
T	**Total Requirements**	**9,873**	**10,109**	**10,001**	**10,106**	**9,921**	**9,996**	**10,188**	**10,209**	**10,208**	**10,408**	**10,889**	**11,554**	**12,589**
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				155				28	21	282	483	500	500
&	New Resources						317	544	780	780	856	1,222	2,075	3,234
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**11,117**	**10,948**	**10,995**	**11,207**	**11,232**	**11,229**	**11,449**	**11,978**	**12,710**	**13,848**
	Reserves	1,223	1,077	1,130	1,011	1,027	1,000	1,019	1,021	1,021	1,041	1,089	1,155	1,259
	Reserve Margin (RM) (%	12.4	10.7	11.3	10.0	10.4	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Utah with 4 Percent Load Growth

Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.2	10.5	15.9	21.9	28.0	34.1	40.4	47.0	53.6	63.4	80.0	99.8	124.7
	OWC Geothermal													
O	OWC Cogen 1													31.2
W	OWC Cogen 2						308.4	486.9	697.9	697.9	728.7	962.7	1,112.0	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT												33.3	77.5
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.9**	**28.0**	**342.5**	**527.3**	**744.9**	**751.5**	**792.1**	**1,042.7**	**1,245.0**	**1,345.4**
	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
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	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	50.2	59.7	69.6	80.0	96.0	123.7	157.4	201.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2											77.2	543.8	1,292.8
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**50.2**	**59.7**	**69.6**	**80.0**	**96.0**	**201.0**	**701.2**	**1,494.0**
	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 IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	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**
	DSM Programs	15.7	31.3	47.5	65.0	82.2	100.8	119.5	138.8	158.7	189.6	242.2	305.3	386.4
	Short Term Cap Purch				0.1				0.0	0.0	0.3	0.5	0.5	0.5
T	Cogeneration						308.4	486.9	697.9	697.9	728.7	1,040.0	1,655.8	2,436.0
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle												33.3	77.5
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**65.1**	**82.2**	**409.2**	**606.4**	**836.8**	**856.6**	**918.5**	**1,282.7**	**1,994.9**	**2,900.4**
S	**Native Load**	5,417.0	5,552.7	5,692.6	5,835.7	5,979.2	6,141.4	6,319.2	6,498.8	6,664.5	6,843.0	7,415.7	8,039.3	8,875.4
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.3	969.2	1,076.0	1,125.8	1,134.7	1,239.9	1,280.4	1,344.1	1,347.2	1,271.6	1,281.8	1,253.6	1,290.6
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(65.0)	(82.2)	(100.8)	(119.5)	(138.8)	(158.7)	(189.6)	(242.2)	(305.3)	(386.4)
M	**Total Requirements**	8,986.8	9,071.7	9,033.8	8,949.5	8,849.8	8,965.4	9,133.3	9,246.4	9,233.3	9,267.5	9,634.1	10,059.0	10,807.1
	Existing Generation	7,774.0	7,759.0	7,733.9	7,649.6	7,780.2	7,802.1	7,817.7	7,727.7	7,729.6	7,705.5	7,751.3	7,543.8	7,508.9
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	713.3	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.4	342.8	334.9	336.0	356.2	358.8	343.1	354.9	339.9	367.1	395.2	381.8	375.6
R	**New Resources**				0.1		308.4	486.9	697.9	697.9	728.9	1,040.4	1,689.6	2,514.0
	Total Resources	8,986.8	9,071.7	9,033.8	8,949.4	8,849.8	8,965.4	9,133.3	9,246.4	9,233.3	9,267.4	9,634.1	10,059.0	10,807.1

Utah with 4 Percent Load Growth

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,861	6,001	6,144	6,288	6,450	6,628	6,807	6,973	7,152	7,724	8,348	9,184
			Conservation (MWa)	16	31	48	65	82	101	120	139	159	190	242	305	386
			After Conservation													
			System Load (MWa)	5,710	5,830	5,954	6,079	6,205	6,349	6,508	6,668	6,814	6,962	7,482	8,042	8,797
	0.89		Energy Sales (MWa)	5,159	5,325	5,453	5,552	5,686	5,820	5,958	6,066	6,188	6,285	7,237	7,566	7,951
			Total Customers (000's)	1,339	1,358	1,381	1,406	1,429	1,453	1,477	1,502	1,526	1,550	1,629	1,698	1,803
			Net Electric Plant ($M)	8,012	8,178	8,418	8,695	9,088	9,447	9,736	9,938	10,186	10,384	11,573	13,227	15,809
			Net Conservation Assets ($M)	16	32	48	63	77	90	103	116	129	146	182	211	245
			Utility Cost													
47,928	3.36	Nominal	**Operating Revenues ($M)**	2,146	2,199	2,296	2,392	2,468	2,472	2,589	2,716	2,869	3,047	3,416	3,940	4,760
	0.35	Real		2,146	2,135	2,164	2,189	2,193	2,132	2,168	2,208	2,265	2,335	2,396	2,529	2,715
	2.45	Nominal	Cost in mills/kWh	47.5	47.2	48.1	49.2	49.6	48.5	49.6	51.1	52.9	55.4	53.9	59.4	68.4
	-0.54	Real		47.5	45.8	45.3	45.0	44.0	41.8	41.5	41.6	41.8	42.4	37.8	38.2	39.0
		Nominal	Average Customer Bill ($)	1,602	1,620	1,663	1,702	1,727	1,702	1,752	1,808	1,880	1,966	2,097	2,321	2,640
		Real		1,602	1,572	1,568	1,557	1,534	1,468	1,468	1,470	1,484	1,507	1,471	1,490	1,506
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.0	-43.5	-75.4	-129.9
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-18.9	-37.2	-78.2
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	11.0	13.1	15.6	16.8	18.5	22.6	26.7	31.4
47,401	3.263	Nominal	**Total Resource Cost ($M)**	2,147	2,202	2,300	2,398	2,475	2,481	2,599	2,726	2,879	3,057	3,420	3,929	4,713
	0.26	Real		2,147	2,138	2,168	2,195	2,199	2,140	2,177	2,217	2,273	2,343	2,399	2,522	2,688
	2.26	Nominal	Cost in mills/kWh	47.4	47.0	47.8	48.8	49.0	47.9	48.9	50.3	51.9	54.0	52.3	57.2	64.8
	-0.72	Real		47.4	45.6	45.0	44.6	43.6	41.3	40.9	40.9	41.0	41.4	36.7	36.7	36.9

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **40.28**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **38.61**

Utah with 4 Percent Load Growth

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,022	51,078	52,142	52,816	53,922	55,180	56,574	57,977	59,238	60,531	65,088	69,997	76,611
	MWa	5,710	5,831	5,952	6,029	6,155	6,299	6,458	6,618	6,762	6,910	7,430	7,991	8,746
	Total Annual Emissions (1000 Tons)													
0.85%	CO2	56,584	57,432	57,732	58,013	58,117	57,489	58,111	58,122	58,687	59,836	61,839	63,934	66,461
-0.02%	NOx	132.6	132.6	131.9	131.2	133.0	132.5	132.7	131.0	131.1	132.2	133.1	132.2	132.0
0.10%	TSP	11.8	11.8	11.8	11.8	11.9	11.8	11.8	11.8	11.8	11.9	12.0	12.0	12.0
	Annual System Emission Rates (Pounds/MWh)													
-1.39%	CO2	2,262	2,249	2,214	2,197	2,156	2,084	2,054	2,005	1,981	1,977	1,900	1,827	1,735
-2.24%	NOx	5.30	5.19	5.06	4.97	4.93	4.80	4.69	4.52	4.43	4.37	4.09	3.78	3.45
-2.12%	TSP	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.40	0.39	0.37	0.34	0.31
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.40	97.88	97.10	95.28	92.10	90.80	88.62	87.58	87.39	83.99	80.74	76.69
	NOx	100	97.97	95.47	93.70	93.06	90.59	88.54	85.26	83.51	82.41	77.18	71.24	65.02
	TSP	100	98.12	95.76	94.71	93.26	90.77	88.69	86.33	84.26	83.56	78.20	72.47	66.51

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,770	1,215,399
NOx	132	2,645
TSP	12	238

625 MW OWC Industrial Customer
Load Loss in 1999
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch											79.3	329.1	500.0
	DSM Programs	4.9	5.1	5.6	5.8	5.8	5.8	6.0	5.8	5.9	8.7	15.2	18.1	22.5
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2										84.8	308.7	358.3	360.6
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**4.9**	**5.1**	**5.6**	**5.8**	**5.8**	**5.8**	**6.0**	**5.8**	**5.9**	**93.5**	**323.9**	**376.4**	**383.1**
	DSM Programs	0.6	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.9	1.5	1.7	2.1
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.9**	**1.5**	**1.7**	**2.1**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	12.9	13.0	14.2	22.2	38.7	46.9	60.9
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													58.0
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													18.0
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**12.9**	**13.0**	**14.2**	**22.2**	**38.7**	**46.9**	**136.9**
	DSM Programs	2.7	2.6	2.7	2.8	3.0	2.9	3.0	3.0	3.1	4.6	8.1	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.7**	**2.6**	**2.7**	**2.8**	**3.0**	**2.9**	**3.0**	**3.0**	**3.1**	**4.6**	**8.1**	**9.5**	**11.9**
T	DSM Programs	19.7	19.4	20.7	21.8	21.6	22.3	22.5	22.4	23.8	36.4	63.5	76.2	97.4
O	Short Term Cap Purch											79.3	329.1	500.0
T	Cogeneration										84.8	308.7	358.3	418.6
A	Combined Cycle CT													
L	All Others													18.0
	Total	**19.7**	**19.4**	**20.7**	**21.8**	**21.6**	**22.3**	**22.5**	**22.4**	**23.8**	**121.2**	**451.5**	**763.6**	**1,034.0**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,313	7,403	6,930	7,146	7,315	7,512	7,726	7,975	8,133	8,319	8,951	9,579	10,238
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	(20)	(39)	(60)	(82)	(103)	(126)	(148)	(170)	(194)	(230)	(294)	(370)	(468)
T	**Total Requirements**	**9,875**	**10,012**	**9,239**	**9,359**	**9,145**	**9,194**	**9,356**	**9,383**	**9,309**	**9,451**	**9,769**	**10,196**	**10,712**
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	9,509
	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											79	329	500
&	New Resources										85	394	752	1,188
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,962**	**10,948**	**10,678**	**10,663**	**10,424**	**10,428**	**10,396**	**10,746**	**11,216**	**11,784**
	Reserves	1,221	1,174	1,892	1,602	1,804	1,484	1,307	1,041	1,119	945	977	1,020	1,071
	Reserve Margin (RM) (%	12.4	11.7	20.5	17.1	19.7	16.1	14.0	11.1	12.0	10.0	10.0	10.0	10.0

625 MW OWC Industrial Customer
Load Loss in 1999
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	3.4	7.0	11.1	15.2	19.4	23.6	28.0	32.3	36.6	43.1	54.4	67.8	84.5
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2										72.2	334.9	639.8	946.8
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**3.4**	**7.0**	**11.1**	**15.2**	**19.4**	**23.6**	**28.0**	**32.3**	**36.6**	**115.3**	**389.3**	**707.6**	**1,031.3**
	DSM Programs	0.4	0.9	1.3	1.7	2.2	2.6	3.1	3.5	4.0	4.7	5.9	7.3	8.9
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.2**	**2.6**	**3.1**	**3.5**	**4.0**	**4.7**	**5.9**	**7.3**	**8.9**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	67.4	77.4	92.9	120.3	153.7	197.3
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													49.3
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													16.8
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**67.4**	**77.4**	**92.9**	**120.3**	**153.7**	**263.5**
	DSM Programs	2.2	4.3	6.5	8.8	11.2	13.5	15.9	18.4	20.8	24.4	31.2	39.3	49.6
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.3**	**6.5**	**8.8**	**11.2**	**13.5**	**15.9**	**18.4**	**20.8**	**24.4**	**31.2**	**39.3**	**49.6**
	DSM Programs	13.8	27.6	42.4	57.9	73.3	89.2	105.3	121.5	138.8	165.2	211.7	268.0	340.3
	Short Term Cap Purch											0.1	0.3	0.5
T	Cogeneration										72.2	334.9	639.8	996.1
O	Combined Cycle CT													
T	Coal													
A	Transmission													16.8
L	Simple Cycle													
	Storage													
	Total	**13.8**	**27.6**	**42.4**	**57.9**	**73.3**	**89.2**	**105.3**	**121.5**	**138.8**	**237.3**	**546.7**	**908.1**	**1,353.7**
S	**Native Load**	5,417.0	5,484.0	5,095.1	5,248.1	5,370.0	5,513.0	5,668.0	5,848.1	5,963.1	6,098.1	6,555.9	7,012.0	7,489.2
Y	**Pump Storage/Peak Ret**	310.2	309.3	306.9	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	878.3	978.7	1,300.1	1,356.4	1,384.5	1,384.6	1,342.5	1,263.7	1,328.2	1,264.0	1,294.9	1,218.0	1,177.6
E	**DSM Programs**	(13.8)	(27.6)	(42.4)	(57.9)	(73.3)	(89.2)	(105.3)	(121.5)	(138.8)	(165.2)	(211.7)	(268.0)	(340.3)
M	**Total Requirements**	8,985.9	9,016.3	8,665.3	8,599.4	8,499.3	8,493.3	8,558.4	8,532.6	8,532.9	8,539.4	8,817.9	9,033.5	9,354.0
	Existing Generation	7,776.1	7,715.4	7,425.7	7,375.2	7,501.2	7,684.3	7,756.7	7,736.0	7,731.1	7,674.1	7,683.4	7,574.8	7,553.7
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	711.3	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	340.5	330.9	274.6	260.5	286.8	313.0	316.1	330.8	335.9	327.2	352.4	374.7	378.3
R	**New Resources**										72.2	335.0	640.1	1,013.4
	Total Resources	8,985.9	9,016.3	8,665.2	8,599.4	8,499.3	8,493.3	8,558.4	8,532.6	8,532.8	8,539.4	8,817.9	9,033.6	9,354.0

625 MW OWC Industrial Customer Load Loss in 1999

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,404	5,557	5,678	5,821	5,977	6,157	6,272	6,407	6,864	7,320	7,798
			Conservation (MWa)	14	28	43	59	74	89	104	120	136	161	206	259	326
			After Conservation													
			System Load (MWa)	5,711	5,764	5,361	5,498	5,605	5,733	5,872	6,036	6,136	6,245	6,658	7,062	7,472
	0.51		Energy Sales (MWa)	5,160	5,259	4,859	4,970	5,084	5,202	5,321	5,433	5,508	5,566	5,884	6,223	6,621
			Total Customers (000's)	1,339	1,357	1,376	1,401	1,424	1,448	1,472	1,497	1,520	1,544	1,617	1,686	1,791
			Net Electric Plant ($M)	8,010	8,175	8,390	8,557	8,710	8,880	9,064	9,288	9,535	9,767	10,905	12,067	13,838
			Net Conservation Assets ($M)	15	29	43	58	71	83	94	105	116	130	158	181	208
			Utility Cost													
44,171	3.18	Nominal	**Operating Revenues ($M)**	2,146	2,191	2,215	2,288	2,373	2,363	2,439	2,539	2,652	2,771	3,105	3,624	4,260
	0.17	Real		2,146	2,127	2,088	2,094	2,109	2,038	2,043	2,064	2,093	2,124	2,178	2,326	2,429
	2.65	Nominal	Cost in mills/kWh	47.5	47.6	52.0	52.5	53.3	51.9	52.3	53.3	55.0	56.8	60.2	66.5	73.5
	-0.34	Real		47.5	46.2	49.0	48.1	47.4	44.7	43.8	43.4	43.4	43.6	42.3	42.7	41.9
		Nominal	Average Customer Bill ($)	1,602	1,614	1,610	1,633	1,667	1,632	1,657	1,696	1,744	1,795	1,920	2,150	2,378
		Real		1,602	1,567	1,518	1,495	1,481	1,408	1,388	1,379	1,377	1,376	1,347	1,380	1,356
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.5	-2.2	-2.6	-3.4	-5.1	-7.4	-10.2	-13.8	-18.0	-23.6	-44.4	-77.0	-132.8
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.6	-1.0	-1.5	-2.3	-3.3	-4.7	-6.5	-8.9	-19.2	-37.9	-79.7
			Energy Svc Charge ($M)	1.4	2.9	4.5	6.2	8.0	9.8	11.8	13.9	15.0	16.4	19.6	22.5	25.7
43,605	3.075	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,219	2,293	2,380	2,371	2,448	2,548	2,660	2,778	3,106	3,609	4,206
	0.07	Real		2,147	2,129	2,091	2,098	2,114	2,045	2,050	2,072	2,100	2,129	2,178	2,316	2,399
	2.45	Nominal	Cost in mills/kWh	47.4	47.4	51.7	52.1	52.7	51.2	51.6	52.5	53.9	55.5	58.4	63.8	69.4
	-0.53	Real		47.4	46.0	48.7	47.7	46.9	44.2	43.2	42.7	42.6	42.5	40.9	40.9	39.6

Notes:

1) $M = millions of dollars 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **43.14**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.29**

625 MW OWC Industrial Customer Load Loss in 1999

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,049	50,509	46,951	47,730	48,664	49,777	50,994	52,428	53,268	54,220	57,823	61,326	64,871
	MWa	5,713	5,766	5,360	5,449	5,555	5,682	5,821	5,985	6,081	6,189	6,601	7,001	7,405
	Total Annual Emissions (1000 Tons)													
0.48%	CO2	56,596	56,923	53,621	54,145	54,152	54,519	55,486	55,971	56,281	57,111	58,476	60,538	61,982
-0.02%	NOx	132.6	131.7	125.4	125.3	127.1	129.8	131.3	130.9	130.7	131.3	131.4	132.0	132.1
0.09%	TSP	11.8	11.7	11.4	11.4	11.4	11.6	11.7	11.7	11.7	11.8	11.8	11.9	12.0
	Annual System Emission Rates (Pounds/MWh)													
-0.88%	CO2	2,262	2,254	2,284	2,269	2,226	2,191	2,176	2,135	2,113	2,107	2,023	1,974	1,911
-1.37%	NOx	5.30	5.22	5.34	5.25	5.22	5.22	5.15	4.99	4.91	4.84	4.54	4.31	4.07
-1.27%	TSP	0.47	0.46	0.49	0.48	0.47	0.47	0.46	0.45	0.44	0.43	0.41	0.39	0.37
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.66	101.00	100.32	98.40	96.86	96.22	94.41	93.43	93.15	89.43	87.30	84.49
	NOx	100	98.43	100.83	99.10	98.55	98.44	97.19	94.22	92.64	91.38	85.77	81.26	76.89
	TSP	100	98.60	103.36	101.14	99.68	98.70	97.43	94.85	93.20	92.04	86.81	82.44	78.41

20 Year Emissions (1000 Tons)	Average	Total
CO2	57,709	1,154,178
NOx	131	2,614
TSP	12	235

625 MW OWC Industrial Customer
Load Loss in 1999
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch												230.7	401.0
	DSM Programs	6.8	7.1	7.0	7.3	7.3	7.3	7.8	7.8	7.8	11.5	20.2	24.4	30.5
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2								36.6		107.2	325.1	377.7	418.8
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.3**	**7.3**	**7.8**	**44.4**	**7.8**	**118.7**	**345.3**	**402.1**	**449.3**
	DSM Programs	0.6	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.9	1.5	1.7	2.1
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.9**	**1.5**	**1.7**	**2.1**
	DSM Programs	9.7	9.2	9.5	11.7	11.4	12.2	11.9	12.2	12.7	19.5	34.9	41.7	54.6
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**9.7**	**9.2**	**9.5**	**11.7**	**11.4**	**12.2**	**11.9**	**12.2**	**12.7**	**19.5**	**34.9**	**41.7**	**54.6**
	DSM Programs	2.5	2.5	2.7	2.8	2.9	3.0	2.9	3.0	3.1	4.6	7.3	8.2	10.3
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.5**	**2.5**	**2.7**	**2.8**	**2.9**	**3.0**	**2.9**	**3.0**	**3.1**	**4.6**	**7.3**	**8.2**	**10.3**
T	DSM Programs	19.6	19.3	19.7	22.4	22.1	23.1	23.2	23.6	24.2	36.5	63.9	76.0	97.5
O	Short Term Cap Purch												230.7	401.0
T	Cogeneration								36.6		107.2	325.1	377.7	418.8
A	Combined Cycle CT													
L	All Others													
	Total	**19.6**	**19.3**	**19.7**	**22.4**	**22.1**	**23.1**	**23.2**	**60.2**	**24.2**	**143.7**	**389.0**	**684.4**	**917.3**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,313	7,403	6,930	7,146	7,315	7,512	7,726	7,975	8,133	8,319	8,951	9,579	10,238
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	(20)	(39)	(59)	(81)	(103)	(126)	(149)	(173)	(197)	(234)	(298)	(374)	(471)
T	**Total Requirements**	**9,875**	**10,012**	**9,240**	**9,360**	**9,145**	**9,194**	**9,355**	**9,380**	**9,306**	**9,447**	**9,765**	**10,192**	**10,709**
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												231	401
&	New Resources								37	37	144	469	846	1,265
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,962**	**10,948**	**10,678**	**10,663**	**10,461**	**10,465**	**10,455**	**10,742**	**11,212**	**11,780**

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
Reserves	1,220	1,174	1,891	1,601	1,804	1,484	1,308	1,080	1,158	1,007	976	1,019	1,071
Reserve Margin (RM) (%	12.4	11.7	20.5	17.1	19.7	16.1	14.0	11.5	12.4	10.7	10.0	10.0	10.0

625 MW OWC Industrial Customer Load Loss in 1999

Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.2	10.5	15.9	21.6	27.2	32.9	39.1	45.3	51.6	60.8	76.9	96.1	120.5
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2								32.8	32.8	122.4	399.0	720.6	1,076.9
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.2**	**32.9**	**39.1**	**78.1**	**84.3**	**183.3**	**475.9**	**816.7**	**1,197.4**
	DSM Programs	0.4	0.9	1.3	1.7	2.1	2.6	3.1	3.5	4.0	4.7	5.9	7.2	8.9
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.1**	**2.6**	**3.1**	**3.5**	**4.0**	**4.7**	**5.9**	**7.2**	**8.9**
	DSM Programs	6.5	12.8	18.8	26.6	34.1	42.2	50.2	58.3	66.8	79.9	103.7	132.4	170.3
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**6.5**	**12.8**	**18.8**	**26.6**	**34.1**	**42.2**	**50.2**	**58.3**	**66.8**	**79.9**	**103.7**	**132.4**	**170.3**
	DSM Programs	2.0	4.0	6.2	8.5	10.8	13.2	15.6	18.0	20.4	24.0	30.0	36.8	45.5
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.0**	**4.0**	**6.2**	**8.5**	**10.8**	**13.2**	**15.6**	**18.0**	**20.4**	**24.0**	**30.0**	**36.8**	**45.5**
	DSM Programs	14.1	28.1	42.1	58.3	74.3	90.9	107.9	125.2	142.8	169.5	216.5	272.6	345.2
	Short Term Cap Purch												0.2	0.4
T	Cogeneration								32.8	32.8	122.4	399.0	720.6	1,076.9
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**14.1**	**28.1**	**42.1**	**58.3**	**74.3**	**90.9**	**107.9**	**157.9**	**175.6**	**291.9**	**615.5**	**993.4**	**1,422.6**
S	**Native Load**	5,417.0	5,484.0	5,095.1	5,248.1	5,370.0	5,513.0	5,668.0	5,848.1	5,963.1	6,098.1	6,555.9	7,012.0	7,489.2
Y	**Pump Storage/Peak Ret**	309.1	288.0	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	873.9	979.9	1,202.6	1,300.4	1,351.5	1,336.3	1,328.7	1,267.0	1,327.7	1,274.3	1,324.5	1,267.0	1,213.0
E	**DSM Programs**	(14.1)	(28.1)	(42.1)	(58.3)	(74.3)	(90.9)	(107.9)	(125.1)	(142.8)	(169.5)	(216.5)	(272.6)	(345.2)
M	**Total Requirements**	8,980.1	8,995.6	8,568.3	8,543.0	8,465.3	8,443.2	8,542.0	8,532.4	8,528.4	8,545.3	8,842.8	9,078.0	9,384.4
	Existing Generation	7,775.0	7,695.0	7,325.1	7,312.4	7,464.0	7,653.2	7,737.7	7,710.8	7,686.2	7,628.7	7,643.5	7,542.4	7,528.4
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	710.8	494.3	484.5	465.7	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	335.8	330.6	278.2	266.9	290.5	295.7	319.7	323.1	343.6	328.3	353.1	370.9	370.1
R	**New Resources**								32.8	32.8	122.4	399.0	720.8	1,077.3
	Total Resources	8,980.1	8,995.6	8,568.2	8,543.0	8,465.3	8,443.3	8,542.0	8,532.4	8,528.4	8,545.3	8,842.8	9,078.0	9,384.4

625 MW OWC Industrial Customer
Load Loss in 1999

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,404	5,557	5,678	5,821	5,977	6,157	6,272	6,407	6,864	7,320	7,798
			Conservation (MWa)	14	28	42	58	74	91	108	125	143	169	216	273	345
			After Conservation													
			System Load (MWa)	5,711	5,764	5,361	5,498	5,604	5,731	5,869	6,031	6,129	6,237	6,648	7,048	7,452
	0.51		Energy Sales (MWa)	5,160	5,259	4,860	4,971	5,084	5,200	5,318	5,428	5,502	5,558	5,875	6,210	6,602
			Total Customers (000's)	1,339	1,357	1,376	1,401	1,424	1,448	1,472	1,497	1,520	1,544	1,617	1,686	1,791
			Net Electric Plant ($M)	8,010	8,175	8,390	8,557	8,711	8,896	9,099	9,332	9,590	9,822	10,975	12,154	13,900
			Net Conservation Assets ($M)	15	29	43	58	70	83	94	106	118	133	165	190	220
			Utility Cost													
44,108	3.17	Nominal	**Operating Revenues ($M)**	2,146	2,191	2,220	2,292	2,377	2,367	2,443	2,539	2,656	2,775	3,094	3,612	4,249
	0.16	Real		2,146	2,127	2,092	2,098	2,112	2,042	2,046	2,065	2,097	2,127	2,170	2,319	2,423
	2.65	Nominal	Cost in mills/kWh	47.5	47.6	52.1	52.6	53.4	52.0	52.4	53.4	55.1	57.0	60.1	66.4	73.5
	-0.34	Real		47.5	46.2	49.1	48.2	47.4	44.8	43.9	43.4	43.5	43.7	42.2	42.6	41.9
		Nominal	Average Customer Bill ($)	1,602	1,614	1,614	1,636	1,669	1,635	1,659	1,697	1,747	1,797	1,913	2,143	2,373
		Real		1,602	1,567	1,521	1,497	1,483	1,411	1,390	1,380	1,379	1,378	1,342	1,375	1,353
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.5	-2.2	-2.6	-3.5	-5.1	-7.4	-10.2	-13.7	-17.9	-23.4	-44.1	-76.6	-132.0
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.6	-1.0	-1.5	-2.3	-3.3	-4.7	-6.5	-8.9	-19.1	-37.7	-79.2
			Energy Svc Charge ($M)	1.4	2.9	4.5	6.2	7.9	9.8	11.8	14.0	15.2	16.7	20.3	23.6	27.4
43,551	3.065	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,223	2,297	2,383	2,375	2,451	2,549	2,665	2,783	3,095	3,598	4,198
	0.06	Real		2,147	2,129	2,096	2,102	2,117	2,049	2,053	2,072	2,104	2,133	2,171	2,310	2,394
	2.44	Nominal	Cost in mills/kWh	47.4	47.4	51.8	52.2	52.8	51.3	51.7	52.5	54.0	55.6	58.2	63.6	69.3
	-0.54	Real		47.4	46.0	48.8	47.8	46.9	44.3	43.3	42.7	42.6	42.6	40.8	40.8	39.5

Notes:

1) $M = millions of dollars
2) General Inflation Rate is 3.0% annually
3) 50-year Real Levelized Utility Cost in mills/kWh = **43.15**
4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.24**

625 MW OWC Industrial Customer Load Loss in 1999

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,037	50,318	46,955	47,726	48,655	49,762	50,971	52,397	53,234	54,182	57,782	61,286	64,828
	MWa	5,712	5,744	5,360	5,448	5,554	5,681	5,819	5,981	6,077	6,185	6,596	6,996	7,400
	Total Annual Emissions (1000 Tons)													
0.45%	CO_2	56,594	56,926	53,038	53,781	53,932	54,334	55,367	55,783	56,017	56,820	58,232	60,293	61,669
-0.05%	NO_x	132.6	131.7	123.4	124.0	126.3	129.2	130.9	130.3	129.9	130.4	130.7	131.3	131.3
0.03%	TSP	11.8	11.7	11.1	11.1	11.3	11.5	11.6	11.6	11.6	11.6	11.7	11.8	11.9
	Annual System Emission Rates (Pounds/MWh)													
-0.91%	CO_2	2,262	2,263	2,259	2,254	2,217	2,184	2,172	2,129	2,105	2,097	2,016	1,968	1,903
-1.41%	NO_x	5.30	5.24	5.25	5.20	5.19	5.19	5.14	4.97	4.88	4.81	4.52	4.29	4.05
-1.32%	TSP	0.47	0.47	0.47	0.47	0.46	0.46	0.46	0.44	0.44	0.43	0.41	0.39	0.37
	Emission Rates as Percent of 1997 Base													
	CO_2	100	100.02	99.87	99.63	98.00	96.54	96.04	94.13	93.04	92.72	89.10	86.98	84.11
	NO_x	100	98.79	99.14	98.07	97.96	97.97	96.92	93.85	92.08	90.81	85.34	80.88	76.42
	TSP	100	98.97	100.31	98.81	98.55	97.92	96.82	94.07	92.36	91.13	86.21	81.94	77.69

20 Year Emissions (1000 Tons)	Average	Total
CO_2	57,465	1,149,305
NO_x	130	2,599
TSP	12	233

625 MW OWC Industrial Customer
125 MW / Year Load Loss Starting in 1999
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch											78.7	328.5	500.0
	DSM Programs	6.8	7.1	6.3	5.8	5.8	5.9	5.9	5.9	5.8	8.7	15.2	18.0	22.3
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2										79.6	309.3	358.3	360.2
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**6.3**	**5.8**	**5.8**	**5.9**	**5.9**	**5.9**	**5.8**	**88.3**	**324.5**	**376.3**	**382.5**
	DSM Programs	0.6	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.9	1.5	1.7	2.1
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.9**	**1.5**	**1.7**	**2.1**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	12.9	13.0	14.2	22.2	38.7	46.9	60.9
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													58.1
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													18.0
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**12.9**	**13.0**	**14.2**	**22.2**	**38.7**	**46.9**	**137.0**
	DSM Programs	2.7	2.6	2.8	2.9	2.9	2.9	3.0	3.1	3.0	4.6	8.1	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.7**	**2.6**	**2.8**	**2.9**	**2.9**	**2.9**	**3.0**	**3.1**	**3.0**	**4.6**	**8.1**	**9.5**	**11.9**
T	DSM Programs	21.6	21.4	21.5	21.9	21.5	22.4	22.4	22.6	23.6	36.4	63.5	76.1	97.2
O	Short Term Cap Purch											78.7	328.5	500.0
T	Cogeneration										79.6	309.3	358.3	418.3
A	Combined Cycle CT													
L	All Others													18.0
	Total	**21.6**	**21.4**	**21.5**	**21.9**	**21.5**	**22.4**	**22.4**	**22.6**	**23.6**	**116.0**	**451.5**	**762.9**	**1,033.5**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,313	7,403	7,430	7,521	7,565	7,637	7,726	7,975	8,133	8,319	8,951	9,579	10,238
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)	(64)	(86)	(108)	(130)	(153)	(175)	(199)	(235)	(299)	(375)	(472)
T	**Total Requirements**	**9,873**	**10,008**	**9,735**	**9,730**	**9,390**	**9,315**	**9,351**	**9,378**	**9,304**	**9,446**	**9,764**	**10,191**	**10,708**
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	9,509
	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											79	329	500
&	New Resources										80	389	748	1,183
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,962**	**10,948**	**10,678**	**10,663**	**10,424**	**10,428**	**10,391**	**10,741**	**11,212**	**11,779**

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
Reserves	1,223	1,178	1,397	1,232	1,558	1,364	1,311	1,046	1,124	945	976	1,019	1,071
Reserve Margin (RM) (%	12.4	11.8	14.3	12.7	16.6	14.6	14.0	11.2	12.1	10.0	10.0	10.0	10.0

625 MW OWC Industrial Customer
125 MW / Year Load Loss Starting in 1999
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.2	10.5	15.2	19.3	23.5	27.9	32.3	36.6	41.0	47.5	58.7	72.1	88.7
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2										67.7	331.0	636.0	942.4
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.2**	**19.3**	**23.5**	**27.9**	**32.3**	**36.6**	**41.0**	**115.2**	**389.7**	**708.0**	**1,031.1**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	0.4	0.9	1.3	1.7	2.2	2.6	3.1	3.5	4.0	4.7	5.9	7.3	8.9
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.2**	**2.6**	**3.1**	**3.5**	**4.0**	**4.7**	**5.9**	**7.3**	**8.9**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	67.4	77.4	92.9	120.3	153.7	197.4
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													49.4
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													16.9
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**67.4**	**77.4**	**92.9**	**120.3**	**153.7**	**263.7**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	2.2	4.3	6.6	8.9	11.3	13.6	16.0	18.4	20.9	24.5	31.3	39.3	49.6
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.3**	**6.6**	**8.9**	**11.3**	**13.6**	**16.0**	**18.4**	**20.9**	**24.5**	**31.3**	**39.3**	**49.6**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	15.6	31.1	46.6	62.2	77.5	93.6	109.7	126.0	143.2	169.6	216.2	272.3	344.6
	Short Term Cap Purch											0.1	0.3	0.5
T	Cogeneration										67.7	331.0	636.0	991.9
O	Combined Cycle CT													
T	Coal													
A	Transmission													16.9
L	Simple Cycle													
	Storage													
	Total	**15.6**	**31.1**	**46.6**	**62.2**	**77.5**	**93.6**	**109.7**	**126.0**	**143.2**	**237.3**	**547.2**	**908.6**	**1,353.9**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	**Native Load**	5,417.0	5,484.0	5,495.1	5,548.1	5,570.0	5,613.0	5,668.0	5,848.1	5,963.1	6,098.1	6,555.9	7,012.0	7,489.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.3	983.9	1,141.6	1,277.1	1,336.1	1,368.2	1,368.7	1,286.4	1,348.2	1,296.8	1,317.8	1,227.2	1,191.6
E	**DSM Programs**	(15.6)	(31.1)	(46.6)	(62.1)	(77.5)	(93.6)	(109.7)	(126.0)	(143.2)	(169.6)	(216.2)	(272.4)	(344.6)
M	**Total Requirements**	8,986.9	9,018.0	8,902.8	8,815.9	8,646.7	8,572.5	8,580.2	8,551.0	8,548.4	8,567.7	8,836.3	9,038.4	9,363.7
	Existing Generation	7,774.1	7,713.9	7,620.7	7,529.4	7,611.2	7,725.8	7,755.0	7,734.9	7,729.3	7,674.2	7,683.1	7,574.3	7,553.5
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	711.3	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.5	334.1	317.1	322.8	324.1	350.6	339.6	350.2	353.3	359.8	375.1	383.9	392.3
R	**New Resources**										67.7	331.1	636.3	1,009.3
	Total Resources	8,986.9	9,018.0	8,902.8	8,815.9	8,646.7	8,572.5	8,580.2	8,551.0	8,548.4	8,567.6	8,836.3	9,038.4	9,363.7

625 MW OWC Industrial Customer
125 MW / Year Load Loss Starting in 1999

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,022	50,478	50,420	50,321	50,379	50,614	50,955	52,390	53,230	54,180	57,784	61,288	64,833
	MWa	5,710	5,762	5,756	5,744	5,751	5,778	5,817	5,981	6,076	6,185	6,596	6,996	7,401
	Total Annual Emissions (1000 Tons)													
0.48%	CO2	56,585	56,900	56,304	56,198	55,556	55,135	55,459	55,950	56,252	57,096	58,458	60,520	61,965
-0.02%	NOx	132.6	131.7	129.5	128.6	129.4	130.7	131.3	130.8	130.7	131.3	131.4	132.0	132.1
0.09%	TSP	11.8	11.7	11.6	11.6	11.6	11.6	11.7	11.7	11.7	11.8	11.8	11.9	12.0
	Annual System Emission Rates (Pounds/MWh)													
-0.88%	CO2	2,262	2,254	2,233	2,234	2,206	2,179	2,177	2,136	2,114	2,108	2,023	1,975	1,912
-1.37%	NOx	5.30	5.22	5.14	5.11	5.14	5.16	5.15	5.00	4.91	4.85	4.55	4.31	4.08
-1.27%	TSP	0.47	0.47	0.46	0.46	0.46	0.46	0.46	0.45	0.44	0.43	0.41	0.39	0.37
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.72	98.73	97.49	96.30	96.22	94.41	93.42	93.16	89.43	87.29	84.49
	NOx	100	98.42	96.95	96.41	96.90	97.44	97.19	94.24	92.64	91.41	85.79	81.27	76.90
	TSP	100	98.59	97.87	97.76	97.59	97.50	97.44	94.87	93.24	92.06	86.82	82.44	78.42

20 Year Emissions (1000 Tons)	Average	Total
CO2	58,032	1,160,636
NOx	131	2,624
TSP	12	236

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625 MW OWC Industrial Customer
125 MW / Year Load Loss Starting in 1999

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,804	5,857	5,878	5,921	5,977	6,157	6,272	6,407	6,864	7,320	7,798
			Conservation (MWa)	16	31	47	62	77	94	110	126	143	170	216	272	345
			After Conservation													
			System Load (MWa)	5,710	5,761	5,757	5,794	5,801	5,828	5,867	6,031	6,128	6,237	6,648	7,048	7,453
	0.51		Energy Sales (MWa)	5,159	5,257	5,256	5,267	5,281	5,298	5,316	5,427	5,501	5,558	5,875	6,210	6,603
			Total Customers (000's)	1,339	1,357	1,379	1,403	1,426	1,449	1,472	1,497	1,520	1,544	1,617	1,686	1,791
			Net Electric Plant ($M)	8,012	8,178	8,394	8,562	8,715	8,885	9,068	9,290	9,534	9,766	10,905	12,068	13,840
			Net Conservation Assets ($M)	16	32	47	62	75	88	99	110	121	135	165	189	218
			Utility Cost													
44,269	3.18	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,269	2,328	2,404	2,381	2,439	2,538	2,651	2,770	3,104	3,623	4,258
	0.17	Real		2,146	2,126	2,139	2,130	2,136	2,054	2,042	2,064	2,093	2,123	2,177	2,325	2,428
	2.66	Nominal	Cost in mills/kWh	47.5	47.6	49.3	50.5	52.0	51.3	52.4	53.4	55.0	56.9	60.3	66.6	73.6
	-0.33	Real		47.5	46.2	46.5	46.2	46.2	44.3	43.9	43.4	43.4	43.6	42.3	42.7	42.0
		Nominal	Average Customer Bill ($)	1,602	1,614	1,646	1,659	1,686	1,644	1,656	1,696	1,744	1,794	1,919	2,149	2,377
		Real		1,602	1,567	1,551	1,518	1,498	1,418	1,387	1,379	1,376	1,375	1,346	1,379	1,356
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.3	-2.7	-3.4	-5.0	-7.2	-9.9	-13.4	-17.4	-22.8	-43.3	-75.4	-130.7
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.5	-2.3	-3.3	-4.6	-6.4	-8.7	-18.7	-37.0	-78.0
			Energy Svc Charge ($M)	1.6	3.2	5.0	6.8	8.7	10.7	12.7	15.0	16.0	17.4	20.7	23.9	27.4
43,723	3.074	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,273	2,334	2,411	2,390	2,448	2,548	2,661	2,779	3,106	3,610	4,208
	0.07	Real		2,147	2,129	2,143	2,136	2,142	2,061	2,050	2,072	2,100	2,130	2,178	2,317	2,400
	2.45	Nominal	Cost in mills/kWh	47.4	47.4	49.0	50.0	51.4	50.7	51.6	52.5	53.9	55.5	58.4	63.8	69.4
	-0.53	Real		47.4	46.0	46.2	45.8	45.7	43.7	43.2	42.7	42.6	42.6	40.9	40.9	39.6

Notes:

1) $M = millions of dollars
2) General Inflation Rate is 3.0% annually
3) 50-year Real Levelized Utility Cost in mills/kWh = 43.00
4) 50-year Real Levelized Total Resource Cost in mills/kWh = 41.11

625 MW OWC Industrial Customer
125 MW / Year Load Loss Starting in 1999
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch												236.7	402.3
	DSM Programs	6.8	7.1	7.0	7.3	7.3	7.3	7.8	7.8	7.8	11.5	20.2	24.4	30.5
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2								39.9		116.6	324.1	375.5	429.5
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.3**	**7.3**	**7.8**	**47.7**	**7.8**	**128.1**	**344.3**	**399.9**	**460.0**
	DSM Programs	0.6	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.9	1.5	1.7	2.1
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.9**	**1.5**	**1.7**	**2.1**
	DSM Programs	9.7	9.2	10.3	11.2	10.4	10.7	10.5	10.7	11.0	18.1	32.5	38.3	49.0
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**9.7**	**9.2**	**10.3**	**11.2**	**10.4**	**10.7**	**10.5**	**10.7**	**11.0**	**18.1**	**32.5**	**38.3**	**49.0**
	DSM Programs	2.5	2.5	2.7	2.8	2.9	3.0	2.9	3.0	3.1	4.6	7.3	8.2	10.3
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.5**	**2.5**	**2.7**	**2.8**	**2.9**	**3.0**	**2.9**	**3.0**	**3.1**	**4.6**	**7.3**	**8.2**	**10.3**
T	DSM Programs	19.6	19.3	20.5	21.9	21.1	21.6	21.8	22.1	22.5	35.1	61.5	72.6	91.9
O	Short Term Cap Purch												236.7	402.3
T	Cogeneration								39.9		116.6	324.1	375.5	429.5
A	Combined Cycle CT													
L	All Others													
	Total	**19.6**	**19.3**	**20.5**	**21.9**	**21.1**	**21.6**	**21.8**	**62.0**	**22.5**	**151.7**	**385.6**	**684.8**	**923.7**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	Native Load	7,313	7,403	7,430	7,521	7,565	7,637	7,726	7,975	8,133	8,319	8,951	9,579	10,238
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	(20)	(39)	(59)	(81)	(102)	(124)	(146)	(168)	(190)	(225)	(287)	(360)	(452)
T	**Total Requirements**	9,875	10,012	9,740	9,735	9,396	9,321	9,358	9,385	9,313	9,456	9,776	10,206	10,728
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												237	402
&	New Resources								40	40	156	481	856	1,286
R	**Total Resources**	11,096	11,185	11,131	10,962	10,948	10,678	10,663	10,464	10,468	10,467	10,754	11,228	11,802
	Reserves	1,220	1,174	1,392	1,227	1,553	1,357	1,304	1,078	1,155	1,012	977	1,021	1,073
	Reserve Margin (RM) (%	12.4	11.7	14.3	12.6	16.5	14.6	13.9	11.5	12.4	10.7	10.0	10.0	10.0

625 MW OWC Industrial Customer
125 MW / Year Load Loss Starting in 1999
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.2	10.5	15.9	21.6	27.2	32.9	39.1	45.3	51.6	60.8	76.9	96.1	120.5
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2								35.7	35.7	133.2	409.0	728.6	1,094.1
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.2**	**32.9**	**39.1**	**81.0**	**87.3**	**194.0**	**485.9**	**824.7**	**1,214.6**
	DSM Programs	0.4	0.9	1.3	1.7	2.2	2.6	3.1	3.5	4.0	4.7	5.9	7.3	8.9
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.2**	**2.6**	**3.1**	**3.5**	**4.0**	**4.7**	**5.9**	**7.3**	**8.9**
	DSM Programs	6.5	12.8	19.6	26.8	33.4	40.1	46.7	53.3	60.1	71.8	93.2	118.5	150.9
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**6.5**	**12.8**	**19.6**	**26.8**	**33.4**	**40.1**	**46.7**	**53.3**	**60.1**	**71.8**	**93.2**	**118.5**	**150.9**
	DSM Programs	2.0	4.0	6.2	8.5	10.8	13.2	15.6	18.0	20.4	24.0	30.0	36.8	45.5
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.0**	**4.0**	**6.2**	**8.5**	**10.8**	**13.2**	**15.6**	**18.0**	**20.4**	**24.0**	**30.0**	**36.8**	**45.5**
	DSM Programs	14.1	28.1	43.0	58.6	73.6	88.8	104.4	120.1	136.1	161.3	205.9	258.8	325.9
	Short Term Cap Purch												0.2	0.4
T	Cogeneration								35.7	35.7	133.2	409.0	728.6	1,094.1
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**14.1**	**28.1**	**43.0**	**58.6**	**73.6**	**88.8**	**104.4**	**155.8**	**171.8**	**294.5**	**615.0**	**987.6**	**1,420.4**
S	**Native Load**	5,417.0	5,484.0	5,495.1	5,548.1	5,570.0	5,613.0	5,668.0	5,848.1	5,963.1	6,098.1	6,555.9	7,012.0	7,489.2
Y	**Pump Storage/Peak Ret**	309.4	309.5	299.0	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	878.4	979.9	1,127.9	1,215.9	1,316.1	1,297.3	1,328.1	1,266.9	1,310.0	1,282.5	1,325.2	1,265.9	1,211.9
E	**DSM Programs**	(14.1)	(28.1)	(43.0)	(58.6)	(73.6)	(88.8)	(104.4)	(120.1)	(136.1)	(161.3)	(205.9)	(258.7)	(325.9)
M	**Total Requirements**	8,984.9	9,017.1	8,884.5	8,758.3	8,630.6	8,506.3	8,545.0	8,537.3	8,517.4	8,561.7	8,854.0	9,090.7	9,402.7
	Existing Generation	7,775.2	7,716.5	7,603.7	7,508.5	7,612.3	7,707.8	7,740.0	7,712.8	7,688.7	7,628.5	7,644.7	7,546.5	7,529.5
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	710.8	494.8	484.5	465.7	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	340.4	330.6	315.8	286.0	307.5	303.7	320.4	323.1	327.1	334.2	353.1	371.5	370.0
R	**New Resources**								35.7	35.7	133.2	409.0	728.8	1,094.5
	Total Resources	8,984.9	9,017.1	8,884.5	8,758.3	8,630.6	8,506.3	8,545.0	8,537.3	8,517.4	8,561.7	8,854.0	9,090.7	9,402.6

625 MW OWC Industrial Customer
125 MW / Year Load Loss Starting in 1999

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,804	5,857	5,878	5,921	5,977	6,157	6,272	6,407	6,864	7,320	7,798
			Conservation (MWa)	14	28	43	59	74	89	104	120	136	161	206	259	326
			After Conservation													
			System Load (MWa)	5,711	5,764	5,761	5,798	5,805	5,833	5,872	6,036	6,136	6,245	6,658	7,062	7,472
	0.51		Energy Sales (MWa)	5,160	5,259	5,259	5,270	5,284	5,302	5,321	5,433	5,508	5,566	5,884	6,223	6,621
			Total Customers (000's)	1,339	1,357	1,379	1,403	1,426	1,449	1,472	1,497	1,520	1,544	1,617	1,686	1,791
			Net Electric Plant ($M)	8,010	8,175	8,390	8,557	8,712	8,897	9,101	9,336	9,599	9,828	10,975	12,147	13,902
			Net Conservation Assets ($M)	15	29	43	58	71	83	94	105	116	130	158	181	208
			Utility Cost													
44,256	3.17	Nominal	**Operating Revenues ($M)**	2,146	2,191	2,270	2,330	2,405	2,385	2,443	2,540	2,657	2,777	3,097	3,617	4,253
	0.17	Real		2,146	2,127	2,139	2,132	2,137	2,057	2,046	2,065	2,098	2,128	2,172	2,322	2,426
	2.65	Nominal	Cost in mills/kWh	47.5	47.6	49.3	50.5	52.0	51.3	52.4	53.4	55.1	57.0	60.1	66.4	73.3
	-0.34	Real		47.5	46.2	46.4	46.2	46.2	44.3	43.9	43.4	43.5	43.6	42.1	42.6	41.8
		Nominal	Average Customer Bill ($)	1,602	1,614	1,646	1,660	1,687	1,646	1,660	1,697	1,748	1,798	1,915	2,145	2,375
		Real		1,602	1,567	1,551	1,519	1,499	1,420	1,390	1,380	1,380	1,378	1,343	1,377	1,354
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.5	-2.2	-2.6	-3.4	-5.1	-7.4	-10.2	-13.8	-18.0	-23.6	-44.4	-77.0	-132.8
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.6	-1.0	-1.5	-2.3	-3.3	-4.7	-6.5	-8.9	-19.2	-37.9	-79.7
			Energy Svc Charge ($M)	1.4	2.9	4.5	6.2	8.0	9.8	11.8	13.9	15.0	16.4	19.6	22.5	25.7
43,689	3.069	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,273	2,335	2,411	2,392	2,452	2,549	2,666	2,784	3,097	3,601	4,199
	0.07	Real		2,147	2,129	2,143	2,137	2,142	2,064	2,053	2,073	2,105	2,134	2,172	2,312	2,395
	2.44	Nominal	Cost in mills/kWh	47.4	47.4	49.0	50.1	51.4	50.7	51.7	52.5	54.0	55.6	58.2	63.6	69.3
	-0.54	Real		47.4	46.0	46.2	45.8	45.7	43.8	43.3	42.7	42.7	42.6	40.8	40.8	39.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.90**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.08**

625 MW OWC Industrial Customer
125 MW / Year Load Loss Starting in 1999

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,039	50,506	50,380	50,353	50,413	50,656	51,002	52,441	53,292	54,253	57,874	61,406	64,997
	MWa	5,712	5,766	5,751	5,748	5,755	5,783	5,822	5,986	6,084	6,193	6,607	7,010	7,420
	Total Annual Emissions (1000 Tons)													
0.46%	CO2	56,594	56,926	56,266	56,089	55,577	55,051	55,394	55,814	56,056	56,856	58,276	60,368	61,744
-0.05%	NOx	132.6	131.7	129.4	128.2	129.4	130.3	131.0	130.4	129.9	130.4	130.7	131.4	131.3
0.04%	TSP	11.8	11.7	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.7	11.7	11.9	11.9
	Annual System Emission Rates (Pounds/MWh)													
-0.91%	CO2	2,262	2,254	2,234	2,228	2,205	2,174	2,172	2,129	2,104	2,096	2,014	1,966	1,900
-1.42%	NOx	5.30	5.22	5.14	5.09	5.13	5.15	5.14	4.97	4.88	4.81	4.52	4.28	4.04
-1.33%	TSP	0.47	0.47	0.46	0.46	0.46	0.46	0.46	0.44	0.44	0.43	0.41	0.39	0.37
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.66	98.75	98.49	97.47	96.09	96.03	94.10	93.00	92.66	89.03	86.92	83.99
	NOx	100	98.43	96.91	96.06	96.87	97.11	96.90	93.81	92.02	90.71	85.23	80.78	76.25
	TSP	100	98.60	97.78	97.31	97.44	96.93	96.78	94.03	92.31	91.11	86.10	81.89	77.51

20 Year Emissions (1000 Tons)	Average	Total
CO2	57,898	1,157,952
NOx	131	2,614
TSP	12	234

Flat Wholesale Short Term Market Prices
(Prices Constant at 1997 Levels)
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.0		110.2	301.1	500.0	412.2	500.0	500.0	500.0	500.0
	DSM Programs	6.8	7.1	7.0	7.5	7.9	7.9	8.0	8.0	8.0	12.3	20.5	24.3	30.7
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2								66.0		179.6	381.2	108.3	571.5
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT												492.2	7.8
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.5**	**7.9**	**7.9**	**8.0**	**74.0**	**8.0**	**191.9**	**401.7**	**624.8**	**610.0**
	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
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	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	12.7	12.4	13.0	13.1	13.8	14.4	22.8	39.3	47.3	61.4
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.7**	**12.4**	**13.0**	**13.1**	**13.8**	**14.4**	**22.8**	**39.3**	**47.3**	**61.4**
	DSM Programs	2.8	2.8	2.8	2.8	2.9	3.0	3.0	3.0	3.1	5.1	8.4	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**2.9**	**3.0**	**3.0**	**3.0**	**3.1**	**5.1**	**8.4**	**9.5**	**11.9**
T	DSM Programs	21.7	21.6	22.3	23.5	23.8	24.5	24.7	25.4	26.1	41.2	69.9	83.0	106.4
O	Short Term Cap Purch				13.0		110.2	301.1	500.0	412.2	500.0	500.0	500.0	500.0
T	Cogeneration								66.0		179.6	381.2	108.3	571.5
A	Combined Cycle CT													
L	All Others												492.2	7.8
	Total	**21.7**	**21.6**	**22.3**	**36.5**	**23.8**	**134.7**	**325.8**	**591.4**	**438.3**	**720.8**	**951.1**	**1,183.5**	**1,185.7**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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)	(113)	(137)	(162)	(188)	(214)	(255)	(325)	(408)	(514)
T	**Total Requirements**	**9,873**	**10,008**	**9,858**	**9,977**	**9,760**	**9,808**	**9,967**	**9,990**	**9,914**	**10,051**	**10,363**	**10,783**	**11,291**
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		110	301	500	412	500	500	500	500
&	New Resources								66	66	246	627	1,227	1,807
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**10,788**	**10,964**	**10,990**	**10,906**	**11,057**	**11,400**	**11,862**	**12,421**
	Reserves	1,223	1,178	1,273	998	1,188	981	997	999	991	1,005	1,036	1,078	1,129
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Flat Wholesale Short Term Market Prices
(Prices Constant at 1997 Levels)
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.2	10.5	15.9	21.5	27.5	33.5	39.5	45.6	51.7	61.1	77.0	96.1	120.6
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2								59.1	59.1	219.9	561.2	658.2	1,169.9
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT												19.6	19.9
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.5**	**27.5**	**33.5**	**39.5**	**104.8**	**110.9**	**281.0**	**638.2**	**773.9**	**1,310.4**
	DSM Programs	0.5	0.9	1.3	1.8	2.2	2.7	3.1	3.6	4.0	4.9	6.2	7.8	9.7
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.2**	**2.7**	**3.1**	**3.6**	**4.0**	**4.9**	**6.2**	**7.8**	**9.7**
	DSM Programs	7.8	15.4	23.5	32.2	40.7	49.6	58.6	68.2	78.3	94.2	121.8	155.4	199.1
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.7**	**49.6**	**58.6**	**68.2**	**78.3**	**94.2**	**121.8**	**155.4**	**199.1**
	DSM Programs	2.2	4.5	6.8	9.1	11.4	13.8	16.2	18.6	21.0	25.3	32.2	40.3	50.7
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.4**	**13.8**	**16.2**	**18.6**	**21.0**	**25.3**	**32.2**	**40.3**	**50.7**
	DSM Programs	15.7	31.3	47.5	64.5	81.7	99.5	117.4	136.0	155.1	185.4	237.3	299.6	380.1
	Short Term Cap Purch				0.0		0.1	0.2	0.4	0.2	0.3	0.3	0.3	
T	Cogeneration								59.1	59.1	219.9	561.2	658.2	1,169.9
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle												19.6	19.9
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**64.5**	**81.7**	**99.6**	**117.6**	**195.5**	**214.4**	**405.6**	**798.7**	**977.6**	**1,569.9**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	309.4	308.8	294.9	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	874.7	1,003.7	1,134.8	1,160.5	1,125.1	1,022.0	933.8	898.8	958.1	981.1	1,080.7	860.6	977.0
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(64.5)	(81.7)	(99.5)	(117.4)	(136.0)	(155.1)	(185.4)	(237.3)	(299.6)	(380.1)
M	**Total Requirements**	8,979.7	9,037.0	8,982.8	8,896.9	8,731.5	8,620.4	8,637.7	8,653.3	8,646.5	8,736.2	9,078.1	9,144.5	9,613.5
	Existing Generation	7,774.5	7,775.1	7,727.3	7,655.6	7,723.4	7,826.5	7,862.4	7,834.7	7,829.8	7,748.2	7,766.5	7,713.7	7,700.6
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	710.8	492.9	482.4	462.7	462.7	462.7	443.9	441.4	407.3
&	**Short Term Purchases**	335.8	291.9	290.5	277.6	297.2	301.0	292.6	296.4	294.6	305.1	306.3	311.5	315.8
R	**New Resources**						0.1	0.2	59.5	59.3	220.1	561.4	678.0	1,189.8
	Total Resources	8,979.7	9,037.0	8,982.8	8,896.9	8,731.5	8,620.4	8,637.7	8,653.3	8,646.4	8,736.1	9,078.1	9,144.5	9,613.5

Flat Wholesale Short Term Market Prices
(Prices Constant at 1997 Levels)

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	31	48	65	82	100	118	136	156	186	238	300	381
			After Conservation													
			System Load (MWa)	5,710	5,761	5,856	5,992	6,097	6,222	6,359	6,520	6,616	6,721	7,127	7,520	7,917
	0.65		Energy Sales (MWa)	5,159	5,256	5,355	5,465	5,577	5,692	5,809	5,918	5,990	6,043	6,355	6,684	7,069
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,178	8,396	8,562	8,727	8,930	9,153	9,399	9,703	9,929	11,131	12,261	14,189
			Net Conservation Assets ($M)	16	32	48	63	77	90	102	115	128	144	179	208	241
			Utility Cost													
47,528	3.34	Nominal	**Operating Revenues ($M)**	2,146	2,189	2,282	2,364	2,494	2,565	2,693	2,816	2,925	3,066	3,419	3,942	4,595
	0.33	Real		2,146	2,126	2,151	2,163	2,216	2,213	2,255	2,289	2,309	2,350	2,398	2,530	2,620
	2.68	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.4	51.1	51.4	52.9	54.3	55.8	57.9	61.4	67.3	74.2
	-0.31	Real		47.5	46.2	45.9	45.2	45.4	44.4	44.3	44.2	44.0	44.4	43.1	43.2	42.3
		Nominal	Average Customer Bill ($)	1,602	1,613	1,654	1,682	1,746	1,767	1,824	1,876	1,919	1,981	2,109	2,332	2,559
		Real		1,602	1,566	1,559	1,540	1,551	1,524	1,528	1,526	1,515	1,518	1,479	1,497	1,460
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.1	-43.7	-75.9	-131.1
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-19.0	-37.4	-78.6
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.2	26.2	30.7
46,996	3.245	Nominal	**Total Resource Cost ($M)**	2,147	2,192	2,287	2,370	2,501	2,574	2,702	2,827	2,935	3,075	3,423	3,931	4,547
	0.24	Real		2,147	2,128	2,155	2,168	2,222	2,220	2,263	2,298	2,317	2,357	2,401	2,523	2,593
	2.47	Nominal	Cost in mills/kWh	47.4	47.3	48.3	49.0	50.5	50.8	52.1	53.4	54.6	56.5	59.4	64.5	70.0
	-0.51	Real		47.4	46.0	45.6	44.8	44.9	43.8	43.7	43.4	43.1	43.3	41.7	41.4	39.9

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **43.34**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **41.44**

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Flat Wholesale Short Term Market Prices
(Prices Constant at 1997 Levels)

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,026	50,471	51,180	52,052	52,970	54,067	55,269	56,682	57,505	58,422	61,979	65,429	68,902
	MWa	5,711	5,762	5,843	5,942	6,047	6,172	6,309	6,471	6,565	6,669	7,075	7,469	7,866
	Total Annual Emissions (1000 Tons)													
0.69%	CO2	56,584	57,261	57,385	57,703	57,355	57,264	58,010	58,438	58,764	59,394	60,773	63,275	64,539
0.10%	NOx	132.6	132.9	132.0	131.2	131.8	133.0	133.7	133.2	133.1	133.1	133.4	135.4	135.2
0.12%	TSP	11.8	11.8	11.8	11.8	11.7	11.8	11.8	11.8	11.9	11.9	12.0	12.0	12.1
	Annual System Emission Rates (Pounds/MWh)													
-0.99%	CO2	2,262	2,269	2,242	2,217	2,166	2,118	2,099	2,062	2,044	2,033	1,961	1,934	1,873
-1.57%	NOx	5.30	5.27	5.16	5.04	4.98	4.92	4.84	4.70	4.63	4.56	4.31	4.14	3.92
-1.55%	TSP	0.47	0.47	0.46	0.45	0.44	0.44	0.43	0.42	0.41	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	100.30	99.13	98.01	95.73	93.64	92.79	91.15	90.34	89.88	86.69	85.50	82.81
	NOx	100	99.38	97.32	95.13	93.89	92.79	91.28	88.65	87.34	85.98	81.24	78.06	74.04
	TSP	100	99.28	97.70	95.90	94.03	92.48	90.88	88.56	87.41	86.18	81.78	77.98	74.31

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,134	1,202,679
NOx	134	2,672
TSP	12	238

10 Percent more Transmission Capacity East to West

Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.3				72.2		119.3	232.9	476.5	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
	OWC Geothermal													
O	OWC Cogen 1													115.9
W	OWC Cogen 2						186.8	200.8	107.5		132.2	267.5	356.9	54.9
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**194.5**	**208.6**	**115.6**	**8.0**	**144.7**	**288.1**	**381.3**	**201.4**
	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
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	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													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													385.0
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	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**	**446.4**
	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 IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	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				72.2		119.3	232.9	476.5	500.0
T	Cogeneration						186.8	200.8	107.5		132.2	267.5	356.9	555.8
A	Combined Cycle CT													
L	All Others													
	Total	**21.7**	**21.6**	**22.3**	**36.5**	**23.6**	**211.1**	**225.1**	**205.2**	**26.0**	**292.9**	**570.4**	**916.4**	**1,162.2**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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				72		119	233	477	500
&	New Resources						187	388	495	495	628	895	1,252	1,808
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**10,865**	**11,051**	**10,991**	**10,923**	**11,058**	**11,401**	**11,864**	**12,422**
	Reserves	1,223	1,178	1,273	998	1,188	1,057	1,082	999	1,007	1,005	1,036	1,078	1,129
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.8	10.9	10.0	10.2	10.0	10.0	10.0	10.0

10 Percent more Transmission Capacity
East to West
Cumulative Annual Energy (MWa)

		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													114.8
W	OWC Cogen 2						181.7	347.0	443.3	443.3	533.9	761.5	1,065.3	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**215.4**	**386.9**	**489.5**	**495.8**	**596.2**	**840.1**	**1,163.2**	**1,349.2**
	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
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	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													327.7
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	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**	**526.5**
	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 IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	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**
	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
	Short Term Cap Purch				0.0				0.1		0.1	0.2	0.5	0.5
T	Cogeneration						181.7	347.0	443.3	443.3	533.9	761.5	1,065.3	1,554.5
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**281.4**	**464.6**	**579.8**	**599.1**	**720.5**	**1,000.5**	**1,367.0**	**1,936.7**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	884.6	991.6	1,113.1	1,172.0	1,191.6	1,242.4	1,292.6	1,277.6	1,339.3	1,293.1	1,298.6	1,210.3	1,225.3
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(64.6)	(81.8)	(99.7)	(117.6)	(136.4)	(155.8)	(186.5)	(238.7)	(301.3)	(381.7)
M	**Total Requirements**	8,989.1	9,025.4	8,973.4	8,908.4	8,797.8	8,840.6	8,996.2	9,031.6	9,027.0	9,047.1	9,294.6	9,492.5	9,860.3
	Existing Generation	7,780.7	7,727.9	7,679.5	7,614.8	7,751.0	7,805.1	7,816.2	7,769.8	7,766.4	7,690.2	7,709.3	7,598.3	7,517.3
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	339.0	327.6	328.9	329.8	334.1	357.7	347.4	352.6	351.5	357.0	376.5	384.6	379.4
R	**New Resources**						181.7	347.0	443.3	443.3	534.0	761.7	1,065.7	1,555.0
	Total Resources	8,989.1	9,025.4	8,973.4	8,908.3	8,797.8	8,840.6	8,996.2	9,031.6	9,027.0	9,047.1	9,294.6	9,492.5	9,860.3

10 Percent more Transmission Capacity East to West

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	31	48	65	82	100	118	136	156	187	239	301	382
			After Conservation													
			System Load (MWa)	5,710	5,761	5,856	5,992	6,097	6,222	6,359	6,520	6,616	6,720	7,126	7,519	7,916
	0.65		Energy Sales (MWa)	5,159	5,256	5,355	5,465	5,577	5,692	5,809	5,918	5,990	6,043	6,354	6,683	7,069
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,178	8,403	8,644	8,961	9,263	9,499	9,726	9,997	10,206	11,276	12,412	14,485
			Net Conservation Assets ($M)	16	32	48	63	77	90	102	115	128	144	185	219	259
			Utility Cost													
45,825	3.24	Nominal	**Operating Revenues ($M)**	2,145	2,190	2,282	2,358	2,450	2,452	2,549	2,683	2,797	2,939	3,279	3,792	4,399
	0.23	Real		2,145	2,126	2,151	2,158	2,177	2,115	2,134	2,181	2,208	2,252	2,300	2,434	2,509
	2.57	Nominal	Cost in mills/kWh	47.5	47.6	48.6	49.3	50.2	49.2	50.1	51.8	53.3	55.5	58.9	64.8	71.0
	-0.42	Real		47.5	46.2	45.9	45.1	44.6	42.4	42.0	42.1	42.1	42.6	41.3	41.6	40.5
		Nominal	Average Customer Bill ($)	1,601	1,614	1,654	1,678	1,715	1,689	1,726	1,788	1,835	1,899	2,022	2,244	2,450
		Real		1,601	1,567	1,559	1,536	1,524	1,457	1,446	1,454	1,449	1,455	1,418	1,440	1,397
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.0	-43.5	-75.5	-130.0
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-19.1	-37.6	-78.7
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.9	27.7	33.3
45,301	3.135	Nominal	**Total Resource Cost ($M)**	2,146	2,193	2,286	2,364	2,457	2,460	2,558	2,694	2,808	2,948	3,283	3,782	4,354
	0.13	Real		2,146	2,129	2,155	2,163	2,183	2,122	2,143	2,190	2,216	2,260	2,303	2,428	2,483
	2.36	Nominal	Cost in mills/kWh	47.4	47.4	48.3	48.8	49.6	48.6	49.4	50.9	52.3	54.2	57.0	62.0	67.0
	-0.62	Real		47.4	46.0	45.6	44.7	44.1	41.9	41.3	41.4	41.3	41.5	40.0	39.8	38.2

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.83**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.95**

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10 Percent more Transmission Capacity East to West

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,021	50,476	51,288	52,052	52,969	54,065	55,266	56,678	57,500	58,413	61,967	65,414	68,889
	MWa	5,710	5,762	5,855	5,942	6,047	6,172	6,309	6,470	6,564	6,668	7,074	7,467	7,864
	Total Annual Emissions (1000 Tons)													
0.58%	CO2	56,624	56,980	57,033	57,466	57,521	57,070	57,576	57,876	58,209	58,893	60,316	62,332	63,171
-0.05%	NOx	132.7	132.0	130.8	130.4	132.4	132.5	132.6	131.7	131.7	131.8	132.1	132.7	131.3
0.04%	TSP	11.8	11.8	11.7	11.7	11.8	11.8	11.8	11.8	11.8	11.9	11.9	12.0	11.9
	Annual System Emission Rates (Pounds/MWh)													
-1.10%	CO2	2,264	2,258	2,224	2,208	2,172	2,111	2,084	2,042	2,025	2,016	1,947	1,906	1,834
-1.72%	NOx	5.31	5.23	5.10	5.01	5.00	4.90	4.80	4.65	4.58	4.51	4.27	4.06	3.81
-1.63%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.72	98.23	97.53	95.93	93.25	92.03	90.21	89.43	89.06	85.98	84.18	81.01
	NOx	100	98.53	96.11	94.43	94.18	92.37	90.47	87.61	86.33	85.05	80.38	76.47	71.86
	TSP	100	98.47	96.58	95.28	94.27	92.20	90.30	87.98	86.94	85.87	81.36	77.43	73.20

20 Year Emissions (1000 Tons)	Average	Total
CO2	59,559	1,191,177
NOx	132	2,640
TSP	12	238

10 Percent Reduction in All Transmission Line Capacity

Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.1				31.6		56.1	161.7	437.5	500.0
	DSM Programs	6.9	7.1	7.2	7.2	7.7	7.7	7.9	8.1	8.1	12.4	20.7	24.3	30.6
	OWC Geothermal													
O	OWC Cogen 1													48.3
W	OWC Cogen 2						199.0	199.2	137.1		155.5	275.7	324.7	15.4
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.9**	**7.1**	**7.2**	**7.2**	**7.7**	**206.7**	**207.1**	**145.2**	**8.1**	**167.9**	**296.4**	**349.0**	**94.3**
	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.5	0.6	1.1	1.7	1.9	2.3
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.5**	**0.6**	**1.1**	**1.7**	**1.9**	**2.3**
	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													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													453.4
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	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**	**514.8**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	2.9	3.0	3.0	3.1	4.6	8.1	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**2.9**	**3.0**	**3.0**	**3.1**	**4.6**	**8.1**	**9.5**	**11.9**
T	DSM Programs	21.8	21.6	22.5	23.1	23.6	24.2	24.5	25.3	26.2	40.8	69.8	83.0	106.2
O	Short Term Cap Purch				13.1				31.6		56.1	161.7	437.5	500.0
T	Cogeneration						199.0	199.2	137.1		155.5	275.7	324.7	517.1
A	Combined Cycle CT													
L	All Others													
	Total	**21.8**	**21.6**	**22.5**	**36.2**	**23.6**	**223.2**	**223.7**	**194.0**	**26.2**	**252.4**	**507.2**	**845.2**	**1,123.3**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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)	(113)	(137)	(161)	(187)	(213)	(254)	(323)	(406)	(513)
T	**Total Requirements**	**9,873**	**10,008**	**9,858**	**9,977**	**9,760**	**9,808**	**9,968**	**9,991**	**9,915**	**10,052**	**10,365**	**10,785**	**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				32		56	162	438	500
&	New Resources						199	398	535	535	691	966	1,292	1,808
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**10,877**	**11,061**	**10,991**	**10,963**	**11,058**	**11,401**	**11,865**	**12,422**
	Reserves	1,223	1,178	1,273	998	1,188	1,069	1,093	999	1,048	1,005	1,036	1,078	1,129
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.9	11.0	10.0	10.6	10.0	10.0	10.0	10.0

10 Percent Reduction in All Transmission Line Capacity
Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.4	10.8	16.4	22.1	28.2	34.4	40.6	47.0	53.4	63.2	79.5	98.8	123.1
	OWC Geothermal													
O	OWC Cogen 1													47.8
W	OWC Cogen 2						193.7	356.6	479.3	479.3	587.9	822.6	1,098.9	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.4**	**10.8**	**16.4**	**22.1**	**28.2**	**228.0**	**397.2**	**526.3**	**532.7**	**651.1**	**902.1**	**1,197.7**	**1,282.8**
	DSM Programs	0.4	0.9	1.3	1.7	2.2	2.7	3.1	3.6	4.0	4.9	6.2	7.8	9.7
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.4**	**0.9**	**1.3**	**1.7**	**2.2**	**2.7**	**3.1**	**3.6**	**4.0**	**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	121.7	155.3	199.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													385.8
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.0**	**78.1**	**94.0**	**121.7**	**155.3**	**585.0**
	DSM Programs	2.2	4.5	6.8	9.1	11.4	13.8	16.2	18.6	21.1	24.7	31.4	39.5	49.8
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.4**	**13.8**	**16.2**	**18.6**	**21.1**	**24.7**	**31.4**	**39.5**	**49.8**
	DSM Programs	15.9	31.6	48.0	65.1	82.4	100.3	118.3	137.2	156.6	186.8	238.8	301.4	381.8
	Short Term Cap Purch				0.0				0.0		0.1	0.2	0.4	0.5
T	Cogeneration						193.7	356.6	479.3	479.3	587.9	822.6	1,098.9	1,545.6
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.9**	**31.6**	**48.0**	**65.1**	**82.4**	**294.0**	**474.9**	**616.6**	**635.9**	**774.8**	**1,061.5**	**1,400.7**	**1,927.9**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	848.4	950.5	1,061.1	1,100.5	1,154.1	1,212.2	1,241.6	1,244.8	1,303.1	1,277.6	1,295.4	1,192.2	1,195.7
E	**DSM Programs**	(15.9)	(31.6)	(48.0)	(65.1)	(82.4)	(100.3)	(118.3)	(137.2)	(156.6)	(186.8)	(238.8)	(301.4)	(381.8)
M	**Total Requirements**	8,952.7	8,984.0	8,920.9	8,836.3	8,759.7	8,809.7	8,944.5	8,998.1	8,990.0	9,031.3	9,291.3	9,474.3	9,830.6
	Existing Generation	7,757.2	7,700.6	7,642.4	7,561.1	7,698.3	7,767.0	7,779.3	7,717.9	7,694.9	7,616.5	7,638.5	7,543.3	7,494.8
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	326.1	313.4	313.5	311.5	348.7	353.0	323.1	335.0	350.0	360.9	383.0	387.8	381.1
R	**New Resources**						193.7	356.6	479.3	479.3	588.0	822.7	1,099.3	1,546.1
	Total Resources	8,952.7	8,984.0	8,920.9	8,836.3	8,759.7	8,809.7	8,944.5	8,998.1	8,990.0	9,031.3	9,291.3	9,474.3	9,830.6

10 Percent Reduction in All Transmission Line Capacity

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	32	48	65	82	100	118	137	157	187	239	301	382
			After Conservation													
			System Load (MWa)	5,710	5,761	5,856	5,991	6,096	6,221	6,358	6,519	6,615	6,720	7,126	7,519	7,916
	0.65		Energy Sales (MWa)	5,158	5,256	5,355	5,465	5,576	5,692	5,808	5,917	5,989	6,042	6,354	6,683	7,069
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,179	8,405	8,650	8,973	9,286	9,534	9,772	10,050	10,262	11,328	12,419	14,385
			Net Conservation Assets ($M)	16	33	49	64	78	92	104	117	130	146	182	210	243
			Utility Cost													
45,887	3.24	Nominal	**Operating Revenues ($M)**	2,147	2,193	2,285	2,362	2,454	2,458	2,557	2,683	2,808	2,938	3,282	3,804	4,412
	0.23	Real		2,147	2,129	2,154	2,161	2,181	2,120	2,141	2,181	2,217	2,252	2,302	2,441	2,516
	2.57	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.3	50.2	49.3	50.3	51.8	53.5	55.5	59.0	65.0	71.3
	-0.41	Real		47.5	46.2	45.9	45.2	44.6	42.5	42.1	42.1	42.3	42.5	41.4	41.7	40.6
		Nominal	Average Customer Bill ($)	1,603	1,616	1,656	1,681	1,718	1,693	1,732	1,787	1,842	1,898	2,024	2,251	2,457
		Real		1,603	1,569	1,561	1,538	1,527	1,461	1,451	1,453	1,454	1,455	1,420	1,445	1,401
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.5	-2.9	-3.7	-5.4	-7.8	-10.7	-14.3	-18.5	-24.1	-45.1	-77.8	-133.3
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-5.0	-6.8	-9.3	-19.8	-38.8	-80.9
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.2	26.2	30.7
45,345	3.137	Nominal	**Total Resource Cost ($M)**	2,148	2,196	2,290	2,368	2,462	2,467	2,566	2,693	2,818	2,947	3,284	3,791	4,361
	0.13	Real		2,148	2,132	2,158	2,167	2,187	2,128	2,149	2,190	2,225	2,259	2,304	2,433	2,487
	2.37	Nominal	Cost in mills/kWh	47.4	47.4	48.4	48.9	49.7	48.7	49.5	50.9	52.5	54.1	57.0	62.2	67.1
	-0.61	Real		47.4	46.0	45.6	44.8	44.2	42.0	41.5	41.4	41.4	41.5	40.0	39.9	38.3

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.85**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.99**

10 Percent Reduction in All Transmission Line Capacity

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,020	50,473	51,284	52,047	52,963	54,059	55,260	56,671	57,493	58,410	61,966	65,413	68,888
	MWa	5,710	5,762	5,854	5,941	6,046	6,171	6,308	6,469	6,563	6,668	7,074	7,467	7,864
	Total Annual Emissions (1000 Tons)													
0.58%	CO2	56,491	56,823	56,817	57,152	57,213	56,828	57,347	57,552	57,774	58,424	59,864	61,996	63,071
-0.06%	NOx	132.2	131.4	130.0	129.3	131.3	131.7	131.9	130.7	130.3	130.3	130.7	131.6	130.8
0.05%	TSP	11.8	11.7	11.6	11.6	11.7	11.7	11.7	11.7	11.7	11.7	11.8	11.9	11.9
	Annual System Emission Rates (Pounds/MWh)													
-1.10%	CO2	2,259	2,252	2,216	2,196	2,160	2,102	2,076	2,031	2,010	2,000	1,932	1,896	1,831
-1.73%	NOx	5.29	5.21	5.07	4.97	4.96	4.87	4.77	4.61	4.53	4.46	4.22	4.02	3.80
-1.62%	TSP	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.41	0.40	0.38	0.36	0.34
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.69	98.10	97.23	95.65	93.08	91.89	89.92	88.98	88.57	85.54	83.92	81.07
	NOx	100	98.47	95.91	93.98	93.77	92.16	90.28	87.23	85.70	84.37	79.78	76.11	71.85
	TSP	100	98.30	96.52	94.76	94.02	92.03	90.16	87.89	86.26	85.05	80.66	77.18	73.27

20 Year Emissions (1000 Tons)	Average	Total
CO2	59,255	1,185,098
NOx	131	2,619
TSP	12	235

25 Percent Reduction in Hydro Utilization

Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.1								369.5	491.6
	DSM Programs	6.9	7.1	7.2	7.2	7.7	7.7	7.9	7.8	7.8	12.0	20.5	24.4	30.5
	OWC Geothermal													
O	OWC Cogen 1													
W	OWC Cogen 2													195.9
C	OWC Combined Cycle						380.3	228.1	39.9		103.3	379.3	175.7	
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**6.9**	**7.1**	**7.2**	**7.2**	**7.7**	**388.0**	**236.0**	**47.7**	**7.8**	**115.3**	**399.8**	**200.1**	**226.4**
	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.9	1.6	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.9**	**1.6**	**1.9**	**2.4**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	12.9	13.6	14.3	22.1	39.0	47.2	61.3
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle												55.5	261.6
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**12.9**	**13.6**	**14.3**	**22.1**	**39.0**	**102.7**	**322.9**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	3.0	2.9	3.1	3.0	4.6	8.1	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**3.0**	**2.9**	**3.1**	**3.0**	**4.6**	**8.1**	**9.5**	**11.9**
T	DSM Programs	21.8	21.6	22.5	23.1	23.6	24.3	24.3	25.1	25.7	39.6	69.2	83.0	106.1
O	Short Term Cap Purch				13.1								369.5	491.6
T	Cogeneration						380.3	228.1	39.9		103.3	379.3	231.2	457.5
A	Combined Cycle CT													
L	All Others													
	Total	**21.8**	**21.6**	**22.5**	**36.2**	**23.6**	**404.6**	**252.4**	**65.0**	**25.7**	**142.9**	**448.5**	**683.7**	**1,055.2**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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)	(113)	(137)	(161)	(186)	(212)	(252)	(321)	(404)	(510)
T	**Total Requirements**	**9,873**	**10,008**	**9,858**	**9,977**	**9,760**	**9,808**	**9,968**	**9,992**	**9,916**	**10,054**	**10,367**	**10,787**	**11,295**
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								370	492
&	New Resources						380	608	648	648	752	1,131	1,363	1,819
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**11,058**	**11,271**	**11,072**	**11,076**	**11,063**	**11,404**	**11,868**	**12,425**
	Reserves	1,223	1,178	1,273	998	1,188	1,250	1,303	1,080	1,160	1,008	1,036	1,079	1,129
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	12.7	13.1	10.8	11.7	10.0	10.0	10.0	10.0

25 Percent Reduction in Hydro Utilization

Cumulative Annual Energy (MWa)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	5.4	10.8	16.4	22.1	28.2	34.4	40.6	46.9	53.2	62.8	79.1	98.3	122.6
	OWC Geothermal													
O	OWC Cogen 1													194.0
W	OWC Cogen 2						366.2	544.7	580.5	580.5	639.6	962.5	1,112.0	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													
	Total	**5.4**	**10.8**	**16.4**	**22.1**	**28.2**	**400.6**	**585.4**	**627.4**	**633.7**	**702.5**	**1,041.5**	**1,210.3**	**1,428.6**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	0.5	0.9	1.3	1.8	2.2	2.7	3.1	3.6	4.1	4.8	6.1	7.7	9.7
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.2**	**2.7**	**3.1**	**3.6**	**4.1**	**4.8**	**6.1**	**7.7**	**9.7**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	68.0	78.0	93.6	121.1	154.7	198.5
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2												47.2	269.9
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.0**	**78.0**	**93.6**	**121.1**	**201.9**	**468.5**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	2.2	4.5	6.8	9.1	11.5	13.8	16.2	18.6	21.1	24.7	31.5	40.0	51.1
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.5**	**13.8**	**16.2**	**18.6**	**21.1**	**24.7**	**31.5**	**40.0**	**51.1**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	DSM Programs	15.9	31.6	48.1	65.1	82.5	100.4	118.4	137.1	156.3	185.9	237.8	300.7	382.0
	Short Term Cap Purch				0.0								0.4	0.5
T	Cogeneration						366.2	544.7	580.5	580.5	639.6	962.5	1,159.2	1,575.9
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													
	Storage													
	Total	**15.9**	**31.6**	**48.1**	**65.1**	**82.5**	**466.6**	**663.1**	**717.6**	**736.8**	**825.5**	**1,200.2**	**1,460.3**	**1,958.4**

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	309.1	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	830.6	921.1	1,036.0	1,067.2	1,101.9	1,247.3	1,310.6	1,260.3	1,314.0	1,246.7	1,321.9	1,185.0	1,163.1
E	**DSM Programs**	(15.9)	(31.6)	(48.1)	(65.1)	(82.5)	(100.4)	(118.4)	(137.1)	(156.3)	(185.9)	(237.8)	(300.7)	(382.0)
M	**Total Requirements**	8,935.1	8,954.5	8,895.8	8,803.1	8,707.6	8,844.8	9,013.4	9,013.7	9,001.2	9,001.3	9,318.9	9,467.8	9,797.8

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Existing Generation	7,685.1	7,612.7	7,601.9	7,497.3	7,642.9	7,641.6	7,661.1	7,629.1	7,621.6	7,542.8	7,540.8	7,474.4	7,422.2
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	380.6	371.9	329.0	342.0	352.0	340.9	322.0	338.3	333.2	352.9	368.5	389.9	390.7
R	**New Resources**						366.2	544.7	580.5	580.5	639.6	962.5	1,159.6	1,576.4
	Total Resources	8,935.1	8,954.5	8,895.8	8,803.0	8,707.6	8,844.8	9,013.5	9,013.7	9,001.1	9,001.2	9,318.9	9,467.9	9,797.8

25 Percent Reduction in Hydro Utilization

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	31	48	65	82	100	118	136	156	187	239	301	382
			After Conservation													
			System Load (MWa)	5,710	5,761	5,856	5,992	6,097	6,222	6,359	6,520	6,616	6,720	7,126	7,519	7,916
	0.65		Energy Sales (MWa)	5,159	5,256	5,355	5,465	5,577	5,692	5,809	5,918	5,990	6,043	6,354	6,683	7,069
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,178	8,411	8,720	9,133	9,419	9,609	9,827	10,070	10,291	11,455	12,448	14,437
			Net Conservation Assets ($M)	16	32	48	63	77	90	102	115	128	144	185	219	259
			Utility Cost													
46,251	3.23	Nominal	**Operating Revenues ($M)**	2,166	2,210	2,303	2,379	2,475	2,476	2,595	2,722	2,840	2,960	3,283	3,850	4,452
	0.23	Real		2,166	2,145	2,171	2,177	2,199	2,136	2,173	2,213	2,242	2,268	2,303	2,471	2,539
	2.57	Nominal	Cost in mills/kWh	47.9	48.0	49.1	49.7	50.7	49.7	51.0	52.5	54.1	55.9	59.0	65.8	71.9
	-0.42	Real		47.9	46.6	46.3	45.5	45.0	42.8	42.7	42.7	42.7	42.9	41.4	42.2	41.0
		Nominal	Average Customer Bill ($)	1,617	1,628	1,669	1,694	1,733	1,705	1,758	1,813	1,863	1,912	2,024	2,278	2,480
		Real		1,617	1,581	1,573	1,550	1,540	1,471	1,472	1,474	1,471	1,465	1,420	1,462	1,414
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.0	-43.5	-75.5	-130.0
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-19.1	-37.6	-78.7
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	10.9	13.1	15.5	16.7	18.3	22.9	27.7	33.3
45,727	3.133	Nominal	**Total Resource Cost ($M)**	2,167	2,213	2,307	2,385	2,482	2,484	2,604	2,732	2,850	2,969	3,287	3,840	4,406
	0.13	Real		2,167	2,148	2,175	2,183	2,205	2,143	2,181	2,222	2,250	2,276	2,305	2,465	2,513
	2.36	Nominal	Cost in mills/kWh	47.8	47.8	48.8	49.3	50.1	49.0	50.2	51.6	53.1	54.5	57.1	63.0	67.8
	-0.62	Real		47.8	46.4	46.0	45.1	44.5	42.3	42.1	42.0	41.9	41.8	40.0	40.4	38.7

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **42.22**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **40.32**

25 Percent Reduction in Hydro Utilization

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,021	50,473	51,284	52,047	52,964	54,059	55,260	56,672	57,495	58,417	61,975	65,420	68,886
	MWa	5,710	5,762	5,854	5,941	6,046	6,171	6,308	6,469	6,563	6,669	7,075	7,468	7,864
	Total Annual Emissions (1000 Tons)													
0.56%	CO2	57,451	57,693	57,965	58,168	58,275	57,407	57,968	58,351	58,670	59,356	60,625	62,925	63,895
-0.06%	NOx	133.7	132.6	132.2	131.0	133.1	132.1	132.4	131.7	131.6	131.7	131.6	133.1	132.2
0.08%	TSP	11.9	11.8	11.8	11.8	11.9	11.8	11.8	11.8	11.9	11.9	11.9	12.0	12.1
	Annual System Emission Rates (Pounds/MWh)													
-1.12%	CO2	2,297	2,286	2,261	2,235	2,201	2,124	2,098	2,059	2,041	2,032	1,956	1,924	1,855
-1.73%	NOx	5.35	5.25	5.15	5.03	5.03	4.89	4.79	4.65	4.58	4.51	4.25	4.07	3.84
-1.59%	TSP	0.48	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.41	0.41	0.38	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.52	98.41	97.31	95.80	92.46	91.34	89.65	88.85	88.47	85.17	83.75	80.76
	NOx	100	98.26	96.40	94.14	94.01	91.39	89.65	86.95	85.64	84.34	79.45	76.08	71.79
	TSP	100	98.55	96.54	95.21	94.22	91.76	90.01	87.85	86.71	85.56	80.81	77.41	73.70

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,126	1,202,512
NOx	132	2,645
TSP	12	238

Natural Gas Price Jump 25% in 2003
Resource Locked till 2003
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.3				89.3		196.9	320.0	500.0	500.0
	DSM Programs	6.8	7.1	7.0	7.3	7.7	7.7	7.8	8.5	8.6	12.7	21.3	25.3	31.7
	OWC Geothermal													
O	OWC Cogen 1													161.2
W	OWC Cogen 2						189.0	196.1	91.5		69.9	257.0	419.2	83.9
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													37.3
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**196.7**	**203.9**	**100.0**	**8.6**	**82.6**	**278.3**	**444.5**	**314.1**
	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.7	1.0	1.7	1.9	2.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**1.0**	**1.7**	**1.9**	**2.4**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	13.0	14.0	14.8	22.8	39.4	47.5	61.7
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													295.5
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**13.0**	**14.0**	**14.8**	**22.8**	**39.4**	**47.5**	**357.2**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	3.0	2.9	3.5	3.4	5.2	8.4	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**3.0**	**2.9**	**3.5**	**3.4**	**5.2**	**8.4**	**9.5**	**11.9**
T	DSM Programs	21.7	21.6	22.3	23.2	23.6	24.3	24.3	26.6	27.5	41.7	70.8	84.2	107.7
O	Short Term Cap Purch				13.3				89.3		196.9	320.0	500.0	500.0
T	Cogeneration						189.0	196.1	91.5		69.9	257.0	419.2	540.6
A	Combined Cycle CT													
L	All Others													37.3
	Total	21.7	21.6	22.3	36.5	23.6	213.3	220.4	207.4	27.5	308.5	647.8	1,003.4	1,185.6
	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)	(188)	(215)	(257)	(328)	(412)	(520)
T	**Total Requirements**	9,873	10,008	9,858	9,977	9,761	9,808	9,968	9,990	9,913	10,049	10,360	10,779	11,285
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				89		197	320	500	500
&	New Resources						189	385	477	477	546	804	1,223	1,801
R	**Total Resources**	11,096	11,185	11,131	10,975	10,948	10,867	11,048	10,990	10,905	11,054	11,397	11,858	12,415
	Reserves	1,223	1,178	1,273	998	1,188	1,059	1,080	999	991	1,005	1,036	1,078	1,128
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.8	10.8	10.0	10.0	10.0	10.0	10.0	10.0

Natural Gas Price Jump 25% in 2003
Resource Locked till 2003
Cumulative Annual Energy (MWa)

		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	46.6	53.2	63.2	80.1	100.1	125.4
	OWC Geothermal													
O	OWC Cogen 1													156.7
W	OWC Cogen 2						183.9	344.8	426.7	405.6	465.1	683.8	1,040.6	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													8.3
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**217.6**	**384.7**	**473.3**	**458.9**	**528.4**	**763.9**	**1,140.7**	**1,402.4**
	DSM Programs	0.5	0.9	1.3	1.8	2.2	2.7	3.1	3.7	4.2	5.0	6.4	8.0	10.0
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.2**	**2.7**	**3.1**	**3.7**	**4.2**	**5.0**	**6.4**	**8.0**	**10.0**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	68.3	78.6	94.6	122.3	156.1	200.2
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													251.5
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.3**	**78.6**	**94.6**	**122.3**	**156.1**	**451.7**
	DSM Programs	2.2	4.5	6.8	9.1	11.5	13.8	16.2	19.0	21.9	26.1	33.1	41.2	51.6
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.5**	**13.8**	**16.2**	**19.0**	**21.9**	**26.1**	**33.1**	**41.2**	**51.6**
	DSM Programs	15.7	31.3	47.5	64.6	81.8	99.7	117.6	137.5	157.9	188.9	241.9	305.4	387.2
	Short Term Cap Purch				0.0				0.1		0.2	0.3	0.5	0.5
T	Cogeneration						183.9	344.8	426.7	405.6	465.1	683.8	1,040.6	1,520.2
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													8.3
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**283.6**	**462.4**	**564.3**	**563.5**	**654.3**	**926.0**	**1,346.6**	**1,916.1**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.3	984.0	1,103.0	1,155.7	1,197.6	1,247.4	1,323.1	1,317.4	1,350.2	1,287.9	1,277.8	1,234.6	1,279.7
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(64.6)	(81.8)	(99.7)	(117.6)	(137.5)	(157.9)	(188.9)	(241.9)	(305.4)	(387.2)
M	**Total Requirements**	8,986.8	9,017.8	8,963.3	8,892.1	8,803.9	8,845.7	9,026.7	9,070.4	9,035.7	9,039.4	9,270.7	9,512.7	9,909.1
	Existing Generation	7,774.0	7,713.8	7,661.8	7,605.0	7,742.1	7,808.0	7,902.6	7,879.8	7,842.4	7,784.8	7,802.2	7,679.9	7,623.5
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.4	334.0	336.5	323.4	349.1	357.7	293.8	298.0	321.9	323.4	337.3	347.8	348.2
R	**New Resources**						183.9	344.8	426.8	405.6	465.3	684.1	1,041.1	1,528.9
	Total Resources	8,986.8	9,017.8	8,963.2	8,892.1	8,803.9	8,845.7	9,026.7	9,070.4	9,035.7	9,039.4	9,270.7	9,512.7	9,909.1

Natural Gas Price Jump 25% in 2003
Resource Locked till 2003

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	31	48	65	82	101	120	139	159	190	242	305	386
			After Conservation													
			System Load (MWa)	5,710	5,761	5,856	5,992	6,096	6,221	6,357	6,518	6,613	6,717	7,122	7,515	7,911
	0.65		Energy Sales (MWa)	5,159	5,256	5,355	5,465	5,576	5,691	5,807	5,915	5,987	6,040	6,351	6,679	7,064
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,178	8,403	8,644	8,960	9,254	9,481	9,683	9,930	10,134	11,200	12,403	14,498
			Net Conservation Assets ($M)	16	32	48	63	77	90	103	116	129	146	182	211	245
			Utility Cost													
45,816	3.24	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,282	2,358	2,450	2,451	2,527	2,667	2,772	2,932	3,266	3,776	4,409
	0.24	Real		2,146	2,126	2,151	2,158	2,177	2,115	2,116	2,168	2,188	2,247	2,291	2,424	2,515
	2.58	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.3	50.2	49.2	49.7	51.5	52.9	55.4	58.7	64.5	71.3
	-0.41	Real		47.5	46.2	45.9	45.1	44.6	42.4	41.6	41.8	41.7	42.5	41.2	41.4	40.6
		Nominal	Average Customer Bill ($)	1,602	1,614	1,654	1,678	1,716	1,689	1,712	1,777	1,818	1,894	2,014	2,234	2,456
		Real		1,602	1,567	1,559	1,536	1,524	1,457	1,433	1,445	1,435	1,451	1,413	1,434	1,401
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.7	-2.4	-2.7	-3.5	-5.1	-7.3	-10.1	-13.6	-17.7	-23.0	-43.5	-75.4	-129.9
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.0	-1.6	-2.3	-3.3	-4.7	-6.5	-8.8	-18.9	-37.2	-78.2
			Energy Svc Charge ($M)	1.6	3.3	5.0	6.9	8.9	11.0	13.1	15.6	16.8	18.5	22.6	26.7	31.4
45,289	3.143	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,287	2,364	2,458	2,460	2,536	2,678	2,782	2,941	3,270	3,765	4,362
	0.14	Real		2,147	2,129	2,155	2,163	2,184	2,122	2,124	2,177	2,197	2,254	2,294	2,417	2,488
	2.37	Nominal	Cost in mills/kWh	47.4	47.4	48.4	48.9	49.6	48.6	48.9	50.6	51.8	54.0	56.8	61.8	67.1
	-0.61	Real		47.4	46.0	45.6	44.7	44.1	41.9	41.0	41.1	40.9	41.4	39.8	39.6	38.3

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.80**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.94**

Natural Gas Price Jump 25% in 2003
Resource Locked till 2003

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,022	50,476	51,288	52,052	52,969	54,066	55,267	56,669	57,481	58,391	61,939	65,378	68,840
	MWa	5,710	5,762	5,855	5,942	6,047	6,172	6,309	6,469	6,562	6,666	7,071	7,463	7,858
	Total Annual Emissions (1000 Tons)													
0.63%	CO2	56,584	56,898	56,930	57,409	57,469	57,086	58,054	58,494	58,630	59,438	60,815	62,760	63,746
0.03%	NOx	132.6	131.7	130.4	130.2	132.2	132.6	134.3	133.9	133.1	133.6	133.8	134.2	133.4
0.10%	TSP	11.8	11.7	11.7	11.7	11.8	11.8	11.9	11.9	11.9	12.0	12.0	12.0	12.0
	Annual System Emission Rates (Pounds/MWh)													
-1.05%	CO2	2,262	2,254	2,220	2,206	2,170	2,112	2,101	2,064	2,040	2,036	1,964	1,920	1,852
-1.63%	NOx	5.30	5.22	5.09	5.00	4.99	4.90	4.86	4.72	4.63	4.58	4.32	4.11	3.88
-1.57%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.43	0.42	0.42	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.13	97.50	95.91	93.34	92.86	91.25	90.17	89.99	86.80	84.86	81.86
	NOx	100	98.42	95.95	94.39	94.15	92.51	91.69	89.13	87.39	86.35	81.53	77.47	73.12
	TSP	100	98.60	96.58	95.40	94.39	92.52	91.41	89.29	87.99	87.12	82.15	78.08	74.08

20 Year Emissions (1000 Tons)	Average	Total
CO2	59,895	1,197,901
NOx	133	2,663
TSP	12	239

Natural Gas Price Jump 50% in 2003
Resource Locked till 2003
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.3				153.5	64.0	194.2	387.0	500.0	500.0
	DSM Programs	6.8	7.1	7.0	7.3	7.7	7.7	7.8	8.6	8.7	13.4	22.2	26.3	33.2
	OWC Geothermal													
O	OWC Cogen 1								27.0		135.4	39.7		
W	OWC Cogen 2						189.0	196.1				144.7	482.5	294.3
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													107.9
	OWC Pump Storage													
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**196.7**	**203.9**	**35.6**	**8.7**	**148.8**	**206.6**	**508.8**	**435.4**
	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.7	1.4	2.5	2.7	3.6
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**1.4**	**2.5**	**2.7**	**3.6**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	13.0	14.1	14.9	22.8	40.4	49.0	63.9
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													170.3
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**13.0**	**14.1**	**14.9**	**22.8**	**40.4**	**49.0**	**234.2**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	3.0	2.9	3.5	3.4	5.2	8.4	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**3.0**	**2.9**	**3.5**	**3.4**	**5.2**	**8.4**	**9.5**	**11.9**
T	DSM Programs	21.7	21.6	22.3	23.2	23.6	24.3	24.3	26.8	27.7	42.8	73.5	87.5	112.6
O	Short Term Cap Purch				13.3				153.5	64.0	194.2	387.0	500.0	500.0
T	Cogeneration						189.0	196.1	27.0		135.4	184.4	482.5	464.6
A	Combined Cycle CT													
L	All Others													107.9
	Total	**21.7**	**21.6**	**22.3**	**36.5**	**23.6**	**213.3**	**220.4**	**207.3**	**91.7**	**372.4**	**644.9**	**1,070.0**	**1,185.1**

Annual Summer Peak Capacity (MW)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
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)	(188)	(215)	(258)	(332)	(419)	(532)
T	**Total Requirements**	**9,873**	**10,008**	**9,858**	**9,977**	**9,761**	**9,808**	**9,968**	**9,990**	**9,913**	**10,048**	**10,356**	**10,772**	**11,273**
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				154	64	194	387	500	500
&	New Resources						189	385	413	412	548	732	1,214	1,787
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**10,867**	**11,048**	**10,991**	**10,904**	**11,053**	**11,392**	**11,849**	**12,401**
	Reserves	1,223	1,178	1,273	998	1,188	1,059	1,080	999	991	1,005	1,035	1,077	1,127
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.8	10.8	10.0	10.0	10.0	10.0	10.0	10.0

Natural Gas Price Jump 50% in 2003
Resource Locked till 2003
Cumulative Annual Energy (MWa)

		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	46.7	53.5	64.1	81.7	102.7	129.4
	OWC Geothermal													
O	OWC Cogen 1								26.8	24.4	146.4	173.2	173.2	173.2
W	OWC Cogen 2						183.9	327.8	327.8	327.8	327.8	450.9	861.5	1,112.0
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													22.0
	OWC Pump Storage													
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**217.6**	**367.6**	**401.2**	**405.6**	**538.2**	**705.8**	**1,137.4**	**1,436.6**
	DSM Programs	0.5	0.9	1.3	1.8	2.2	2.7	3.1	3.7	4.2	5.2	6.8	8.7	11.2
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans													
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.2**	**2.7**	**3.1**	**3.7**	**4.2**	**5.2**	**6.8**	**8.7**	**11.2**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	68.3	78.7	94.7	123.4	158.7	205.0
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													145.0
H	Utah Combined Cycle													
	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 Pumped Storage													
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.3**	**78.7**	**94.7**	**123.4**	**158.7**	**350.0**
	DSM Programs	2.2	4.5	6.8	9.1	11.5	13.8	16.2	19.0	21.9	26.1	33.4	42.1	53.4
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2													
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.5**	**13.8**	**16.2**	**19.0**	**21.9**	**26.1**	**33.4**	**42.1**	**53.4**
	DSM Programs	15.7	31.3	47.5	64.6	81.8	99.7	117.6	137.7	158.2	190.1	245.3	312.2	398.9
	Short Term Cap Purch				0.0				0.2	0.1	0.2	0.3	0.4	0.4
T	Cogeneration						183.9	327.8	354.5	352.1	474.2	624.1	1,034.7	1,430.2
O	Combined Cycle CT													
T	Coal													
A	Transmission													
L	Simple Cycle													22.0
	Storage													
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**283.6**	**445.4**	**492.4**	**510.4**	**664.4**	**869.7**	**1,347.3**	**1,851.5**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.3	984.0	1,103.0	1,155.7	1,197.6	1,247.4	1,369.3	1,312.0	1,382.1	1,331.7	1,320.4	1,277.7	1,285.2
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(64.6)	(81.8)	(99.7)	(117.6)	(137.7)	(158.2)	(190.1)	(245.3)	(312.2)	(398.9)
M	**Total Requirements**	8,986.8	9,017.8	8,963.3	8,892.1	8,803.9	8,845.7	9,072.9	9,064.9	9,067.4	9,082.1	9,309.8	9,549.0	9,903.0
	Existing Generation	7,774.0	7,713.8	7,661.8	7,605.0	7,742.1	7,808.0	7,982.8	7,944.9	7,946.8	7,866.6	7,928.2	7,760.4	7,709.3
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.4	334.0	336.5	323.4	349.1	357.7	276.8	299.5	302.5	275.3	310.1	309.6	332.5
R	**New Resources**						183.9	327.8	354.7	352.2	474.3	624.4	1,035.1	1,452.6
	Total Resources	8,986.8	9,017.8	8,963.2	8,892.1	8,803.9	8,845.7	9,072.9	9,064.9	9,067.4	9,082.1	9,309.8	9,549.0	9,903.0

Natural Gas Price Jump 50% in 2003
Resource Locked till 2003

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	32	49	67	84	104	123	143	163	195	248	311	392
			After Conservation													
			System Load (MWa)	5,709	5,760	5,854	5,990	6,094	6,218	6,353	6,514	6,608	6,712	7,117	7,509	7,905
	0.65		Energy Sales (MWa)	5,158	5,255	5,354	5,463	5,574	5,688	5,804	5,911	5,983	6,035	6,346	6,674	7,059
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,179	8,405	8,646	8,961	9,239	9,457	9,720	10,048	10,253	11,271	12,536	14,388
			Net Conservation Assets ($M)	17	33	50	65	80	93	106	120	134	151	188	218	251
			Utility Cost													
45,801	3.25	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,283	2,358	2,451	2,452	2,502	2,656	2,751	2,900	3,277	3,770	4,436
	0.24	Real		2,146	2,127	2,152	2,158	2,177	2,115	2,096	2,159	2,172	2,223	2,299	2,420	2,530
	2.58	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.3	50.2	49.2	49.2	51.3	52.5	54.9	59.0	64.5	71.7
	-0.40	Real		47.5	46.2	45.9	45.1	44.6	42.4	41.2	41.7	41.4	42.0	41.4	41.4	40.9
		Nominal	Average Customer Bill ($)	1,602	1,614	1,654	1,679	1,716	1,689	1,695	1,769	1,805	1,874	2,021	2,231	2,471
		Real		1,602	1,567	1,559	1,536	1,525	1,457	1,420	1,439	1,425	1,436	1,417	1,432	1,409
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.4	-2.8	-3.7	-5.4	-7.7	-10.6	-14.2	-18.5	-23.9	-44.9	-77.4	-132.3
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-4.9	-6.8	-9.2	-19.7	-38.6	-80.5
			Energy Svc Charge ($M)	1.6	3.3	5.1	7.0	9.0	11.1	13.3	15.9	17.2	18.9	23.2	27.3	32.1
45,269	3.147	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,287	2,364	2,458	2,460	2,512	2,667	2,761	2,910	3,281	3,759	4,388
	0.14	Real		2,147	2,129	2,156	2,164	2,184	2,122	2,104	2,168	2,180	2,230	2,301	2,413	2,502
	2.38	Nominal	Cost in mills/kWh	47.4	47.4	48.4	48.9	49.6	48.6	48.5	50.4	51.4	53.5	57.0	61.7	67.5
	-0.61	Real		47.4	46.0	45.6	44.7	44.1	41.9	40.6	41.0	40.6	41.0	40.0	39.6	38.5

Notes:

1) $M = millions of dollars 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **41.81**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **39.92**

Natural Gas Price Jump 50% in 2003
Resource Locked till 2003

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,022	50,476	51,288	52,052	52,969	54,066	55,266	56,667	57,478	58,381	61,909	65,318	68,738
	MWa	5,710	5,762	5,855	5,942	6,047	6,172	6,309	6,469	6,561	6,664	7,067	7,456	7,847
	Total Annual Emissions (1000 Tons)													
0.67%	CO2	56,584	56,898	56,930	57,409	57,469	57,086	58,480	58,827	59,197	59,770	61,382	63,054	64,226
0.10%	NOx	132.6	131.7	130.4	130.2	132.2	132.6	135.8	135.0	135.1	135.1	136.2	135.7	135.1
0.14%	TSP	11.8	11.7	11.7	11.7	11.8	11.8	12.0	12.0	12.0	12.1	12.1	12.1	12.1
	Annual System Emission Rates (Pounds/MWh)													
-1.00%	CO2	2,262	2,254	2,220	2,206	2,170	2,112	2,116	2,076	2,060	2,048	1,983	1,931	1,869
-1.56%	NOx	5.30	5.22	5.09	5.00	4.99	4.90	4.91	4.76	4.70	4.63	4.40	4.16	3.93
-1.52%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.44	0.42	0.42	0.41	0.39	0.37	0.35
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.13	97.50	95.91	93.34	93.54	91.77	91.05	90.51	87.65	85.34	82.60
	NOx	100	98.42	95.95	94.39	94.15	92.51	92.68	89.89	88.67	87.34	82.98	78.40	74.16
	TSP	100	98.60	96.58	95.40	94.39	92.52	92.27	89.79	88.70	87.56	83.01	78.73	74.70

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,191	1,203,820
NOx	134	2,687
TSP	12	240

Natural Gas Price Jump 110% in 2003
Resource Locked till 2003
Incremental Summer Capacity (MW) of Resource Additions

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	Short Term Cap Purch				13.3				143.6	52.9	221.6	420.5	500.0	500.0
	DSM Programs	6.8	7.1	7.0	7.3	7.7	7.7	7.8	9.0	9.0	13.4	22.2	26.4	33.2
	OWC Geothermal													
O	OWC Cogen 1								35.8		96.3	70.0		
W	OWC Cogen 2						189.0	196.1						87.2
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													175.1
	Total	**6.8**	**7.1**	**7.0**	**7.3**	**7.7**	**196.7**	**203.9**	**44.8**	**9.0**	**109.7**	**92.2**	**26.4**	**295.5**
	DSM Programs	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.9	1.0	1.4	2.4	2.8	3.6
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans								6.0		32.9	152.8	122.8	
O	Idaho Htr/Id Trans L													
	Total	**0.6**	**0.5**	**0.6**	**0.5**	**0.6**	**0.6**	**0.6**	**6.9**	**1.0**	**34.3**	**155.2**	**125.6**	**3.6**
	DSM Programs	11.5	11.2	11.9	12.6	12.3	13.0	13.0	14.6	15.3	23.6	40.8	49.2	64.1
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4													243.1
	Utah IGCC CT													
	Utah PC Hunter 4											109.5	290.5	
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													29.2
	Utah Wyo/Ut Tran L													
	Total	**11.5**	**11.2**	**11.9**	**12.6**	**12.3**	**13.0**	**13.0**	**14.6**	**15.3**	**23.6**	**150.3**	**339.7**	**336.4**
	DSM Programs	2.8	2.8	2.8	2.8	3.0	3.0	2.9	3.5	3.4	5.2	8.4	9.5	11.9
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2												226.3	37.7
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.8**	**2.8**	**2.8**	**2.8**	**3.0**	**3.0**	**2.9**	**3.5**	**3.4**	**5.2**	**8.4**	**235.8**	**49.6**
T	DSM Programs	21.7	21.6	22.3	23.2	23.6	24.3	24.3	28.0	28.7	43.6	73.8	87.9	112.8
O	Short Term Cap Purch				13.3				143.6	52.9	221.6	420.5	500.0	500.0
T	Cogeneration						189.0	196.1	35.8		96.3	70.0		87.2
A	Combined Cycle CT													
L	All Others								6.0		32.9	262.3	639.6	485.1
	Total	**21.7**	**21.6**	**22.3**	**36.5**	**23.6**	**213.3**	**220.4**	**213.4**	**81.6**	**394.4**	**826.6**	**1,227.5**	**1,185.1**
	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)	(189)	(218)	(261)	(335)	(423)	(536)
T	**Total Requirements**	**9,873**	**10,008**	**9,858**	**9,977**	**9,761**	**9,808**	**9,968**	**9,989**	**9,910**	**10,045**	**10,353**	**10,768**	**11,269**
E														
M	Existing Generation	9,949	9,994	10,010	9,842	9,848	9,855	9,855	9,760	9,764	9,614	9,472	9,209	9,209
	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				144	53	222	421	500	500
&	New Resources						189	385	427	427	556	889	1,528	2,100
R	**Total Resources**	**11,096**	**11,185**	**11,131**	**10,975**	**10,948**	**10,867**	**11,048**	**10,989**	**10,902**	**11,050**	**11,390**	**11,845**	**12,396**
	Reserves	1,223	1,178	1,273	998	1,188	1,059	1,080	999	991	1,004	1,035	1,077	1,127
	Reserve Margin (RM) (%	12.4	11.8	12.9	10.0	12.2	10.8	10.8	10.0	10.0	10.0	10.0	10.0	10.0

Natural Gas Price Jump 110% in 2003
Resource Locked till 2003
Cumulative Annual Energy (MWa)

		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	47.0	54.1	64.7	82.4	103.5	130.1
	OWC Geothermal													
O	OWC Cogen 1								30.7	30.7	113.2	173.2	172.0	172.0
W	OWC Cogen 2						183.9	327.8	327.8	327.8	327.8	327.8	327.8	401.9
C	OWC Combined Cycle													
	OWC Bridger Trans L													
	OWC Simple Cycle CT													
	OWC Pump Storage													43.5
	Total	**5.2**	**10.5**	**15.9**	**21.6**	**27.6**	**217.6**	**367.6**	**405.4**	**412.5**	**505.7**	**583.3**	**603.2**	**747.5**
	DSM Programs	0.5	0.9	1.3	1.8	2.2	2.7	3.1	3.8	4.4	5.4	7.0	8.9	11.4
I	Idaho Cogen 1													
D	Idaho Cogen 2													
A	Idaho Combined Cycle													
H	Idaho Bridger Trans								5.4	5.4	35.3	174.0	285.6	285.6
O	Idaho Htr/Id Trans L													
	Total	**0.5**	**0.9**	**1.3**	**1.8**	**2.2**	**2.7**	**3.1**	**9.2**	**9.8**	**40.7**	**181.0**	**294.5**	**297.0**
	DSM Programs	7.8	15.4	23.5	32.2	40.6	49.5	58.4	68.8	79.6	96.4	125.4	160.9	207.4
	Utah Wind													
	Utah Geothermal													
U	Utah Solar													
T	Utah Cogen 1													
A	Utah Cogen 2													
H	Utah Combined Cycle													
	Utah IGCC Hunter 4													217.5
	Utah IGCC CT													
	Utah PC Hunter 4											100.3	366.6	366.6
	Utah Coal $23.25/Ton													
	Utah Coal $27.00/Ton													
	Utah Simple Cycle CT													
	Utah Pumped Storage													7.3
	Utah Wyo/Ut Tran L													
	Total	**7.8**	**15.4**	**23.5**	**32.2**	**40.6**	**49.5**	**58.4**	**68.8**	**79.6**	**96.4**	**225.7**	**527.5**	**798.7**
	DSM Programs	2.2	4.5	6.8	9.1	11.5	13.8	16.2	19.0	21.9	26.1	33.4	42.1	53.4
W	Wyo Wind													
Y	Wyo Combined Cycle													
O	Wyo IGCC Wyodak 2													
M	Wyo IGCC CT													
I	Wyo PC Wyodak 2												207.4	241.9
N	Wyo Coal $6.70/Ton													
G	Wyo Simple Cycle CT													
	Total	**2.2**	**4.5**	**6.8**	**9.1**	**11.5**	**13.8**	**16.2**	**19.0**	**21.9**	**26.1**	**33.4**	**249.4**	**295.3**
	DSM Programs	15.7	31.3	47.5	64.6	81.8	99.7	117.6	138.5	160.0	192.6	248.2	315.4	402.4
	Short Term Cap Purch				0.0				0.1	0.0	0.2	0.3	0.3	0.3
T	Cogeneration						183.9	327.8	358.5	358.5	441.0	500.9	499.8	573.9
O	Combined Cycle CT													
T	Coal											100.3	574.0	826.0
A	Transmission								5.4	5.4	35.3	174.0	285.6	285.6
L	Simple Cycle													
	Storage													50.7
	Total	**15.7**	**31.3**	**47.5**	**64.6**	**81.8**	**283.6**	**445.4**	**502.5**	**523.9**	**669.0**	**1,023.8**	**1,674.9**	**2,138.8**
S	**Native Load**	5,417.0	5,484.0	5,595.1	5,748.1	5,870.0	6,013.0	6,168.0	6,348.1	6,463.1	6,598.1	7,055.9	7,512.0	7,989.2
Y	**Pump Storage/Peak Ret**	308.9	309.3	307.2	258.5	258.5	258.5	258.5	258.5	256.6	256.6	256.6	256.6	321.6
S	**Long Term Sales**	2,394.3	2,271.7	2,005.5	1,794.4	1,559.6	1,426.4	1,394.7	1,284.0	1,123.8	1,085.9	922.2	814.9	771.0
T	**Short Term Sales**	882.3	984.0	1,103.0	1,155.7	1,197.6	1,247.4	1,419.2	1,380.0	1,444.5	1,400.9	1,353.0	1,347.9	1,319.7
E	**DSM Programs**	(15.7)	(31.3)	(47.5)	(64.6)	(81.8)	(99.7)	(117.6)	(138.5)	(160.0)	(192.6)	(248.2)	(315.4)	(402.4)
M	**Total Requirements**	8,986.8	9,017.8	8,963.3	8,892.1	8,803.9	8,845.7	9,122.8	9,132.0	9,128.1	9,148.8	9,339.6	9,616.0	9,999.1
	Existing Generation	7,774.0	7,713.8	7,661.8	7,605.0	7,742.1	7,808.0	8,072.9	8,073.2	8,059.3	7,955.4	7,835.8	7,564.0	7,560.0
L	**Long Term Purchases**	869.3	970.0	965.0	963.7	712.7	496.1	485.6	465.9	465.9	465.9	447.1	443.9	408.6
&	**Short Term Purchases**	343.4	334.0	336.5	323.4	349.1	357.7	236.5	228.9	239.0	251.0	281.1	248.5	294.0
R	**New Resources**						183.9	327.8	364.0	363.9	476.4	775.6	1,359.5	1,736.4
	Total Resources	8,986.8	9,017.8	8,963.2	8,892.1	8,803.9	8,845.7	9,122.8	9,132.0	9,128.1	9,148.8	9,339.5	9,616.0	9,999.1

Natural Gas Price Jump 110% in 2003
Resource Locked till 2003

Financial Model Output for 1997-2016 (including end effects to 2046)

50-year NPV at 7.9% ($M)	50-year Annual Growth Rate (%)			1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
			System Load (MWa)	5,725	5,792	5,904	6,057	6,178	6,321	6,477	6,657	6,772	6,907	7,364	7,820	8,298
			Conservation (MWa)	16	32	49	67	84	104	123	143	163	195	248	311	392
			After Conservation													
			System Load (MWa)	5,709	5,760	5,854	5,990	6,094	6,218	6,353	6,514	6,608	6,712	7,117	7,509	7,905
	0.65		Energy Sales (MWa)	5,158	5,255	5,354	5,463	5,574	5,688	5,804	5,911	5,983	6,035	6,346	6,674	7,059
			Total Customers (000's)	1,339	1,357	1,380	1,405	1,428	1,452	1,476	1,501	1,525	1,548	1,622	1,690	1,795
			Net Electric Plant ($M)	8,012	8,179	8,405	8,647	8,963	9,248	9,477	9,725	10,045	10,319	11,771	13,321	15,531
			Net Conservation Assets ($M)	17	33	50	65	80	93	106	120	134	151	188	218	251
			Utility Cost													
44,717	3.13	Nominal	**Operating Revenues ($M)**	2,146	2,190	2,283	2,358	2,451	2,452	2,442	2,597	2,691	2,851	3,184	3,591	4,303
	0.13	Real		2,146	2,127	2,152	2,158	2,177	2,115	2,045	2,112	2,124	2,185	2,233	2,305	2,454
	2.47	Nominal	Cost in mills/kWh	47.5	47.6	48.7	49.3	50.2	49.2	48.0	50.2	51.4	53.9	57.3	61.4	69.6
	-0.51	Real		47.5	46.2	45.9	45.1	44.6	42.4	40.2	40.8	40.5	41.3	40.2	39.4	39.7
		Nominal	Average Customer Bill ($)	1,602	1,614	1,654	1,679	1,716	1,689	1,654	1,730	1,765	1,842	1,964	2,124	2,397
		Real		1,602	1,567	1,559	1,536	1,525	1,457	1,385	1,407	1,393	1,411	1,377	1,364	1,367
			Total Resource Cost													
			DSR Customer Cost ($M)	-1.8	-2.4	-2.8	-3.7	-5.4	-7.7	-10.6	-14.2	-18.5	-23.9	-44.9	-77.4	-132.3
			Levelized (20-year at 7.9%)	-0.2	-0.4	-0.7	-1.1	-1.6	-2.4	-3.5	-4.9	-6.8	-9.2	-19.7	-38.6	-80.5
			Energy Svc Charge ($M)	1.6	3.3	5.1	7.0	9.0	11.1	13.3	15.9	17.2	18.9	23.2	27.3	32.1
44,185	3.03	Nominal	**Total Resource Cost ($M)**	2,147	2,193	2,287	2,364	2,458	2,460	2,452	2,608	2,701	2,861	3,188	3,579	4,255
	0.03	Real		2,147	2,129	2,156	2,164	2,184	2,122	2,053	2,121	2,132	2,192	2,236	2,297	2,426
	2.26	Nominal	Cost in mills/kWh	47.4	47.4	48.4	48.9	49.6	48.6	47.3	49.3	50.3	52.6	55.4	58.7	65.5
	-0.72	Real		47.4	46.0	45.6	44.7	44.1	41.9	39.6	40.1	39.7	40.3	38.8	37.7	37.3

Notes:

1) $M = millions of dollars 2) General Inflation Rate is 3.0% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **40.82**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **38.96**

Natural Gas Price Jump 110% in 2003
Resource Locked till 2003

Net System Projected Emissions

Annual Growth Rate		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2009	2012	2016
	System Energy													
	GWh	50,022	50,476	51,288	52,052	52,969	54,066	55,266	56,660	57,464	58,359	61,884	65,290	69,277
	MWa	5,710	5,762	5,855	5,942	6,047	6,172	6,309	6,468	6,560	6,662	7,064	7,453	7,908
	Total Annual Emissions (1000 Tons)													
1.10%	CO2	56,584	56,898	56,930	57,409	57,469	57,086	58,930	59,526	59,827	60,465	62,379	67,085	69,610
0.32%	NOx	132.6	131.7	130.4	130.2	132.2	132.6	137.3	137.4	137.3	137.5	138.1	139.9	140.7
0.38%	TSP	11.8	11.7	11.7	11.7	11.8	11.8	12.1	12.2	12.2	12.2	12.3	12.6	12.7
	Annual System Emission Rates (Pounds/MWh)													
-0.62%	CO2	2,262	2,254	2,220	2,206	2,170	2,112	2,133	2,101	2,082	2,072	2,016	2,055	2,010
-1.39%	NOx	5.30	5.22	5.09	5.00	4.99	4.90	4.97	4.85	4.78	4.71	4.46	4.29	4.06
-1.32%	TSP	0.47	0.47	0.46	0.45	0.45	0.44	0.44	0.43	0.42	0.42	0.40	0.38	0.37
	Emission Rates as Percent of 1997 Base													
	CO2	100	99.65	98.13	97.50	95.91	93.34	94.26	92.87	92.04	91.59	89.11	90.83	88.83
	NOx	100	98.42	95.95	94.39	94.15	92.51	93.76	91.53	90.15	88.87	84.19	80.85	76.65
	TSP	100	98.60	96.58	95.40	94.39	92.52	93.16	91.00	89.69	88.49	84.00	81.61	77.67

20 Year Emissions (1000 Tons)	Average	Total
CO2	61,878	1,237,550
NOx	137	2,732
TSP	12	244

RAMPP-5 Base Case
(Including 15% DSM Advantage)
Incremental Summer Capacity (MW) of Resource Additions

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
	Short Term Cap Purch												291.4
	DSM Programs	6.0	5.8	6.3	6.2	6.3	6.3	6.3	6.3	6.4	6.4	23.6	37.8
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2											182.7	468.0
C	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**6.0**	**5.8**	**6.3**	**6.2**	**6.3**	**6.3**	**6.3**	**6.3**	**6.4**	**6.4**	**206.3**	**505.8**
	DSM Programs	0.5	0.5	0.5	0.5	0.6	0.6	0.7	0.6	0.6	0.6	2.3	3.1
I	Idaho Cogen 1												
D	Idaho Cogen 2												
A	Idaho Combined Cycle												
H	Idaho Bridger Trans												
O	Idaho Htr/Id Trans L												
	Total	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.7**	**0.6**	**0.6**	**0.6**	**2.3**	**3.1**
	DSM Programs	11.1	10.7	10.2	10.6	10.8	10.2	10.8	10.3	10.2	10.6	47.5	74.1
	Utah Wind												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle												
	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 Pumped Storage												
	Utah Wyo/Ut Tran L												
	Total	**11.1**	**10.7**	**10.2**	**10.6**	**10.8**	**10.2**	**10.8**	**10.3**	**10.2**	**10.6**	**47.5**	**74.1**
	DSM Programs	1.9	2.0	2.0	2.1	2.2	2.3	2.3	2.3	2.3	2.3	8.7	14.5
W	Wyo Wind												
Y	Wyo Combined Cycle												
O	Wyo IGCC Wyodak 2												
M	Wyo IGCC CT												
I	Wyo PC Wyodak 2												
N	Wyo Coal $6.70/Ton												
G	Wyo Simple Cycle CT												
	Total	**1.9**	**2.0**	**2.0**	**2.1**	**2.2**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**8.7**	**14.5**
T	DSM Programs	19.5	19.0	19.0	19.4	19.9	19.4	20.1	19.5	19.5	19.9	82.1	129.5
O	Short Term Cap Purch												291.4
T	Cogeneration											182.7	468.0
A	Combined Cycle CT												
L	All Others												
	Total	**19.5**	**19.0**	**19.0**	**19.4**	**19.9**	**19.4**	**20.1**	**19.5**	**19.5**	**19.9**	**264.8**	**888.9**

Annual Summer Peak Capacity (MW)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
S	Native Load	7,526	7,589	7,659	7,693	7,562	7,705	7,849	8,008	8,162	8,317	9,105	9,938
Y	Long Term Sales	2,593	2,525	2,444	2,091	1,845	1,793	1,593	1,370	1,362	1,112	987	842
S	DSM Programs	(19)	(39)	(57)	(77)	(97)	(116)	(136)	(156)	(175)	(195)	(277)	(407)
T	**Total Requirements**	**10,100**	**10,075**	**10,046**	**9,707**	**9,310**	**9,382**	**9,306**	**9,222**	**9,349**	**9,234**	**9,815**	**10,373**
E													
M	Existing Generation	9,965	10,076	9,934	9,940	9,955	9,862	9,866	9,749	9,753	9,757	9,627	9,627
	Long Term Purchases	1,023	996	992	970	723	707	558	558	558	558	440	418
L	Short Term Market	220	440	660	880	1,122	1,085	1,035	812	805	554	548	423
&	Short Term Cap Purch												291
R	New Resources											183	651
	Total Resources	**11,208**	**11,512**	**11,586**	**11,790**	**11,800**	**11,654**	**11,458**	**11,119**	**11,115**	**10,869**	**10,797**	**11,410**
	Reserves	1,109	1,436	1,541	2,083	2,490	2,274	2,153	1,897	1,766	1,635	982	1,037
	Reserve Margin (RM) (%	11.0	14.3	15.3	21.5	26.8	24.2	23.1	20.6	18.9	17.7	10.0	10.0

RAMPP-5 Base Case

Cumulative Annual Energy (MWa)

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017
	DSM Programs	4.4	8.7	13.3	18.0	22.6	27.3	32.0	36.7	41.5	46.3	64.1	93.0
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2											168.5	599.0
C	OWC Combined Cycle												
	OWC Bridger Trans L												
	OWC Simple Cycle CT												
	OWC Pump Storage												
	Total	**4.4**	**8.7**	**13.3**	**18.0**	**22.6**	**27.3**	**32.0**	**36.7**	**41.5**	**46.3**	**232.6**	**692.0**
	DSM Programs	0.4	0.8	1.2	1.6	2.0	2.5	3.0	3.4	3.9	4.4	6.1	8.6
I	Idaho Cogen 1												
D	Idaho Cogen 2												
A	Idaho Combined Cycle												
H	Idaho Bridger Trans												
O	Idaho Htr/Id Trans L												
	Total	**0.4**	**0.8**	**1.2**	**1.6**	**2.0**	**2.5**	**3.0**	**3.4**	**3.9**	**4.4**	**6.1**	**8.6**
	DSM Programs	7.2	14.1	20.6	27.4	34.3	40.8	47.7	54.4	60.9	67.7	99.0	148.4
	Utah Wind												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle												
	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 Pumped Storage												
	Utah Wyo/Ut Tran L												
	Total	**7.2**	**14.1**	**20.6**	**27.4**	**34.3**	**40.8**	**47.7**	**54.4**	**60.9**	**67.7**	**99.0**	**148.4**
	DSM Programs	1.6	3.1	4.8	6.5	8.2	10.0	11.7	13.5	15.4	17.2	24.1	35.8
W	Wyo Wind												
Y	Wyo Combined Cycle												
O	Wyo IGCC Wyodak 2												
M	Wyo IGCC CT												
I	Wyo PC Wyodak 2												
N	Wyo Coal $6.70/Ton												
G	Wyo Simple Cycle CT												
	Total	**1.6**	**3.1**	**4.8**	**6.5**	**8.2**	**10.0**	**11.7**	**13.5**	**15.4**	**17.2**	**24.1**	**35.8**
	DSM Programs	13.5	26.7	39.9	53.4	67.1	80.5	94.4	108.1	121.6	135.6	193.3	285.7
	Short Term Cap Purch												0.1
T	Cogeneration											168.5	599.0
O	Combined Cycle CT												
T	Coal												
A	Transmission												
L	Simple Cycle												
	Storage												
	Total	**13.5**	**26.7**	**39.9**	**53.4**	**67.1**	**80.5**	**94.4**	**108.1**	**121.6**	**135.6**	**361.7**	**884.9**
S	**Native Load**	5,501.5	5,544.6	5,591.0	5,625.2	5,530.7	5,644.1	5,755.4	5,869.5	5,985.9	6,112.4	6,719.3	7,375.0
Y	**Pump Storage/Peak Ret**	296.5	293.5	258.5	249.1	235.2	257.6	258.1	242.3	256.6	256.6	256.6	256.6
S	**Long Term Sales**	2,233.6	2,039.0	1,866.2	1,535.3	1,400.4	1,350.3	1,239.6	1,068.7	1,030.8	907.1	814.7	730.7
T	**Short Term Sales**	951.2	1,234.4	1,506.9	1,774.3	1,848.8	1,759.4	1,696.2	1,665.0	1,517.6	1,473.1	1,193.7	1,147.9
E	**DSM Programs**	(13.5)	(26.7)	(39.8)	(53.3)	(67.1)	(80.5)	(94.4)	(108.1)	(121.6)	(135.6)	(193.3)	(285.7)
M	**Total Requirements**	8,969.3	9,084.9	9,182.7	9,130.6	8,948.1	8,930.8	8,854.8	8,737.5	8,669.2	8,613.6	8,791.0	9,224.4
	Existing Generation	7,658.6	7,681.2	7,597.7	7,576.7	7,503.5	7,516.4	7,693.5	7,775.0	7,746.2	7,769.9	7,764.9	7,801.7
L	**Long Term Purchases**	756.6	764.9	756.1	589.2	397.4	395.7	373.6	373.6	373.7	354.8	351.7	316.6
&	**Short Term Market**	220.0	440.1	660.0	785.4	931.3	908.8	617.7	407.3	403.3	277.9	212.1	212.1
R	**Short Term Purchases**	334.0	198.8	169.0	179.2	115.9	109.9	170.0	181.6	146.0	211.0	293.8	294.9
	New Resources											168.5	599.2
	Total Resources	8,969.3	9,084.9	9,182.7	9,130.5	8,948.1	8,930.8	8,854.8	8,737.5	8,669.2	8,613.6	8,791.0	9,224.4