IDAHO POWER
An IDACORP Company

2004 INTEGRATED RESOURCE PLAN

Providing a foundation for a bright future.

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July 2004

Idaho Power Company

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Glossary of Acronyms

A/C – Air Conditioning
AEO – Annual Energy Outlook
AIR – Additional Information Requests
aMW or MWa – Average Megawatt
BPA – Bonneville Power Administration
CCCT – Combined-Cycle Combustion Turbine
CHP – Combined Heat and Power
CO_2 – Carbon Dioxide
CT – Combustion Turbine
DOE – Department of Energy
DG – Distributed Generation
DSM – Demand-Side Management
EA – Environmental Assessment
EEAG – Energy Efficiency Advisory Group
EIA – Energy Information Administration
EIS – Environmental Impact Statement
ESA – Endangered Species Act
FERC – Federal Energy Regulatory Commission
IOU – Investor-Owned Utility
IPC – Idaho Power Company
IPUC – Idaho Public Utilities Commission
IRP – Integrated Resource Plan
IRPAC – Integrated Resource Plan Advisory Council
kV – Kilovolt
kW – Kilowatt
kWh – Kilowatt hour
LIWA – Low-Income Weatherization Assistance
MAF – Million Acre Feet
MMBTU – Million British Thermal Units
MW – Megawatt
MWh – Megawatt hour
NEEA – Northwest Energy Efficiency Alliance
NWPCC – Northwest Power and Conservation Council
NOx – Nitrogen Oxides
OPUC – Oregon Public Utility Commission
PM&E – Protection, Mitigation and Enhancement
PTC – Production Tax Credit
QF – Qualifying Facility
RFP – Request for Proposal
RTO – Regional Transmission Organization
SO_2 – Sulfur Dioxide
WACC – Weighted Average Cost of Capital
WECC – Western Electricity Coordinating Council

1. Integrated Resource Plan Summary

Introduction

The 2004 Integrated Resource Plan (IRP) is Idaho Power Company's (IPC or the Company) seventh resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC).

Idaho Power Company worked with representatives of major stakeholders to develop the 2004 Integrated Resource Plan. Members of the environmental community, major industrial customers, irrigation representatives, state legislators, PUC representatives, the Governor's office, and others formed the Integrated Resource Plan Advisory Council (IRPAC) and made significant contributions to this plan. The 2004 IRP reflects the combined knowledge and input from the representatives and some of the IRPAC members may submit separate documents and letters expressing their views regarding the 2004 IRP and the planning process.

Based on legislative actions in Oregon and Idaho, the 2004 Integrated Resource Plan assumes that during the planning period, from 2004 through 2013, Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its Idaho and Oregon certificated service areas and will continue to operate as a vertically-integrated electric utility.

The two primary goals of the 2004 Integrated Resource Plan are to:

1. Identify sufficient resources to reliably serve the growing demand for energy service within the Idaho Power Company service territory throughout the 10-year planning period.
2. Ensure that the portfolio of resources selected balances cost, risk, and environmental concerns.

In addition, there are two secondary goals:

a. To give equal and balanced treatment to both supply-side resources and demand side measures
b. To involve the public in the planning process in a meaningful way.

The number of households in the Idaho Power Company service territory is expected to increase from around 320,000 today to over 380,000 by the end of the planning period in 2013. Population growth in Southern Idaho is an inescapable fact, and IPC will need physical resources to meet the electrical energy demands of the additional customers.

Idaho Power Company has an obligation to serve customer loads regardless of the water conditions that may occur. In light of the public input and regulatory support of the 2002 IRP planning criteria, IPC will continue to emphasize a resource plan based upon a worse-than-median level of water. In the 2004 Integrated Resource Plan, IPC is again emphasizing the 70^{th} percentile water conditions and 70^{th} percentile load conditions for resource planning. The water-planning criteria are discussed further in Chapter 4.

Potential Resource Portfolios

Idaho Power Company examined 12 resource portfolios as part of the 2004 Integrated Resource Plan. Idaho Power Company initially presented eight resource portfolios. Discussions with the IRP Advisory Council led to four additional resource portfolios. Of the 12 portfolios, the top five were selected for additional risk analysis – a portfolio that emphasized coal-fired generation, a portfolio with a wind generation emphasis and a natural gas-fired generation backup, and three diversified portfolios. Following the risk analysis, a diversified portfolio with nearly equal amounts of renewable generation and traditional thermal generation was selected as the preferred resource portfolio.

The selected portfolio will increase Idaho Power Company's power supply by approximately 800 aMW and increase the capacity of the system by almost 940 MW over the planning horizon. The balanced portfolio selected for this plan is composed of:

– 76 MW Demand Response Programs (DSM)

– 48 MW Energy Efficiency Programs (DSM)

– 350 MW Wind-Powered Generation

– 100 MW Geothermal-Powered Generation

– 48 MW Combined Heat and Power at Customer Facilities

– 88 MW Simple-Cycle Natural Gas Fired Combustion Turbines

– 62 MW Combustion Turbine, Distributed Generation, or Market Purchases

– 500 MW Coal-Fired Generation

The proposed resource portfolio represents resource acquisition targets. It is important to note that the actual resource portfolio may differ from the above quantities depending on the response to Idaho Power Company's requests for proposals.

Risk Management

Idaho Power, in conjunction with the IPUC staff and interested customer groups, developed a risk management policy during 2001 to protect against severe movements in the Company's power supply costs. The risk management policy is primarily aimed at managing short-term market purchases and hedging strategies with a typical time horizon of 18 months or less. The risk management policy is intended to supplement the existing IRP process.

Whereas the IRP is the forum for making long-term resource decisions, the risk management policy addresses the short-term resource decisions that arise as resources, loads, costs of service, market conditions, and weather vary. The Risk Management Committee oversees both the implementation of the risk management policy and the Integrated Resource Plan to ensure a consistent and coordinated approach.

Idaho Power intends to issue requests for proposals (RFPs) and acquire a variety of resource types including, renewable, thermal, demand-side programs, and combined heat and power early in the planning period. Should any of these resources differ from the expected levels of production and reliability, Idaho Power will be able to adjust the resource proportions in later resource plans. In addition, should market or policy conditions dramatically change, the customers of Idaho Power Company will have the protection of a diverse resource portfolio.

Near-Term Action Plan

Customer growth is the primary driving force behind Idaho Power Company's need for additional resources. Population growth throughout Southern Idaho – specifically, in the Treasure Valley – requires additional resources to meet both instantaneous peak and sustained energy needs. The Company's data, projections, and analyses show that a blended approach based on a diversified portfolio of resources is the most cost-effective, least-risk, and environmentally responsible method to address the increasing energy demands of Idaho Power customers.

Idaho Power has selected a balanced portfolio containing renewable resources, demand-side measures, and thermal generation to meet the projected electric demands over the next ten years. The 2004 Integrated Resource Plan identifies specific actions to be taken by Idaho Power Company prior to the next IRP in 2006:

Fall 2004

- Issue the RFP for 200 MW wind resource
- Issue the RFP for the combustion turbine peaking resource.
- Proceed with the Borah-West transmission upgrade
- File a supplement to the 2004 IRP presenting the results of the ongoing demand-side management studies
- File for an energy efficiency tariff rider with the Oregon PUC

2005

- Design demand-side measures in coordination with the Energy Efficiency Advisory Group and the Public Utility Commissions
- Issue RFP for 12 MW CHP
- Issue the RFP for 100 MW geothermal resource

Idaho Power intends to issue various requests for proposals starting in the fall of 2004. Actual size and configuration of the resources and demand-side programs may vary depending on the specific vendor responses to the requests for proposals. In the event that bidders are not responsive or if the pricing is not competitive, the resource portfolio identified in the IRP may have to be adjusted. In addition, should bidders propose especially attractive responses to the RFPs, Idaho Power Company may alter the resource proportions.

Renewable Resource Education, Research, and Development

Idaho Power Company's resource portfolio has always emphasized renewable resources. The Company's foundation was the Swan Falls Dam on the Snake River – a renewable resource that is still in operation today nearly 100 years later. Idaho Power Company continues to support renewable resource education, research, and development. Idaho Power will continue its commitment to fund educational and demonstration energy projects with up to $100,000 of support for the following near-term research, education, and demonstration projects:

1. Idaho Power Company will support the Foothills Environmental Learning Center to be built near Hull's Gulch on the north side of Boise including the installation of a 4.6 kW fuel cell and a 2.0 kW solar panel at the center.
2. Idaho Power Company will repair and upgrade the 15 kW demonstration solar energy project on the roof of the Idaho Power Corporate headquarters in downtown Boise.

Idaho Power Company's most significant commitment to renewable resources is the intention to add approximately 450 MW of renewable energy resources to the Company's generation portfolio.

Portfolio Composition

In 2013, after the projects identified in the 2004 Integrated Resource Plan preferred portfolio are completed, Idaho Power Company's resource portfolio will contain approximately:

- 1,800 MW Hydro
- 1,520 MW Coal-Fired Generation
- 350 MW Wind Powered Generation
- 340 MW Natural Gas Combustion Turbines
- 100 MW Geothermal Powered Generation
- 48 MW Combined Heat and Power
- 124 MW Demand-Side Progams

The diversified resource portfolio will allow Idaho Power Company to continue to serve its customers while balancing cost, risk, and environmentally concern.

IRP Methodology

A brief outline of the IRP methodology is as follows:

1. Assess the present and future conditions
   - Develop the load forecast
   - Develop the hydrologic forecast
   - Develop generation and transmission forecasts
   - Determine energy surplus and deficiency on a monthly basis
   - Develop a peak-hour transmission analysis to estimate transmission deficiencies
   - Determine energy (monthly) and capacity (peak hour) targets
2. Inventory the potential resource and DSM program options and select a portfolio
   - Estimate the costs of potential supply-side resources and demand-side programs
   - Construct practical portfolios based on supply-side resource and demand-side program costs and estimates
   - Analyze the generation performance and financial costs of the different portfolios
   - Rank the portfolios and select the top five portfolios for further risk analysis
3. Test the top five portfolios to identify a preferred portfolio
   - Refine the transmission analysis for the top five portfolios
   - Perform financial risk analysis
   - Perform policy risk analysis
   - Perform market risk analysis
   - Discuss the qualitative risks
   - Identify the preferred portfolio
4. Develop the action plans based on the preferred portfolio
   - Develop the ten-year action plan
   - Develop the near-term action plan

2. Idaho Power Company Today

Customer and Load Growth

In 1990, Idaho Power Company had almost 290,000 general business customers. Today, Idaho Power Company serves almost 425,000 general business customers in Idaho and Oregon. Firm peak load has increased from less than 2,100 MW in 1990 to nearly 3,000 MW in the summers of 2002 and 2003. Average firm load has increased from 1,200 aMW in 1990 to 1,660 aMW today. Summaries of Idaho Power load and customer data are shown in Table 1 and Figure 1.

Table 1 Idaho Power Company Historical Data (1990 through 2003)

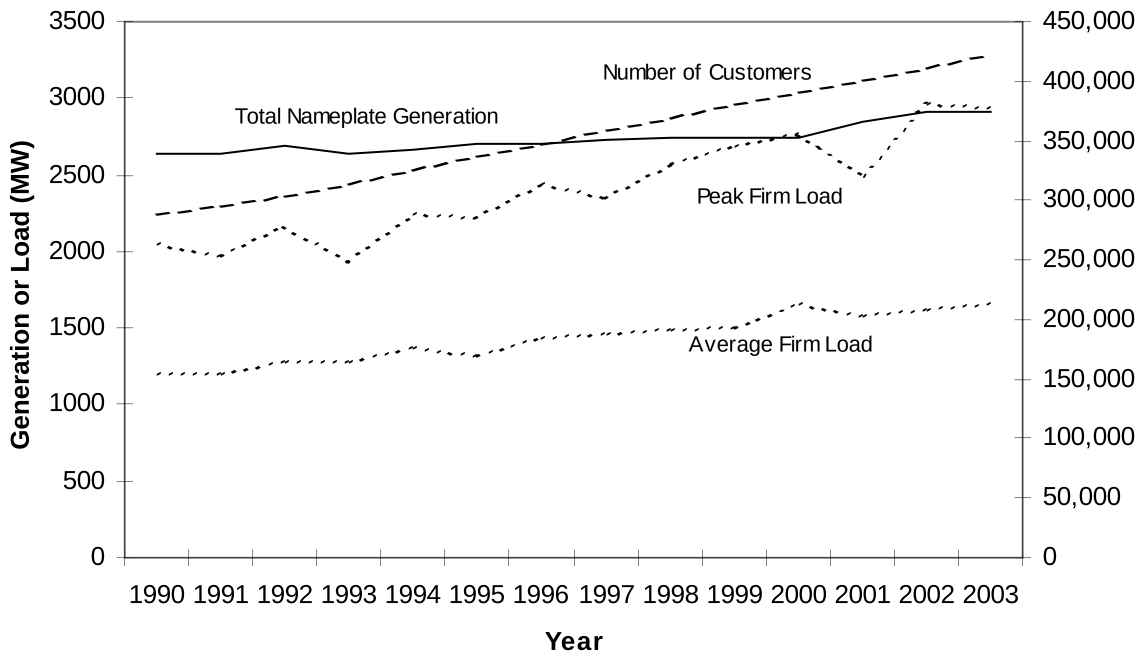
Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers
1990	2,635	2,052	1,206	289,398
1991	2,635	1,972	1,207	295,670
1992	2,694	2,164	1,282	303,962
1993	2,644	1,935	1,274	314,255
1994	2,661	2,245	1,375	325,988
1995	2,703	2,224	1,325	336,795
1996	2,703	2,437	1,439	348,188
1997	2,728	2,352	1,458	358,938
1998	2,738	2,578	1,487	369,803
1999	2,738	2,689	1,503	381,311
2000	2,738	2,765	1,654	390,851
2001	2,851	2,500	1,576	400,724
2002	2,912	2,963	1,623	411,555
2003	2,912	2,944	1,658	423,167

More detailed information is included in the Technical Appendix to the 2004 Integrated Resource Plan.

Simple calculations using the data in Table 1 suggest that each new customer adds over 6 kW to the peak load and over 3 kW to the average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak load, whereas industrial customers contribute more to the average load. Industrial customers generally have a flatter load shape whereas residential, commercial, and irrigation customers have a load shape with greater variation.

Since 1990, Idaho Power Company total nameplate generation has increased by 277 MW – or 277,000 kW – to slightly over 2,900 MW. Total nameplate generation is the rated output of all generation facilities. Actual generation is lower than total nameplate generation due to factors such as hydrological conditions, fuel purity, maintenance, and facility wear and tear. The 277 MW increase in capacity represents enough generation to serve about 46,000 customers at peak times and represents the average energy requirements of

Figure 1 Historical Data (1990 through 2003)



about 92,000 customers. Idaho Power Company generation upgrades, including the removal of the Wood River turbine, are shown in Table 2.

Since 1990, Idaho Power Company has added 135,000 new customers, which equals the combined population of Nampa and Meridian. The simple peak and average energy calculations mentioned earlier suggest that the additional 135,000 customers require over 800 additional MW of on-peak capacity and over 400 MW of average energy.

Idaho Power Company anticipates adding over 10,000 customers each year throughout the 10-year planning period. The same simple calculations suggest that peak load requirements are expected to grow at over 60 MW per year and average energy is forecast to grow at over 30 aMW per year. More detailed customer and load forecasts are discussed in Chapter 3 of this Integrated Resource Plan, and in the Sales and Load Forecast appendix to the 2004 IRP.

The simple peak energy calculations indicate that Idaho Power Company will need to add peaking capacity equivalent to the 90 MW Danskin Plant every 18 months or peaking capacity equivalent to the 162 MW Bennett Mountain Plant every two and a half years, throughout the entire planning period. The actual energy plans to meet the requirements of the new customers are discussed in Chapters 7 and 8.

Table 2 Idaho Power Company Generation Upgrades

Resource	Type	Capacity (MW)	Year
Milner (addition)	Hydro	60	1992
Swan Falls (upgrade)	Hydro	15	1994, 1995
Twin Falls (upgrade)	Hydro	44	1995
Jim Bridger (upgrade)	Thermal	92	1997, 1998, 2002
Boardman (upgrade)	Thermal	3	1997
Valmy (upgrade)	Thermal	23	2001
Danskin (addition)	Thermal	90	2001
Wood River Turbine (removal)	Thermal	-50	1993

Supply-Side Resources

Idaho Power Company has over 2900 MW of installed generation including over 1200 MW of thermal generation (nameplate capacity). In 2003, hydroelectric generation supplied 37 percent of the customers' energy needs, thermal generation supplied 42 percent, and purchased power supplied the remaining 21 percent of the customers' energy needs.

Hydro Resources

Idaho Power operates 17 hydroelectric generating plants located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,707 MW and annual generation equal to approximately 1,057 aMW, or 9.3 million MWh, annually under median water conditions. The Idaho Power Company supply-side resources are listed in Table 3.

The backbone of Idaho Power Company's hydroelectric system is the Hells Canyon Complex in the Hells Canyon reach of the middle Snake River. The Hells Canyon Complex consists of the Brownlee, Oxbow, and Hells Canyon dams and the associated generating facilities. The three plants provide approximately 70 percent of Idaho Power Company's annual hydroelectric generation and nearly 40 percent of the total energy generation. The Hells Canyon Complex alone annually generates approximately 6.2 million MWh, or 708 aMW, of energy under median water conditions. Water storage in the Brownlee reservoir also enables the Hells Canyon Complex to provide the major portion of Idaho Power Company's peaking and load-following capability.

Idaho Power's hydroelectric facilities upstream from Hells Canyon include the American Falls, Milner, Twin Falls, Shoshone Falls, Clear Lake, Thousand Springs, Upper and Lower Malad, Upper and Lower Salmon, Bliss, CJ Strike, Swan Falls and Cascade generating plants. Although the mid-Snake projects (Upper and Lower Salmon, Bliss, and CJ Strike) typically follow run-of-river operations, the Lower Salmon, Bliss, and CJ Strike plants do provide a limited amount of peaking and load following. When possible, the schedules at these plants are adjusted within the FERC license requirements to coincide with the daily system peak demand. All of the other upstream plants utilize run-of-river streamflow for generation.

Table 3 Idaho Power Company Supply-Side Resources

Resource	Type	Capacity (MW)	Location
American Falls	Hydro	92	Upper Snake
Bliss	Hydro	75	Mid-Snake
Brownlee	Hydro	585	Hells Canyon
Cascade	Hydro	12	N Fork Payette
Clear Lake	Hydro	3	S Central Idaho
Hells Canyon	Hydro	392	Hells Canyon
Lower Malad	Hydro	14	S Central Idaho
Upper Malad	Hydro	8	S Central Idaho
Milner	Hydro	59	Upper Snake
Oxbow	Hydro	190	Hells Canyon
Shoshone Falls	Hydro	13	Upper Snake
Lower Salmon	Hydro	60	Mid-Snake
Upper Salmon	Hydro	35	Mid-Snake
CJ Strike	Hydro	83	Mid-Snake
Swan Falls	Hydro	25	Mid-Snake
Thousand Springs	Hydro	9	S Central Idaho
Twin Falls	Hydro	53	Mid-Snake
Boardman	Thermal (Coal)	56	N Central Oregon
Jim Bridger	Thermal (Coal)	771	SW Wyoming
Valmy	Thermal (Coal)	284	N Central Nevada
Bennett Mountain (2005)	Thermal (Natural Gas)	261	SW Idaho
Danskin	Thermal (Natural Gas)	90	SW Idaho
Salmon	Thermal (Diesel)	5	E Idaho

Idaho Power has entered into a Settlement Agreement with the US Fish and Wildlife Service that provides for a study of Endangered Species Act (ESA) listed snails and their habitat. The objective of the research study is to determine the impact of peaking operations on the Bliss Rapids snail and the Idaho Spring snail. The study requires that Idaho Power operate the Bliss and Lower Salmon facilities following run-of-the-river flows during two of the next five years. Run-of-the-river operations will serve as the baseline, or control, for the study. The first year of the run-of-the-river operation is 2004.

General Hells Canyon Complex Operations

Idaho Power Company operates the Hells Canyon Complex to comply with the existing FERC license, as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements are the fall chinook plan voluntarily adopted by Idaho Power Company in 1991 to protect spawning and incubation of fall chinook below Hells Canyon Dam, a species that is listed as threatened under the Endangered Species Act, and the cooperative arrangement that Idaho Power Company had with federal interests between 1995 and 2001 to implement portions of the Federal Columbia River Power System (FCRPS) biological opinion flow augmentation program, a reasonable and prudent alternative (RPA) under the biological opinion intended to avoid jeopardy to ESA-listed anadromous species as a result of FCRPS operations below the Hells Canyon Complex.

Brownlee Reservoir is the only one of the three Hells Canyon Complex reservoirs – and Idaho Power Company's only reservoir – with significant water storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately one million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities – approximately 0.5 percent and 1.0 percent of Brownlee Reservoir's volume, respectively.

Brownlee Reservoir Seasonal Operations

Brownlee Reservoir is a multiple-use, year-round resource for Idaho Power Company and the Northwest. Although the primary purpose is to provide a stable power source, Brownlee Reservoir is also used to control flooding, to benefit fish and wildlife resources, and to benefit recreation.

Brownlee Dam is one of several Northwest dams that are coordinated to provide springtime flood control on the lower Columbia River. Between 1995 and 2001, Brownlee Reservoir, along with several other Northwest dams, was used to augment flows in the lower Snake River consistent with the FCRPS biological opinion. For flood control, Idaho Power Company operates the reservoir cooperatively with the U.S. Army Corps of Engineers (ACOE) North Pacific Division, according to Article 42 of the existing license.

After the flood-control requirements have been met in early summer, Idaho Power Company attempts to refill the reservoir to meet peak summer electricity demands and provide suitable habitat for spawning bass and crappie. The full reservoir also offers optimal recreational opportunities through the Fourth of July holiday.

The US Bureau of Reclamation (BOR) periodically releases water from BOR storage reservoirs in the upper Snake River in an effort to augment flows in the lower Snake River to help anadromous fish migrate past the FCRPS projects as part of the flow-augmentation implemented by the 2000 FCRPS biological opinions. From 1995 through the summer of 2001, Idaho Power Company cooperated with the BOR and other federal interests by shaping (or pre-releasing) water from Brownlee Reservoir (and later refilling the drafted reservoir space with water released by the BOR from the upper Snake River reservoirs) and by occasionally contributing water from Brownlee Reservoir to the flow-augmentation efforts.

In 1996, the Bonneville Power Administration (BPA) entered into an energy exchange agreement with Idaho Power Company to facilitate Idaho Power Company's cooperation with the FCRPS flow-augmentation RPA, and in recognition of the federal responsibility for the flow augmentation program. The BPA energy exchange agreement expired in April 2001 and although Idaho Power Company has expressed a willingness to continue to participate in the FCRPS flow-augmentation program through a similar arrangement, the BPA has chosen not to renew the agreement. For the summer of 2004, Idaho Power Company and the BPA have negotiated an agreement that provides the BPA an option to call on Idaho Power Company to release 100,000 acre-feet of water to augment Snake River flows during July. Idaho Power Company and the BPA continue to explore the possibility of a negotiated longer-term shaping agreement.

Brownlee Reservoir's releases are managed to maintain constant flows below Hells Canyon Dam in the fall. The constant flow requirements are based on the voluntary fall chinook plan that Idaho Power Company adopted in 1991, as well as the minimum flow required by Article 43 of the existing license. The constant flow helps ensure sufficient water levels to protect fall chinook spawning nests, or redds.

After the fall chinook spawn, Idaho Power Company attempts to have a full reservoir by the first week of December to meet winter peak demands. However, the fall spawning flows are maintained as the minimum flow below Hells Canyon Dam throughout the winter until the fall chinook fry emerge in the spring.

Maintaining constant flows to protect the fall Chinook spawning contributes to the need for additional resources during the fall months. The fall chinook operations result in lower reservoir elevations in Brownlee Reservoir and correspondingly lower the power production capability of the plant. The reduced power production may require Idaho Power Company to acquire power from other sources if the customer load cannot be met due to the loss of net head at the reservoir.

Federal Energy Regulatory Commission Relicensing Process

Idaho Power Company's hydroelectric facilities, with the exception of the Clear Lake and Thousand Springs plants, operate under federal licenses regulated by the Federal Energy Regulatory Commission (FERC). The process of relicensing Idaho Power's hydroelectric projects at the end of their initial 50-year license periods is well under way and the hydropower project relicensing schedule is shown in Table 4. A license renewal was granted by FERC in 1991 for the Twin Falls project.

Applications to relicense Idaho Power Company's three mid-Snake facilities (Upper Salmon, Lower Salmon, and Bliss) were submitted to FERC in December 1995. The application to relicense the Shoshone Falls project was filed in May 1997. The application to relicense the CJ Strike project was filed in November 1998. The FERC issued the licenses for Upper Salmon, Lower Salmon, Bliss, CJ Strike, and Shoshone Falls in August 2004.

The application to relicense the Upper and Lower Malad project was filed in July of 2002. The application to relicense the Hells Canyon Complex was filed in July 2003. The relicensing application for the Swan Falls project will be prepared and submitted in 2008.

Failure to relicense existing hydropower projects at a reasonable cost will create upward pressure on the current low rates for Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation, and enhancement (PM&E) imposed as a condition for relicensing. Idaho Power Company's goal throughout the relicensing process is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment. No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed has been assumed as part of the 2004 Integrated Resource Plan. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, then Idaho Power Company will

Table 4 Idaho Power Company Hydropower Project Relicensing Schedule

Project	FERC License Number	Nameplate Capacity (MW)	Current License Expires	File FERC License Application
Bliss	1975	75	Dec 1997	Dec 1995
Lower Salmon	2061	60	Dec 1997	Dec 1995
Upper Salmon	2777	34.5	Dec 1997	Dec 1995
Shoshone Falls	2778	12.5	May 1999	May 1997
CJ Strike	2055	82.8	Nov 2000	Nov 1998
Upper/Lower Malad	2726	21.8	July 2004	July 2002
Hells Canyon Complex	1971	1,166.9	July 2005	July 2003
Swan Falls	503	25	June 2010	June 2008

adjust future resource plans to reflect the need for additional capacity resources in order to maintain the existing level of reliability.

Environmental Analysis

The National Environmental Policy Act requires that the FERC perform an environmental assessment (EA) of each hydropower license application to determine whether federal action will significantly impact the quality of the natural environment. If so, then an environmental impact statement (EIS) must be prepared prior to granting a new license.

As part of the EA for Idaho Power's mid-Snake and Shoshone Falls applications, the FERC visited Idaho during July 1997 to receive public and agency input through scoping meetings. The FERC issued additional information requests (AIRs) in 1998 for the mid-Snake Projects. The FERC also visited Idaho to receive public and agency input at a scoping meeting held in September 1999. The FERC issued AIRs for the CJ Strike project in 1999. A draft EIS was issued on the mid-Snake projects in January 2002, and the FERC was in Idaho again in February 2002 to receive public and agency comment. The FERC issued a Final EIS document for the mid-Snake projects in July 2002 and the Final EIS for the CJ Strike project in October 2002. The FERC is currently in the process of preparing the draft EIS for the Hells Canyon Complex. The draft Hells Canyon EIS is expected to be released in 2005.

The FERC is currently developing an approach to a cumulative environmental analysis of the Snake River from Shoshone Falls through the Hells Canyon Complex. Once the analysis is complete, the FERC will consider recommendations from affected state and federal agencies and issue license orders for the affected projects, including required PM&E measures. New licenses are anticipated from the FERC for the Shoshone Falls, Upper Salmon, Lower Salmon, Bliss, and CJ Strike projects in late-2004. Opportunity for additional public comment on the draft EIS and final EIS for the Hells Canyon Complex will occur before the license order is issued. If a project's current license expires before a new license has been issued, annual operating licenses are issued by the FERC pending completion of the licensing process.

Hydroelectric Relicensing Uncertainties

Idaho Power Company is optimistic that the hydro project relicensing will be completed in a timely fashion. However, prior experience indicates that the relicensing process will probably result in an increase in the costs of generation from the relicensed projects. The increased costs are usually associated with the requirements imposed on the projects as a condition of relicensing. At this time, Idaho Power cannot reasonably estimate the impact of the relicensing process on the generating capability or operating costs of the relicensed projects. At the time of the 2006 IRP, Idaho Power will have better information regarding the power generation impacts of relicensing.

Baseload Thermal Resources

Jim Bridger

Idaho Power Company owns a one-third share of the Jim Bridger coal-fired plant located near Rock Springs, Wyoming. The plant consists of four nearly identical generating units. Idaho Power’s one-third share of the generating capacity of the Jim Bridger plant currently stands at 707 MW. After adjustment for scheduled maintenance periods and estimated forced outages and de-ratings, the annual energy-generating capability of Idaho Power’s share of the Jim Bridger plant is approximately 627 aMW.

Valmy

Idaho Power Company owns a 50 percent share, or approximately 261 MW of capacity of the 521 MW Valmy plant located east of Winnemucca, Nevada. The plant, which consists of one 254 MW unit and one 267 MW unit, is owned jointly with Sierra Pacific Power Company. After adjustment for scheduled maintenance periods and estimated forced outages and de-ratings, the annual energy-generating capability of Idaho Power’s share of the Valmy plant is approximately 231 aMW.

Boardman

Idaho Power owns a 10 percent share of the 552 MW coal-fired plant near Boardman, Oregon, operated by Portland General Electric Company. After adjustment for scheduled maintenance periods and estimated forced outages and de-ratings, the annual energy-generating capability of Idaho Power’s share of the Boardman plant is approximately 47 aMW.

Peaking Thermal Resources

Danskin

In addition to the three coal-fired steam-generating plants, Idaho Power owns and operates the Danskin Plant, a 90 MW natural gas-fired combustion turbine plant and the associated switchyard. The plant consists of two 45 MW Siemens-Westinghouse W251B12A combustion turbines. The 12-acre facility, constructed during the summer of 2001, is located northwest of Mountain Home, Idaho. The Danskin Plant operates as needed to support system load.

Bennett Mountain

During the spring and summer of 2003 Idaho Power Company conducted a competitive bidding process to acquire additional peaking generation. The 2003 Request for Proposals stated on page 4:

> PRODUCT
>
> A generating resource, located inside the Idaho Power Company control area, providing fully dispatchable, first call, non-recallable, physically delivered electrical capacity during June, July, August, November and December.
>
> QUANTITY
>
> Idaho Power Company anticipates acquiring between 85 and 200 MW of delivered energy under summer conditions (90°F) at the elevation of the site or sites identified in the proposal. Idaho Power Company may combine proposals to meet the 85 MW minimum capacity requirement.

Idaho Power Company selected Mountain View Power (now identified as TR^2) to construct a 162 MW Siemens-Westinghouse 501F simple cycle, natural gas fired, combustion turbine in Mountain Home, Idaho. The Idaho PUC issued a Certificate of Public Convenience and Necessity in Orders 29410 and 29422 in January 2004. The Bennett Mountain plant is expected to be constructed, fully commissioned, and on line by June 1, 2005 and will operate on an as-needed basis to support customer load.

Salmon Diesel

Idaho Power owns and operates two diesel generation units located at Salmon, Idaho. The Salmon diesels produce 5.5 MW and are primarily operated during emergency conditions.

PURPA (Public Utility Regulatory Policy Act)

In 1978 the US Congress passed the Public Utility Regulatory Policy Act (PURPA) requiring utilities such as Idaho Power to purchase the energy from Qualifying Facilities

(QF). Qualifying Facilities are privately owned small renewable generation projects or small cogeneration projects. The individual states were given the task of establishing the terms and conditions, including price, that each state's utilities would be required to pay as part of the PURPA agreements.

The Idaho Public Utilities Commission established two pricing concepts for PURPA projects. IPUC Order 29124, dated September 26, 2002 is the most recent IPUC order establishing the PURPA pricing concepts. The same order also made available 20-year contract terms. PURPA projects are split into two categories – small projects less than 10 MW and large projects 10 MW and over.

For projects greater than 10 MW there is a separate regulatory procedure to set the rates for each individual PURPA project. In general, the rates are based on Idaho Power Company's avoided cost as determined using a methodology outlined by the Idaho PUC.

For projects less than 10 MW, the IPUC is currently making use of a PURPA Published Avoided Cost model to create an individual price for each Idaho utility. The goal of the avoided-cost model is to create a price of the utility's additional resource that was avoided due to the addition of a PURPA project. Currently, it is assumed that a natural gas combined cycle turbine will be the selected resource that Idaho utilities would avoid and the avoided-cost model uses the cost of a combined cycle turbine in the avoided-cost estimates.

The avoided-cost model requires numerous estimated and forecasted inputs including expected plant life, estimated plant cost, expected year of plant construction, estimated fixed O&M costs, estimated variable O&M cost, estimated cost escalation rates, estimated fuel cost and associated escalation rate, and assumed plant heat rates. Of the inputs, fuel cost and the associated escalation rate have the most significant influence on the resulting price. Additionally, fuel cost and the associated escalation rate are the most volatile inputs and are the most difficult to estimate.

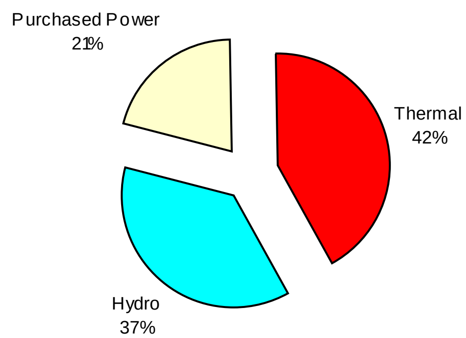
In IPUC Order 29124 the IPUC adopted using the Northwest Power and Conservation Council's medium natural gas price forecast for the fuel cost input and to update the PURPA Published Avoided Cost when new forecasts from the Northwest Power and Conservation Council become available. The Northwest Power and Conservation Council is expected to update the natural gas price forecast once a year.

IPUC Order 29391, dated December 5, 2003, established the PURPA Published Avoided Cost for Idaho Power to be 54.03 Mills per kWh (levelized rate, online in 2004, 20-year contract term).

Cogeneration and Small Power Producers (CSPP)

Idaho Power Company has over 70 contracts with independent power producers for over 200 aMW of nameplate capacity. Most of the projects are low-head hydro projects on various irrigation canals, cogeneration projects at industrial facilities, and various small renewable power projects. Idaho Power Company purchases approximately 100 MW of power from cogeneration and small power producers. Idaho Power Company is required to take the energy from these projects and Idaho Power Company does not consider the CSPP projects to be dispatchable. The Public Utility Regulatory Policy Act and various Idaho and

Figure 2 Idaho Power Company 2003 Energy Sources



Oregon PUC orders govern the rates, rules, and requirements for independent power producers.

Purchased Power

Idaho Power Company relies on regional markets to supply a significant portion of energy and capacity. Idaho Power Company's is especially dependent on the regional markets during peak periods. Reliance on regional markets has benefited Idaho Power customers during times of low prices and Idaho Power Company has a mechanism, the Power Cost Adjustment, to return these benefits to the customers. However, the reliance on regional markets can be costly in times of high prices such as during the summer of 2001. As part of the 2002 IRP process, the public, the Idaho Public Utilities Commission, and the Idaho legislature all suggested that the time had come for Idaho Power to reduce the reliance on regional market purchases. Greater planning reserve margins or the use of more conservative water planning criteria were suggested as methods requiring IPC to acquire more firm resources and reduce the likelihood of market purchases. Idaho Power Company adopted more conservative water planning criteria in the 2002 IRP.

Figure 2 shows the 2003 actual utilization of Idaho Power Company energy resources to serve customer load. As recently as 1998, the proportion of hydro generation exceeded 50 percent and purchased power was only 15 percent of the resource portfolio. Customer growth combined with below normal water lowered the proportion of hydro to 37 percent and increased purchased power to 21 percent of the portfolio in 2003.

Transmission Interconnections

Description

The Idaho Power transmission system is a key element serving the needs of the Idaho Power Company retail customers. The 230 kilovolt (kV) and higher voltage main grid system is essential for the delivery of bulk power supply. Figure 3 shows the principal grid elements of Idaho Power's high-voltage transmission system.

Capacity and Constraints

Idaho Power Company's transmission connections with regional utilities provide paths over which off-system purchases and sales are made. The transmission interconnections and the associated power transfer capacities are identified in Table 5. The capacity of a transmission path may be less than the sum of the individual circuit capacities. The difference is due to a number of factors, including load distribution, potential outage impacts, and surrounding system limitations. In addition to the restrictions on interconnection capacities, there are other internal transmission constraints that may limit IPC's ability to access specific energy markets. The internal transmission paths needed to import resources from other utilities and their respective potential constraints are shown in Figure 3 and Table 5.

Brownlee-East Path

The Brownlee-East transmission path is on the east side of the Northwest Interconnection shown in Table 5. Brownlee-East is comprised of the 230 kV and 138 kV lines east of the Brownlee/Oxbow/Quartz area and the Summer Lake-Midpoint 500 kV line. The constraint on the Brownlee-East transmission path is within Idaho Power's main transmission grid and located in the area between Brownlee and Boise on the west side of the system.

The Brownlee-East path is most likely to face summer constraints during normal to high water years. The constraints result from a combination of Hells Canyon Complex hydro generation flowing east into the Treasure Valley, concurrent with transmission wheeling obligations and purchases from the Pacific Northwest. Transmission wheeling obligations also affect southeast flow into and through Southern Idaho. Significant congestion affecting southeast energy transmission flow from the Pacific Northwest may also occur during the month of December. Restrictions on the Brownlee-East limit the amount of energy that Idaho Power Company can import from the Hells Canyon Project as well as limit the off-system purchases from the Pacific Northwest.

The Brownlee-East constraint is the primary restriction on imports of energy from the Pacific Northwest during normal and high water years. If new resources are sited west of this constraint, additional transmission capacity will be required to remove the existing Brownlee-East transmission constraint and deliver the energy from the additional resources to the Boise/Treasure Valley load area.

The new 10-mile transmission line between Brownlee and Oxbow identified as the Oxbow-Brownlee Number Two 230 kV line was designed to relieve the operating limitations associated with the coincident generation at Oxbow and Hells Canyon. The transmission upgrade increased the Brownlee-East capacity by approximately 100 MW, thereby increasing IPC's ability to import additional energy from the Pacific Northwest for native load use. The transmission upgrade was identified as part of the 2002 Integrated Resource Plan and has been completed and is now in service.

Oxbow-North Path

The Oxbow-North path is a part of the Northwest Interconnection and consists of the Hells Canyon-Brownlee and Lolo-Oxbow 230 kV double circuit line. The Oxbow-North path is most likely to face constraints during the summer months when high northwest-to-southeast energy flows and high hydro production levels coincide. Congestion on the Oxbow-North path also occurs during the winter months of November and December due to winter peak conditions throughout the region.

Northwest Path

The Northwest path consists of the 500 kV Summer Lake-Midpoint line, the three 230 kV lines between the Northwest and Brownlee, and the 115 kV interconnection at Harney. Deliveries of purchased power from the Pacific Northwest often flow over these lines. During low water conditions, total purchased power needs may exceed the capability of the Northwest Path. If new resources are sited west of this constraint, additional transmission capability will be needed to transmit the energy into the IPC control area.

Borah-West Path

The Borah-West transmission path is within Idaho Power's main grid transmission system located west of the Eastern Idaho, Utah Path C, Montana and Pacific (Wyoming) interconnections shown in Table 5. The Borah-West path consists of the 345 kV and 138 kV lines west of the Borah/Brady/Kinport area. The Borah-West path will be of increasing concern because the capacity of this path is fully utilized by existing wheeling obligations.

There is a strong probability that many of the generation alternatives considered in this IRP will be sited east of the Borah-West transmission path. Transmission improvements will be required to transfer this new generation through the Borah-West transmission path to serve load growth in the Boise area. Idaho Power Company has filed to increase the transfer capacity of the Borah-West Path. The first transmission project that would increase the east to west transmission capability by 150 MW is moving forward, and an additional 100 MW project is being considered. If both projects proceed, an additional 250 MW of transmission capability would be available to serve Idaho Power's native load requirements from the new generating resources identified in the Ten-Year Action Plan and the Near-Term Action plan discussed in Chapters 7 and 8. The appropriate transmission costs have been allocated to each of the new generating resources.

Midpoint-West Path

The Midpoint-West path is another transmission constraint that exists just west of the Midpoint area. The Midpoint-West constraint is slightly less restrictive than the Borah-West constraint at the present time. However, relatively small improvements on the Borah-West constraint may result in the Midpoint-West constraint limiting east to west transfers. Any significant improvement in the east to west transfers will probably require considerable upgrades to both the Borah-West and Midpoint-West paths. The transmission projects mentioned in the Borah-West section also include the necessary improvements to transfer the output of the proposed new generation resources through the Midpoint-West transmission path.

Figure 3 Idaho Power Company Transmission System

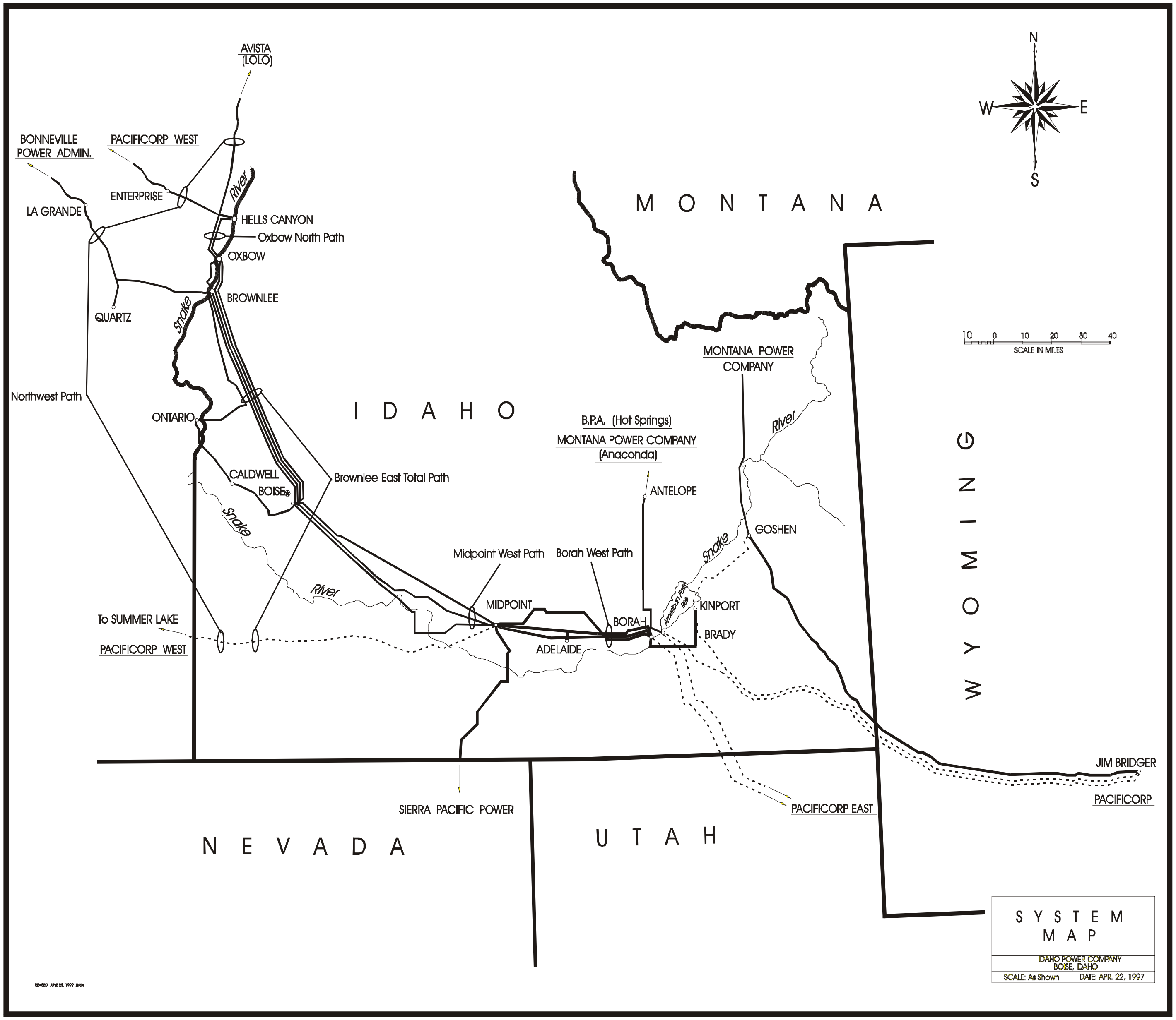


Table 5 Idaho Power Company Transmission Interconnections

Transmission Interconnections	Capacity to Idaho	Capacity from Idaho	Line or Transformer	Connects Idaho Power To
Northwest	1,090 to	2,400 MW	Oxbow-Lolo 230 kV	Washington Water Power
	1,200 MW		Midpoint-Summer Lake 500 kV	PacifiCorp (PPL Division)
			Hells Canyon-Enterprise 230 kV	PacifiCorp (PPL Division)
			Quartz Tap-LaGrande 230 kV	Bonneville Power Administration
			Hines-Harney 138/115 kV	Bonneville Power Administration
Sierra	262 MW	500 MW	Midpoint-Humboldt 345 kV	Sierra Pacific Power
Eastern Idaho[1]			Kinport-Goshen 345 kV	PacifiCorp (UPL Division)
			Bridger-Goshen 345 kV	PacifiCorp (UPL Division)
			Brady-Antelope 230 kV	PacifiCorp (UPL Division)
			Blackfoot-Goshen 161 kV	PacifiCorp (UPL Division)
Utah (Path C)[2]	775 to	830 to	Borah-Ben Lomond 345 kV	PacifiCorp (UPL Division)
	950 MW	870 MW	Brady-Treasureton 230 kV	PacifiCorp (UPL Division)
			American Falls-Malad 138 kV	PacifiCorp (UPL Division)
Montana[3]	79 MW	79 MW	Antelope-Anaconda 230 kV	NorthWestern Energy
	87 MW	87 MW	Jefferson-Dillon 161 kV	NorthWestern Energy
Pacific (Wyoming)	600 MW	600 MW	Jim Bridger 345/230kV	PacifiCorp (Wyoming Division)

Power Transfer Capacity for Idaho Power Company Interconnections

[1] The Idaho Power-PacifiCorp interconnection total capacities in Eastern Idaho and Utah include Jim Bridger resource integration.

[2] The Path C transmission path also includes the internal PacifiCorp Goshen-Grace 161 kV line.

[3] The direct Idaho Power-Montana Power schedule is through the Brady-Antelope 230kV line and through the Blackfoot-Goshen 161 kV line that are listed as an interconnection with PacifiCorp. As a result, Idaho-Montana and Idaho-Utah capacities are not independent.

Transmission Uncertainties

Open Access Transmission Service (FERC Order 888)

Since 1996 Idaho Power has been providing transmission service to qualified wholesale customers under its Open Access Transmission Tariff. Because of the geographic location of the Idaho Power transmission facilities, Idaho Power receives numerous requests for transmission capacity on the Idaho Power main grid transmission system to transport power between the Pacific Northwest and the Desert Southwest. Because the tariff is explicitly open access, Idaho Power cannot deny service to qualified wholesale customers when there is sufficient transmission capacity available to satisfy the customer's request. Also, the tariff provides that Idaho Power will construct additional transmission facilities to increase capacity if the party seeking to use the increased capacity pays the cost of adding the capacity. The consequence is that planning for Idaho Power's own use of its transmission system must take into account that there may be competing uses and that new wholesale customers have enforceable access rights.

Regional Transmission Organizations

In 1999 the FERC issued Order 2000 to encourage voluntary membership in regional transmission organizations (RTO). FERC Order 2000 precipitated considerable activity within the northwest focused on the decisions about whether to create an RTO and how an RTO should operate. Transmission restructuring activity is continuing and Idaho Power Company has been an active participant in efforts to determine an appropriate structure for provision of transmission service within the Pacific Northwest.

The essence of the RTO initiative was that all utilities owning high-voltage transmission facilities in the region would turn over operational control of their transmission systems to a single, independent regional operator. RTO formation would also establish organized markets for generation services such as the generation adjustments needed for managing transmission loading. While the proposed restructuring changes will not alter the physical capability of the transmission system, any operational changes will likely affect Idaho Power's use of its transmission system. The changes are intended to be beneficial, giving Idaho Power easier access to more efficient markets thus helping manage operation of the portfolio of resources that serve native load. However, significant uncertainties exist because the operating principals of a potential northwest RTO are largely undeveloped and controversial.

Western Electricity Coordinating Council Operating Transfer Capability Process

Since the large-scale transmission outages in the western US during the summer of 1996, transmission system capabilities have come under increasing scrutiny. The Western Electricity Coordinating Council (WECC) has reevaluated the transfer capability on many transmission lines. The net result of the WECC efforts to reevaluate the regional transfer capability is that a transmission operator no longer has the assurance that all of the historical line capability will be fully usable in the future. New interactions with other existing transmission paths, previously unidentified, can force reductions in existing transmission capability. Uncertainty surrounding the transfer capability presents real challenges to resource planning. Transmission system capability to handle multiple contingences was an issue that factored into the eastern US Interconnection outage of August 14, 2003. Recommendations to address the issues are not fully developed and there is considerable uncertainty regarding how any national recommendations will affect the WECC and the western US.

Off-System Purchases, Sales, and Load-Following Agreements

Idaho Power currently has three term off-system sales contracts. The three contracts were entered into in the late 1980s and early 1990s when Idaho Power had an energy and capacity surplus. The contracts, expiration dates, and average sales amounts are shown in Table 8 in Chapter 3.

The City of Weiser in SW Idaho has a full-requirements term sales contract with Idaho Power. Under the full-requirements contract, Idaho Power is responsible for supplying the entire load of the city. The City of Weiser is located entirely within Idaho Power's load-control area.

A term sales contract with Raft River Rural Electric Cooperative Inc. was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utilities Commission of Nevada. Raft River Rural Electric Cooperative Inc. is the electric distribution utility serving Idaho Power's former customers in the State of Nevada. Idaho Power sold the transmission and distribution facilities, along with the rights-of-way that serve about 1,250 customers in Northern Nevada and 90 customers in southern Owyhee County, to Raft River Rural Electric Cooperative Inc. The closing date of the transaction was April 2, 2001. The area sold to Raft River Rural Electric Cooperative Inc. is located entirely within Idaho Power's load-control area.

Idaho Power Company's third term sales contract is with the City of Colton in Southern California. In May 2002, Idaho Power Company notified the City of Colton that Idaho Power Company intended to terminate the contract with Colton at the end of May 2005. The contract termination required a three-year advance notification and could have been initiated by either party.

Idaho Power Company and Montana's NorthWestern Energy have negotiated a load-following agreement in which Idaho Power Company provides NorthWestern Energy with 30 MW of load-following service. The agreement includes provisions that allow Idaho Power Company to receive energy from NorthWestern Energy on the east side of the system during summer months. Idaho Power Company anticipates that the load following agreement with NorthWestern will be renewed throughout the IRP planning period. Idaho Power Company also has a load following agreement with NorthWestern for serving the Idaho Power Company load in Salmon, Idaho. Salmon, Idaho is located in the NorthWestern load control area.

Idaho Power Company has negotiated a purchase agreement with PPL Montana for 83 MW during heavy load hours in June, July, and August (heavy load hours are from hour ending 8:00 am to hour ending 11:00 pm, Monday through Saturday, Mountain Time). The purchase agreement expires in 2009, although Idaho Power Company assumes that the purchase agreement will be renewed.

Idaho Power Company has an exchange contract with the City of Anaheim, California. Idaho Power receives 10 MW energy during the months of April through August at Mona, Utah, and receives 20 MW of energy during November, 35 MW during December, and 25 MW during January. The November through January energy is delivered to Idaho Power Company at Mid-Columbia. Idaho Power Company delivers 20 MW of energy to the City of Anaheim during the months of October through March at the Valmy plant in Nevada. The contract is set to expire in March 2005 and renewal is uncertain.

Demand-Side Management

Idaho Power operates demand response, energy efficiency, market transformation, low income, public purpose and education programs with funding from a variety of sources. In response to IPUC Order 29026, issued in May 2002, Idaho Power initiated an energy efficiency tariff rider and receives approximately $2.7 million annually for demand-side management (DSM) programs. At the same time in 2002, an Energy Efficiency Advisory Group (EEAG) including customer, public, and private representatives was organized to provide advice and guidance to Idaho Power for administration of rider-funded programs. Idaho Power Company intends to file for a similar energy efficiency tariff rider with the Oregon PUC before the end of 2004.

The 2002 IRP indicated a need for near-term summer peak reduction. The primary focus of programs funded by the rider has been demand response, demand reduction and energy efficiency during summer peak periods.

Idaho Power is a participant of the Bonneville Power Administration Conservation and Renewable Energy Discount program devoting up to $525,000 per year to programs for lower-income residential customers. Additional funding for market transformation programs as well as low income and public purpose programs, are included in general operating expenses of the Company. Idaho Power completed a 2003–2005 Demand-Side Management Plan that outlines the management philosophy and direction for DSM.

In 2003, Idaho Power realized savings of 5,912 MWh and 189 kW of summer peak demand reduction from its energy efficiency and demand response programs. Savings from market transformation programs is reported below.

Demand Response Programs

Demand response is a term used broadly to refer to customer-chosen reductions or shifts in electricity use. In March 2003, the Idaho Public Utilities Commission issued Order 29207 and approved a request by Idaho Power to conduct a two-year Air Conditioning Cycling Pilot Program. The program enables Idaho Power to directly address summer peaking requirements by reducing some of the air conditioning load. Air conditioning load is one of the primary contributors to the summer peak.

Idaho Power's primary goal of the A/C Cycling Pilot Program is to assess the effectiveness of air conditioning controls for reducing peak load. Specific objectives include assessing the effect of control on customer satisfaction and comfort and retention, developing an analysis model for measuring peak load reduction, gaining operating experience in managing the program, and testing equipment.

Approximately 200 households participated in the summer of 2003 and 300 more households will be added in 2004. A final analysis of the A/C Cycling Program will be completed by the end of 2004.

In February 2004 Idaho Power filed an application with the Idaho PUC to conduct an Irrigation Peak Clipping Pilot program to be conducted during the summer of 2004. The Idaho PUC accepted the irrigation pilot and it is anticipated that a report analyzing the feasibility of a full-scale irrigation peak reduction program will be completed by the end of 2004.

Energy Efficiency and Peak Reduction Programs

Idaho Power works with the Energy Efficiency Advisory Group to select new DSM programs that consider resource needs and customer service characteristics. In 2003, Idaho Power completed a Compact Fluorescent Lamp Coupon Program, and launched four new full-scale DSM programs. The four DSM programs are:

1. Energy Efficient Manufactured Home Incentives *(January 2003)*
2. Manufactured Home Energy Checkups *(Late 2003)*
3. Industrial Efficiency Program *(October 2003)*
4. Irrigation Efficiency Program *(September 2003)*

Additionally, Idaho Power initiated or operated several DSM research pilot programs. The purposes of the pilot programs are to provide information to Idaho Power for assessing the viability of full-scale programs or to provide a trial period to fine-tune program parameters. The pilot programs include:

- Energy Star Homes Northwest “Quick Start”
- Trade In, Trade Up to Energy Star Pilot
- AirCare Plus Pilot
- Distribution Efficiency Initiative Pilot

Market Transformation Efforts

Idaho Power funds market transformation programs in the service territory through the Northwest Energy Efficiency Alliance (NEEA) and coordinating NEEA activities in Idaho. The Northwest Energy Efficiency Alliance is a regional group whose mission is to catalyze the Northwest marketplace to embrace energy-efficient products and services.

In Idaho, funding for the Idaho Power’s participation in the NEEA was authorized through 2004 by Order 28333 in Case IPC-E-99-13. The Oregon PUC approved the company’s expenditures for the NEEA for 2003.

Preliminary estimates reported by the NEEA indicate that Idaho Power’s share of regional market transformation kWh savings for 2003 is between 1.9 and 2.5 aMW. Idaho

Power relies on the NEEA to report the energy savings and other benefits of the NEEA regional portfolio of initiatives.

Low Income and Public Purpose Programs

Low-Income Weatherization Assistance

Low-Income Weatherization Assistance (LIWA) is a public-purpose program to make weatherization services more affordable for low-income customers. Authorized annual payments up to $1.2 million are made to local non-profit agencies participating in state-run weatherization programs in Idaho and Oregon to supplement federal funding. In Idaho, the provisions and payments are currently being negotiated with the community action agencies. In Oregon, all dwellings must be electrically heated and all measures must provide cost-effective electricity savings to be eligible for funding. Idaho Power typically contributes 50 percent of the cost for qualifying measures, plus a $75 administration fee, per dwelling. The program also funds weatherization of buildings occupied by tax-exempt organizations.

Oregon Commercial Audit Program

The Oregon Commercial Audit Program is a statutory program specifying that all commercial building customers be notified every year that information regarding energy-saving operations and maintenance measures is available and that commercial energy-audit services can be provided. The audit services are normally provided at no charge to the customer. Customers using more than 4,000 kWh per month may receive a more detailed audit but may be required to pay a portion of the cost.

Oregon Residential Weatherization

The Oregon Residential Weatherization Program is a statutory requirement program specifying annual notification to all residential customers informing them how to obtain energy audits and financing for energy conservation measures. To qualify for an Idaho Power audit or financing, customers must have electric space heat.

Small Project and Education Funds

Idaho Power, with support of the Energy Efficiency Advisory Group, set aside two funds – the Small Project Fund and the Education Fund. Each was initially funded with two percent of the Idaho DSM rider funding which results in approximately $54,000 available for each fund. The funds are designed to support research requests, educational opportunities and worthwhile small projects that are not eligible under other programs.

3. Planning Period Forecasts

Load Forecast

Future demand for electricity by customers in Idaho Power Company's service territory is defined by a series of six load forecasts, reflecting a range of load uncertainty resulting from differing economic growth and weather-related assumptions.

Table 6 summarizes three forecasts that represent Idaho Power's estimate of the boundaries of Idaho Power's annual total load growth over the planning period considering economic and demographic impacts on the load forecast – normal weather is assumed. There is a 90 percent probability that Idaho Power's load growth will exceed the Low Load Growth Forecast, a 50 percent probability of load growth exceeding the Expected Load Growth Forecast, and a 10 percent probability that load growth will exceed the High Load Growth Forecast. The projected 10-year average annual compound growth rate in the expected load forecast is 2.2 percent. Idaho Power believes that the Expected Load Growth Forecast is the most likely forecast and uses this forecast as the basis for further analysis of weather related uncertainties presented in Table 7.

Table 7 summarizes three forecasts that represent Idaho Power's estimate of Idaho Power's annual total load growth over the planning period considering normal, 70th percentile and 90th percentile weather impacts (explained in more detail below) on the Expected Load Growth Forecast (from Table 6). Idaho Power uses the 70th percentile forecast as the basis for resource planning. The 70th percentile forecast is referenced throughout the IRP.

Expected Load Forecast – Economic Impacts

The expected load forecast represents the most probable projection of service territory load growth during the planning period. The forecast for total load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix B, 2004 Sales and Load Forecast*. For example, the expected total load growth of 2.2 percent is comprised of residential load growth of 1.9 percent, commercial load growth of 3.2 percent, irrigation load growth of 0.2 percent, industrial load growth of 3.0 percent, and additional firm load growth of 1.9 percent.

Economic growth assumptions influence the individual customer-class forecasts. The number of service area households and various employment projections, along with customer consumption patterns, are used to form load projections. Economic growth information for Idaho and its counties can be found in *Appendix A, 2004 Economic Forecast*.

The number of households in the State of Idaho is projected to grow at an annual average rate of 1.7 percent during the 10-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area household projections are derived from individual county household forecasts. Growth in the number of households within the Idaho Power service territory, combined with estimated consumption per household, results in the previously mentioned 1.9 percent residential load growth rate.

Table 6 Load Forecast Probability Boundaries *(Average Megawatts, aMW)*

Year	Low Load Growth Forecast	Expected Load Growth Forecast	High Load Growth Forecast
2004	1,640	1,678	1,727
2005	1,662	1,720	1,787
2006	1,687	1,760	1,845
2007	1,716	1,803	1,902
2008	1,747	1,846	1,960
2009	1,777	1,889	2,016
2010	1,807	1,930	2,071
2011	1,836	1,970	2,124
2012	1,864	2,008	2,176
2013	1,893	2,049	2,228
Growth Rate *(2004 through 2013)*	1.6%	2.2%	2.9%

The number of households in the Idaho Power Company service territory is expected to increase from around 320,500 at the end of 2003 to nearly 383,600 by the end of the planning period in 2013.

Expected Load Forecast – Weather Impacts

The expected case load forecast assumes median temperatures and median precipitation meaning that there is a 50 percent chance that loads will be higher or lower than the expected case load forecast due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier-than-median precipitation.

Since actual customer loads can vary significantly depending upon weather conditions, two alternative scenarios were considered that address load variability due to weather. Idaho Power Company has generated load forecasts for 70th percentile weather and 90th percentile weather. Seventieth percentile weather means that in seven out of 10 years, the load is expected to be less than the forecast and in three out of 10 years, the load is expected to exceed the forecast. Ninetieth percentile load has a similar definition.

Cold winter days create high heating load. Hot, dry summers create both high-cooling and high-irrigation loads. Heating degree-days, cooling degree-days, and growing degree-days are used to quantify the weather and estimate a load forecast. In the winter, maximum load occurs with the highest recorded levels of heating degree-days (HDD). In the summer, maximum load occurs with highest recorded levels of cooling and growing degree-days (CDD and GDD).

For example, at the Boise Weather Service Office, the median number of HDD in December over the 1948–2003 time period is 1,040 HDD. The coldest December over the same time period was December 1985 when there were 1,619 HDD recorded at Boise.

For December, the 70th percentile HDD is 1,068 HDD. The 70th percentile value is likely to be exceeded in three out of 10 years on average. The 90th percentile HDD is 1,194 HDD and is likely to be exceeded in one out of 10 years on average. Percentile

Table 7 Range of Total Load Growth Forecasts in Average Megawatts

Year	Median	70th Percentile	90th Percentile
2004	1,678	1,720	1,788
2005	1,720	1,762	1,831
2006	1,760	1,803	1,873
2007	1,803	1,845	1,917
2008	1,846	1,889	1,962
2009	1,889	1,932	2,006
2010	1,930	1,974	2,048
2011	1,970	2,014	2,090
2012	2,008	2,053	2,130
2013	2,049	2,094	2,171
Growth Rate *(2004 through 2013)*	2.2%	2.2%	2.2%

calculations were used in each month throughout the year for the weather-sensitive customer classes – residential, commercial, and irrigation – to forecast load.

In the 70th percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70th percentile of HDD in winter and at the 70th percentile of CDD in the summer. In the 70th percentile irrigation load forecast, GDD were assumed at the 70th percentile and precipitation was assumed to be at the 70th percentile, reflecting weather that is both hotter and drier than median weather. The 90th percentile irrigation load forecast was similarly constructed using weather values measured at the 90th percentile.

Idaho Power loads are highly dependent upon weather. The three scenarios allow careful examination of load variability and how the load variability may impact resource requirements. It is important to understand that the probabilities associated with the load forecasts apply to any given month and that an extreme month may not necessarily be followed by another extreme month. In fact, a typical year likely contains some extreme months as well as some mild months.

Weather conditions are the primary factor affecting the load forecast on the weekly, monthly, and seasonal time horizon. Economic and demographic conditions affect the load forecast in the long-term horizon.

Astaris

The Astaris elemental phosphorous plant, located on the western edge of Pocatello, Idaho, ceased large-scale production in mid-December of 2001. Four months later, in April 2002, the special contract between Astaris and Idaho Power Company was terminated. Since then, Astaris (now FMC Corporation) has been billed for electric service as a Schedule 19 customer. Therefore, Astaris load since May 1, 2002 as a special contract customer is zero. Astaris had been the Company's largest individual customer and in some past years had averaged nearly 200 average megawatts of load. Today, the Astaris load is less than 4 MW.

Table 8 Firm Sales Contracts

Contract	Expiration	2004 Average Load
City of Weiser (Idaho)	December, 31 2004	6 aMW
City of Colton (California)	May 31, 2005	3 aMW
Raft River Rural Electric Cooperative (Nevada)	September 30, 2006	6 aMW
Total Firm Sales		*15 aMW*

Micron Technology

Micron Technology has replaced Astaris as the Company's largest individual customer. In the 2004 IRP forecast, electricity sales to Micron Technology are expected to steadily rise throughout the forecast period. The primary driver of long-term electricity sales growth at Micron Technology is employment growth in the Electronic Equipment sector as provided by the 2004 Economic Forecast. The Micron contract allows for capacity expansion up to 100 megawatts. Presently the Micron load is around 80 aMW.

Simplot Fertilizer

In August of 2002, Simplot Fertilizer closed its ammonia production facility near Pocatello. The ammonia plant represented about 11 MW, or about one-third of the entire Simplot load. The ammonia is now being purchased on contract from an outside supplier. Offsetting the decline is the equipment required to unload and store the ammonia, which consists of an additional 3 or 4 MW. The total load at Simplot Fertilizer is around 16 aMW and the peak demand is around 25 MW.

Idaho National Engineering and Environmental Laboratory

The Idaho National Engineering and Environmental Laboratory (INEEL) is the Department of Energy research facility located in Eastern Idaho northwest of Pocatello. The INEEL is operated for the Department of Energy by Bechtel BWXT Idaho, LLC. Members of the LLC are Bechtel National Inc., BWX Technologies Inc., and a consortium of eight regional universities. The laboratory employs about 8,000 people. Historically, INEEL has operated several experimental nuclear reactors and generated a significant portion of its energy needs. Today, the laboratory is a special contract customer of Idaho Power Company with an average load of around 15 aMW. Peak demand can be nearly 35 MW.

Firm Sales Contracts

Idaho Power currently has three firm sales contracts. The contracts, expiration dates, and 2004 average load are shown in Table 8.

Although Table 8 shows expiration dates for the City of Weiser and the Raft River Rural Electric Cooperative contracts, it is anticipated that both of the contracts will be renewed with updated provisions prior to the expiration date. Idaho Power will continue to evaluate the value of firm sales contracts, but with the exceptions of the City of Weiser and Raft River Rural Electric Cooperative Inc., Idaho Power has not included the renewal of any term off-system sales contracts in its load projections.

Hydro Forecast

Hydrologic Baseflow

The representative hydrologic conditions used for analysis within the 2004 IRP (the 50^{th}, 70^{th}, and 90^{th} percentiles) are based on a computed hydrologic record for the Snake River Basin dating back to 1928. The historical record has been developed by the Idaho Department of Water Resources (IDWR) for the purpose of obtaining a hydrologic period of record of sufficient length to validate probability-based decisions. For example, a median (50^{th} percentile) hydrologic condition based on a 75-year hydrologic period of record is generally considered more representative of true median conditions than the condition derived from a 50-year period of record. Table 9 shows the April through July Brownlee inflow history since 1993. The data reported in Table 9 indicate that in four of the recent years the Brownlee inflow was less than the 70^{th} percentile planning criterion, and in two of those years, 1994 and 2001, the flows were less than the 90^{th} percentile planning criterion.

Water management facilities, irrigation facilities, and operations in the Snake River Basin changed greatly during the 20^{th} century. Therefore, for a hydrologic record to be meaningful from a planning perspective, the hydrologic record should reflect the current level of development in the Basin. The process followed by IDWR in developing the hydrologic record involves modifying the actual historical record to account for development, present baseflow, current system operations and existing facilities. For example, prior to the late 1940s the primary mechanism for irrigation was flood surface water irrigation. As the agricultural surface water system, including reservoirs for storage, was developed from the late 1800s to its height in the 1930s and 1940s, more water was diverted leaving less water in the Snake River. Over the past 50 years there has been significant conversion from flood irrigation to sprinkler irrigation, and from surface supplied irrigation to groundwater supplied irrigation. There has also been a significant additional amount of groundwater irrigated land put into production over the past 50 years resulting in reduced spring fed contributions to the river. As a result of these changes over the years, the natural flow hydrograph has been altered. The timing and volume of the natural flow, in the river and from the springs, has changed. The changes are built into the historical record to reflect today's system. IPC uses the IDWR standardized hydrologic record in the hydro generation modeling performed for the Company's Integrated Resource Plan.

Table 9 Recent Brownlee Inflow History

Year	April - July Brownlee Inflow (MAF)	Rank	Worse than 70th Percentile Planning Criterion	Worse than 90th Percentile Planning Criterion
1993	6.1	0.40		
1994	2.6	0.93	X	X
1995	6.8	0.33		
1996	8.4	0.16		
1997	9.9	0.07		
1998	9.0	0.13		
1999	8.0	0.20		
2000	4.4	0.60		
2001	2.4	0.95	X	X
2002	3.2	0.81	X	
2003	3.6	0.76	X	

Part of the process by which the historical record is standardized involves adjusting the actual flows to a level of baseflow that is representative of the conditions existing today. Baseflow is defined as that portion of streamflow derived primarily from groundwater seepage into the stream channel. Observed records suggest that baseflow in the Snake River, particularly between the Company's Twin Falls and Swan Falls projects, has been in decline for several decades. The yearly average flow measured below Swan Falls declined at an average rate of 43 cubic feet per second (cfs) per year (43 cfs/year) during the period 1960-2003, and observed streamflow gains between Twin Falls and Lower Salmon Falls, which are largely attributed to baseflow contribution, declined at a rate of 27 cfs/year over the same period. A decrease of 43 cfs per year represents the loss of over 31,000 acre-feet of water per year. The streamflow decline of 43 cfs per year represents a hydro generation loss of approximately 140 aMW in 2003 as compared to 1960. If the trend continues, the reduction in hydro generation may reach 170 aMW by 2013.

The observed decline, which continues today, is due to consumptive groundwater withdrawals and is influenced by extended drought conditions. IDWR has not updated the standardized hydrologic record since 1992. The implication is that the computed hydrologic record, on which the representative hydrologic conditions are based, overstates the level of baseflow existing today and expected in the future. Consequently, the representative hydrologic conditions used for the Idaho Power Company 2004 Integrated Resource Plan may also be overstated.

IDWR is in the process of updating the computed hydrologic record. It is anticipated that the updated record will more accurately reflect the decreased baseflow existing in the system today and expected in the future. However, depending on the extent to which baseflow continues to decline and the accuracy of the updated record, it will be necessary in the future to adjust the level of needed generation to account for this reduction in flow.

Generation Forecast

The generation forecast includes existing and committed resources. The output from the two committed resources, Bennett Mountain (162 MW available in 2005) and the Shoshone Falls upgrade (60 MW available in 2008) are included in the Idaho Power Company generation forecast.

Scheduled and forced outages are incorporated in the forecast using historical data. Idaho Power Company used planned maintenance and traditional maintenance schedules to estimate scheduled outages. Forced outages were estimated using observed forced outage rates at the various facilities randomly assigned throughout the planning period. The hydro facility generation is directly related to the hydro forecast discussed earlier.

Transmission Forecast

Transmission constraints are an important factor in Idaho Power Company's ability to reliably serve peak load conditions. Off-system market purchases are the last resort the Company employs when its own generating resources and firm purchases are inadequate to meet the load requirements. The transmission constraints on the IPCo system limit the Company's ability to employ off-system market purchases for many timeframes and system conditions.

The transmission analysis requires hourly forecasts for the entire 10-year planning period for loads and generation levels on the IPCo system. The hourly transmission analysis is used to quantify the magnitude of off-system market purchases that may be required to serve the load, and determine if there will be adequate transmission capacity available to deliver the off-system purchases to the load centers.

From the hourly load and generation forecasts, a determination can be made regarding the need for, and magnitude of, off-system market purchases needed to serve the loads. The projected off-system market purchases are summed with all other committed transmission obligations to determine if the resulting transmission load will exceed the operational limits of the IPCo transmission constraints.

The analysis assumes all off-system market purchases will come from the Pacific Northwest. Historically, during Idaho Power Company peak load periods, off-system market purchases from other areas have often times proven to be unavailable or very expensive. Many of the utilities to the east and south of Idaho Power Company also experience a summer peak, and the weather conditions that drive the summer peak are often similar across the Intermountain and Rocky Mountain West. Because Idaho Power has not been able to rely on the Rocky Mountain and Intermountain power markets for market purchases, Idaho Power Company believes that it would not be prudent to rely on imports from the Rocky Mountain region for planning purposes.

Three different hydro generation/load scenarios are considered in the transmission analysis:

1. Median water/median load
2. Seventieth percentile water and 70th percentile load
3. Ninetieth percentile water and 70th percentile load

The results of the 90th percentile water and 70th percentile load case are given the most weight in the transmission adequacy analysis, since using the transmission system to bring in off-system market purchases is the last option available when system conditions are worse than anticipated.

One difficulty with transmission planning is that while transmission resources are owned by a specific entity, the transmission resources can be utilized by other parties due to the open access requirements. Idaho Power Company must reserve the use of its own transmission resources under open access as well. Often, the Snake River spring water forecasts are unknown until May or June. By that time it is too late to acquire transmission with a firm reservation. An additional concern is that the peak time for Idaho Power Company is July, which coincides with high energy demand in the markets to the east and south of the Idaho Power Company service territory. Idaho Power Company has experienced difficulty purchasing energy and acquiring transmission from the south and east during the July peak period. Based on these concerns, Idaho Power Company believes that the 90th percentile planning criteria are appropriate for the critical transmission resources.

The 90th percentile planning criteria mean that there is a one-in-ten chance that Idaho Power Company will face more drastic measures such as curtailing load if attempts to acquire energy and transmission access from the east and south markets are unsuccessful. Unusual weather conditions and failures in the California energy market led to extremely high energy prices throughout the western US during the summer of 2001. Idaho consumers directly felt the effects of the high prices and Idaho Power initiated an irrigation curtailment program in response.

The results of the 90th percentile water and 70th percentile load scenario were used to establish a capacity target for planning purposes. The capacity target identifies the amount of internal generation or DSM that must be added to the Idaho Power Company system to avoid transmission overloads.

Fuel Price Forecasts

Coal Price Forecast

The IRP expected coal price forecast is an average of Idaho Power's spot coal forecasts for its Valmy and Boardman thermal plants. The plant forecasts are created using current coal and rail transportation market information and then escalated based on the 2003 Department of Labor Bureau of Labor Statistics forecasts along with the Global Insight 2003 US Power Outlook report. The resulting costs in dollars per MMBtu represent the delivered cost of coal, including rail costs, coal costs, and use taxes.

Natural Gas Price Forecast

Idaho Power Company does not directly forecast natural gas prices; instead Idaho Power Company combines industry forecasts. The IRP expected gas price forecast is derived from public and private source forecasts including IGI Resources, NYMEX, PIRA, CERA, EIA, NWPPC, and US Power Outlook. All source forecasts are converted to nominal dollars and converted to a Sumas equivalent dollars per MMBtu. Each source forecast is given a weight and included in a total weighted average to forecast Sumas dollars per MMBtu. Transportation costs are then added to the weighted average price to develop a delivered Sumas price in dollars per MMBtu. The transportation costs include Northwest Pipeline fixed and volumetric charges as well as fuel gas.

The IRP high and low Henry Hub equivalent gas price forecasts were derived using a private source forecast. The private forecast bracketed a reference case with both a high and a low gas value. The annual differential was calculated for 2004–2018 and the 2004–2018 trend was used to forecast prices through 2034. The forecasted annual differential was then applied to the IPCo Henry Hub equivalent gas forecast to generate the high and low forecast values.

Fuel forecast values are included in the *Technical Appendix*.

4. Future Requirements

Beginning with the 2002 IRP, Idaho Power specified a resource adequacy criterion requiring that new resources be acquired at the time that the resources are needed to meet forecast energy growth, assuming a water condition at the 70th percentile for hydroelectric generation.

The 70th percentile means that Idaho Power plans generation based on streamflows that occur in seven out of ten years on average. Streamflow conditions are expected to be worse than the planning criteria 30 percent of the time.

In the past, the Western Electricity Coordinating Council resource planning reserve required Idaho Power to maintain 330 MW of reserves above the forecast peak load to cover its worst single planning contingency which was defined to be an unexpected loss equal to Idaho power’s share of two Bridger generation units. At present, WECC has dropped the planning reserve requirements. The National Electric Reliability Council recently approved measures requiring the WECC to reinstate some form of planning reserve requirements. Idaho Power will continue meeting the historical WECC planning reserve requirements under any planning scenario until replacement planning requirements are in place. Idaho Power’s current peak load is approximately 3,000 MW, meaning that the 330 MW reserve translates into a reserve margin of approximately 11 percent.

A 70th percentile monthly water planning differentiates Idaho Power from other Northwest utilities, which typically plan resources based upon having annual generating capability sufficient to meet forecast annual energy requirements under critical water conditions. Critical water conditions are generally defined to be the worst, or nearly worst, annual water conditions based on historical streamflow records. A summary of other Northwest utility planning criteria is included in the *Technical Appendix*.

Using the 70th percentile water-planning criterion produces surpluses whenever streamflows are greater than the 70th percentile. Temporary off-system sales of surplus energy and capacity provide additional revenue and reduce the costs to IPC customers. During months when Idaho Power faces an energy or capacity deficit because of low streamflow, excessive demand, or for any other reason, Idaho Power plans to purchase off-system energy and capacity on a short-term basis to meet system requirements.

Low-water (90th percentile) scenarios have been evaluated and included in the 2004 Integrated Resource Plan to demonstrate the viability of IPC’s plan to serve peak and energy loads under low-water conditions. The evaluations include consideration of IPC’s transmission capability at times of lower streamflows.

The 90th percentile water and 70th percentile load conditions are used in the transmission analysis to establish the timing and magnitude of future peaking resources.

Impact of Salmon Recovery Program on Resource Adequacy

The December 1994 Amendments to the Northwest Power Planning Council’s fish and wildlife program and the biological opinions issued under the Endangered Species Act (ESA) for the four lower Snake River federal hydroelectric projects call for 427,000 acre-feet of water to be acquired by the federal government from willing lessors upstream of Brownlee

Reservoir. The acquired water is then to be released during the spring and summer months to assist ESA-listed juvenile salmonids (spring, summer, fall Chinook and steelhead) migrating past the four federal hydroelectric projects on the lower Snake River. In the past, water releases from Idaho Power's hydroelectric generating plants have been modified to cooperate with the federal efforts. Idaho Power also adjusts flows in the late fall of each year to assist with the spawning of fall Chinook below the Hells Canyon Complex.

Because of the practical, physical, and legal constraints that federal interests must deal with in moving 427,000 acre-feet of water out of Idaho, Idaho Power has pre-released, or shaped, a portion of the acquired water with water from Brownlee Reservoir and later refilled the reservoir with water leased under the federal program. At times, Idaho Power has also contributed water from Brownlee to assist with the federal efforts to improve salmonid migration past the lower Snake federal projects.

Water Planning Criteria for Resource Adequacy

Idaho Power Company has an obligation to serve customer loads regardless of the water conditions that may occur. In the past, when water conditions were at low streamflow levels, IPC relied on market purchases to serve customer loads. Historically, the Idaho Power Company plan was to acquire or construct resources that would eliminate expected energy deficiencies in every month of the forecast period whenever median or better water conditions existed, recognizing that when water levels were below median, Idaho Power Company would rely on market purchases to meet any deficits. When water levels were greater than median, Idaho Power Company would sell the surplus power in the regional markets.

In connection with the market price movements to historical highs during the energy crisis of 2000 and 2001, Idaho Power Company reevaluated the planning criteria as part of the 2002 IRP. The public, the Idaho Public Utilities Commission, and the Idaho legislature all suggested that Idaho Power placed too great a reliance on market purchases based upon the IRP planning criteria. Greater planning reserve margins or the use of more conservative water planning criteria were suggested as methods requiring Idaho Power to acquire more firm resources and reduce the likelihood of market purchases.

Due to the public input to the planning process, Idaho Power Company developed a resource plan based upon a lower-than-median level of water. Beginning with the 2002 resource plan, Idaho Power Company began using the 70th percentile water conditions and load conditions for resource planning. The 2004 Integrated Resource Plan is the second resource plan wherein Idaho Power Company is using the 70th percentile water and load conditions.

Historically, Idaho Power has been able to reasonably plan for the use of short-term power purchases to meet temporary water-related generation deficiencies on its own system. Short-term power purchases have been successful because Idaho Power customers typically have summer peaking requirements while the other utilities in the Pacific Northwest region have winter peaking requirements

Although Idaho Power has transmission interconnections to the Southwest, the Northwest market is the preferred source of purchased power. The Northwest market has a large number of participants, high transaction volume, and is very liquid. The accessible power markets south and east of Idaho Power's system tend to be smaller, less liquid, and have greater transmission distances. The markets south and east of the Idaho Power system can be very limited during summer peak conditions.

Under the low water and high-load conditions, projected peak-hour loads are likely to cause peak-hour transmission overloads from the Pacific Northwest and the transmission overloads may present significant difficulties as early as the summer of 2007 (transmission adequacy is discussed later in this chapter). Based on the low-water analyses, Idaho Power Company believes that it will be difficult to acquire and deliver short-term resources from the Pacific Northwest in amounts sufficient to satisfy peak-hour deficiencies during low-water conditions.

Recent experiences indicate that, even when Northwest power is available, the short-term prices can be quite high and volatile. The price risk has led to the development of the Risk Management Policy discussed in the Introduction. The Risk Management Policy represents collaboration of Idaho Power, the IPUC staff, and interested customers in Commission Case IPC-E-01-16.

The primary uncertainties associated with planned short-term power purchases are the availability of adequate Northwest to Idaho transmission capacity to allow imports at the times when needed, and uncertainty concerning the market prices of the purchases.

Planning Scenarios

70th Percentile Water, 70th Percentile Load (Energy)

The main planning scenario for determining the need for energy resources assumes 70th percentile water and 70th percentile load conditions. In purely statistical terms, if the two probabilities are independent, then one of the two conditions, either poor water conditions or high load conditions, can be expected in about half of the years (0.7 * 0.7 = 0.49).

During the summer peak periods, low water conditions are more problematic than are high load conditions. The variability around the summer peak load is considerably less than the variability associated with water conditions. For example, April through July Brownlee inflow can range from under 2 million acre-feet to nearly 13 million acre-feet. The summer high temperature ranges from 98 to 111, meaning that hot summer temperatures are more certain than are water conditions. Low water conditions are likely to be the more significant planning factor.

Idaho Power Company makes resource planning decisions based on the 70th percentile forecasts. Alternative forecasts are included in the 2004 Integrated Resource Plan to help understand the boundaries of the main forecast. Idaho Power presents a 90th percentile hydrological forecast to suggest what might happen in extremely dry years. A median water and median load forecast is also included. The primary purpose for including median forecast is to allow a historical comparison of the 2004 Integrated Resource Plan with earlier Idaho Power Company resource plans. The median forecast is no longer used for resource planning, although the median forecast is used to set retail rates and avoided-cost rates during regulatory proceedings.

Figure 4 indicates that when 70th percentile water and 70th percentile load conditions occur, energy deficiencies begin in December 2009. The initial deficiencies are approximately 6 aMW and increase to approximately 163 aMW by December 2013. Summer deficiencies in July are expected to increase from approximately 7 aMW in 2004 to approximately 340 aMW in 2011.

70th Percentile Water, 70th Percentile Load (Peak)

Figure 5 provides the peak load deficiencies corresponding to the 70th percentile water and 70th percentile load scenario, which is primarily used to identify the need for energy resource acquisition. With 70th percentile water and 70th percentile load conditions, summer peak-hour energy deficiencies occur starting in June 2004 at 280 MW and increase to 976 MW in July 2013. Winter peak-hour deficiencies occur beginning in December 2004 at 86 MW and increase to 463 MW in December 2013. By 2008, peak-hour deficiencies occur in seven months – May through September, and November and December. The peak-hour deficiencies continue to increase throughout the planning period reaching a maximum of nearly 1,000 MW in July 2013.

90th Percentile Water, 70th Percentile Load (Energy)

Figure 6 illustrates that under the 90th percentile water, 70th percentile load scenario, summer energy deficiencies occur in all years starting in May 2004, with 10 aMW, and increasing to 529 aMW in July 2013. Winter energy deficiencies occur in most years starting in December 2004 at 55 aMW and increasing to 261 aMW by December 2013. By 2008, deficiencies occur in 7 of 12 months; by 2011, all months are deficit under 90th percentile water conditions.

90th Percentile Water, 70th Percentile Load (Peak)

The primary scenario for determining the need for peak-hour, or capacity, resources is the 90th percentile water and 70th percentile load scenario. The pattern of deficiencies for the 90th percentile water, 70th percentile load scenario is similar to the pattern of deficiencies for the 70th percentile water, 70th percentile load scenario, only more severe. Peak-hour deficiencies in the peak months are typically 40 to 60 MW greater because of changes in water conditions. Monthly peak-hour surpluses and deficiencies for the 90th percentile water, 70th percentile load growth are shown in Figure 7.

Figure 4 Monthly Energy Surplus / Deficiency
70th Percentile Water and Load, Existing and Committed Resources

Figure 5 Monthly Peak-hour Surplus / Deficiency
70th Percentile Water and Load, Existing and Committed Resources

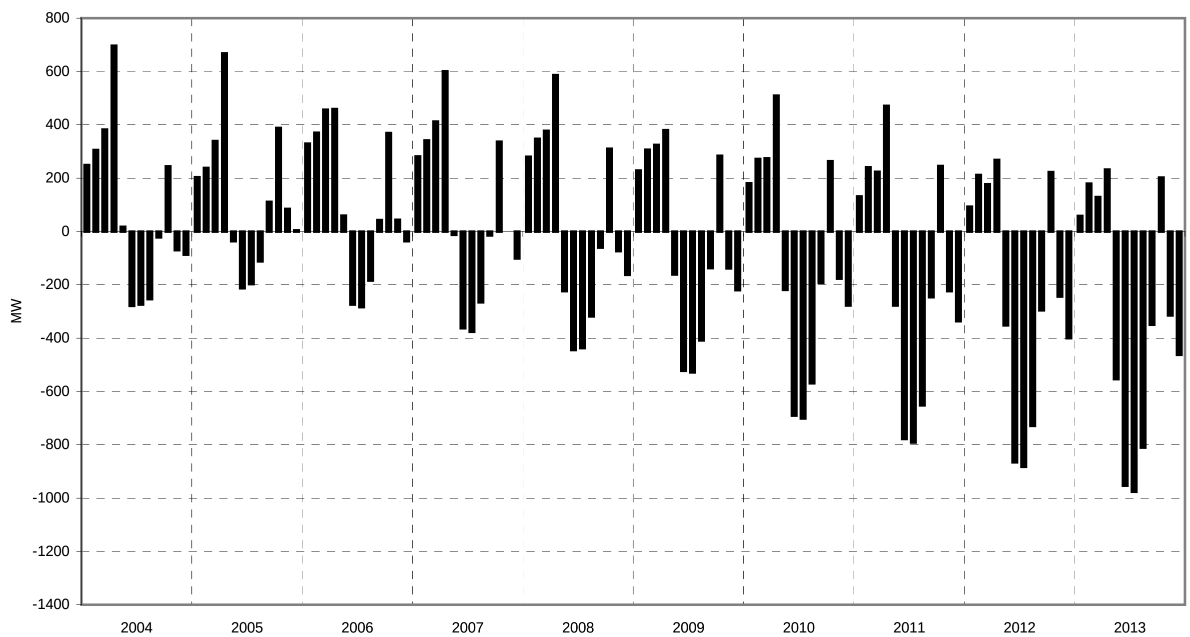


Figure 6 Monthly Energy Surplus / Deficiency
90th Percentile Water, 70th Percentile Load, Existing and Committed Resources

Figure 7 Monthly Peak-hour Surplus / Deficiency
90th Percentile Water, 70th Percentile Load, Existing and Committed Resources

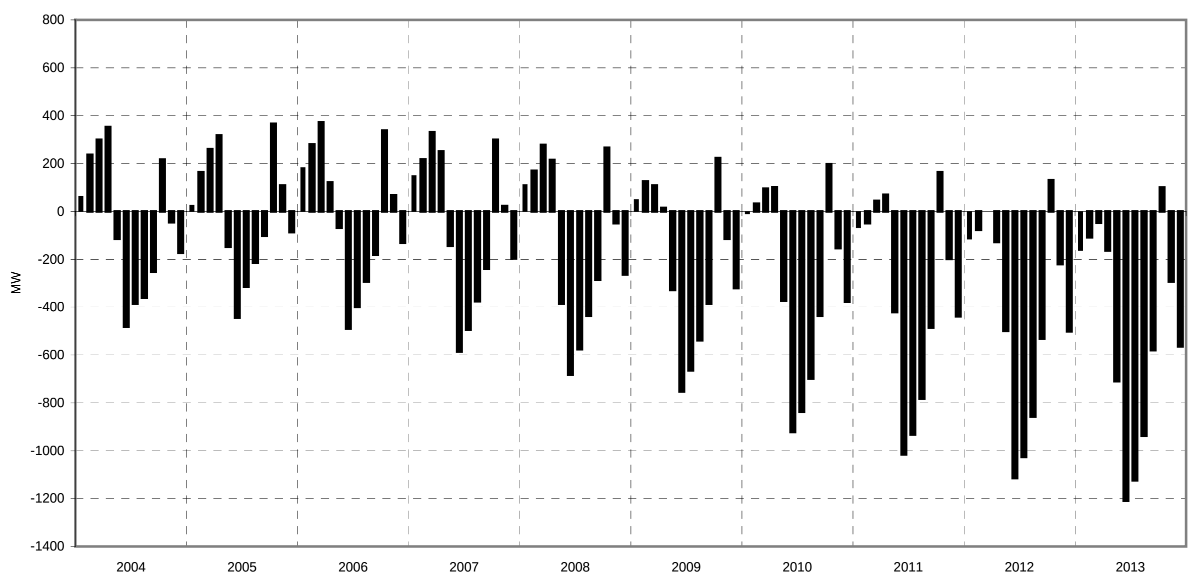


Figure 8 Monthly Energy Surplus / Deficiency
Median Water, Median Load, Existing and Committed Resources

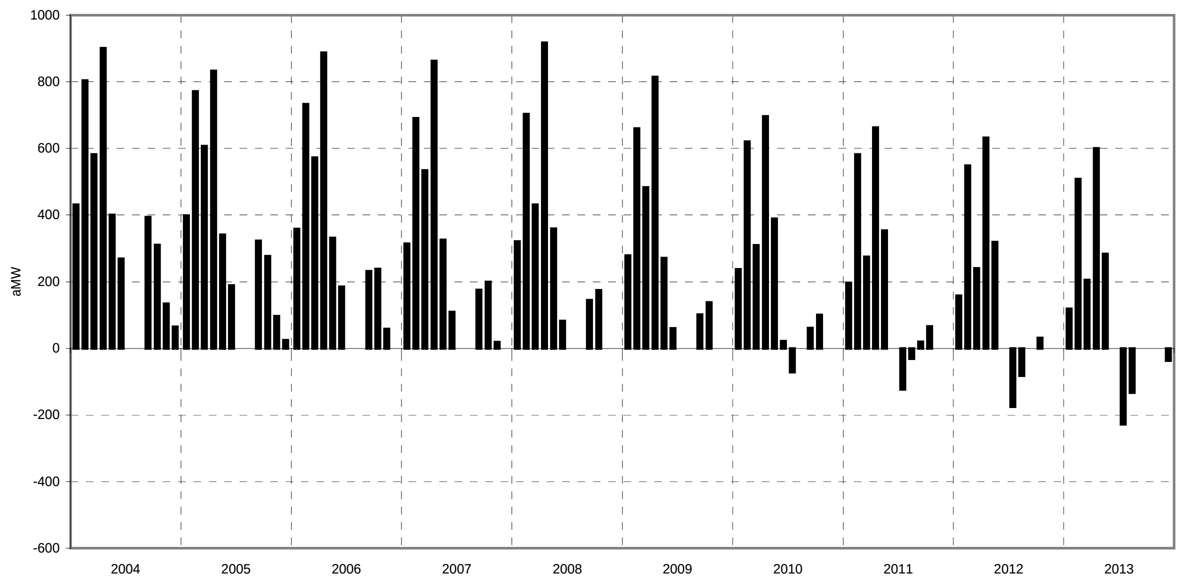
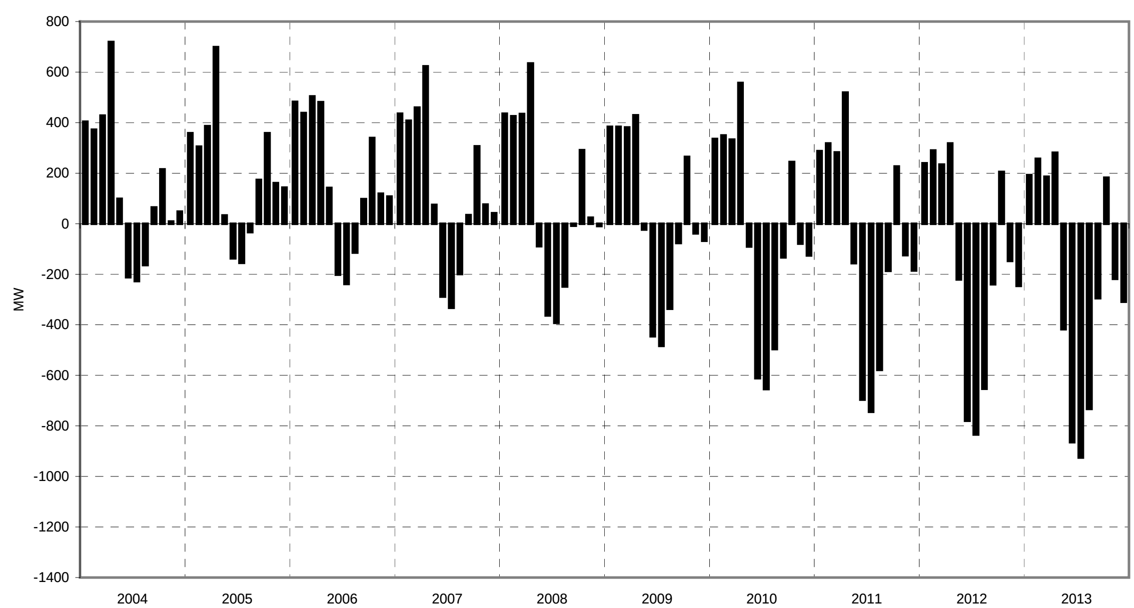


Figure 9 Monthly Peak-hour Surplus / Deficiency
Median Water, Median Load, Existing and Committed Resources



Transmission Adequacy

Prior to 2000, Integrated Resource Plans often emphasized acquisition of energy rather than construction of generating resources to satisfy load obligations. Transmission limitations were not a major impediment to Idaho Power's purchasing power to meet its service obligations. Idaho Power Company recognized that transmission constraints began to place limits on purchased power supply strategies starting with the 2000 Integrated Resource Plan. To better assess the adequacy of the power supply and the transmission system, Idaho Power Company analyzed transmission conditions for all hours of the ten-year planning period as part of the 2004 Integrated Resource Plan.

The transmission adequacy analysis reflects Idaho Power Company's contractual transmission obligations to provide wheeling service to the BPA loads in Southern Idaho. The BPA loads are typically served with a combination of energy and capacity from the Pacific Northwest and several United States Bureau of Reclamation projects located in Southern Idaho. The contractual transmission obligations are detailed in four Network Service Agreements under the Idaho Power Open Access Transmission Tariff.

Analyzing the transmission limitations during the peak hour of each month allows Idaho Power to assess the adequacy of the transmission system to serve Idaho Power and the BPA customers with energy from the Pacific Northwest. The BPA loads in July 2004 were forecast to be approximately 325 MW. The BPA loads were modeled as being served by a combination of approximately 55 MW of Southern Idaho USBR generation and approximately 270 MW of wheeled power from the Pacific Northwest.

The results of the transmission analyses indicate that the Northwest to Idaho path is most likely to face transmission constraints in low water years. The Brownlee-East path is most likely to face constraints during normal to high water years. The transmission analysis shows monthly peak-hour transmission deficiencies when the Idaho Power resource deficiencies are met by energy purchases from the Pacific Northwest at the same time the transmission system is delivering energy to the BPA customers in Southern Idaho.

Figure 10 represents the monthly peak-hour transmission deficiencies for a median water and median load condition. Assuming that Bennett Mountain is available in June 2005, the first peak-hour transmission deficiency from the Pacific Northwest occurs in July of 2007 and has a magnitude of approximately 80 MW. July peak transmission deficiencies for subsequent years typically increase by approximately 90 MW per year.

Figure 11 represents the monthly peak-hour transmission deficiencies for a 70th percentile water and 70th percentile load condition. The magnitude of the transmission deficiency is 75 MW in July 2007. Transmission deficiencies for subsequent July peaks typically increase by approximately 80 MW per year. By 2013, transmission deficiencies begin to appear in May.

Figure 12 represents the monthly peak-hour transmission deficiencies for a 90th percentile water and 70th percentile load condition – the conditions used in transmission planning. The 90th percentile water and 70th percentile load conditions presented in Figure 12 are used to establish the timing and magnitude of future peaking resources. The magnitude of the transmission deficiencies is 54 MW in July 2004. Assuming that the Bennett Mountain

Plant is available in June 2005, the July peak-hour deficiency is reduced to 3 MW. Transmission deficiencies for subsequent July peak conditions increase by approximately 90 MW per year. By 2013 transmission deficiencies occur from May through September and reach nearly 800 MW.

Figure 10 Monthly Peak-hour NW Transmission Deficit
Median Water / Median Load

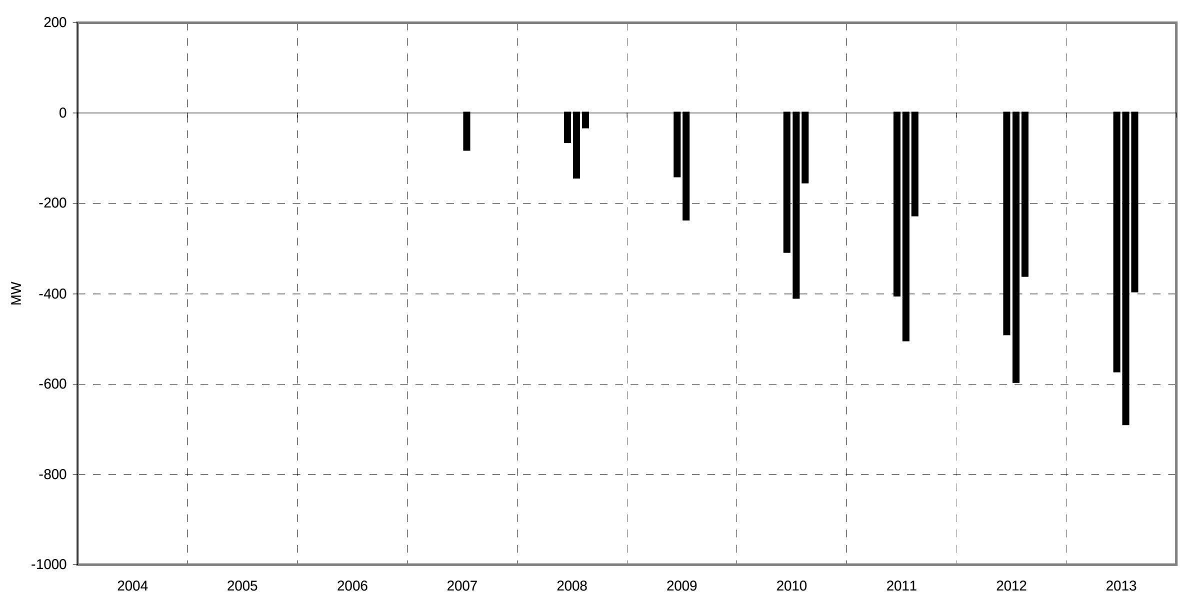
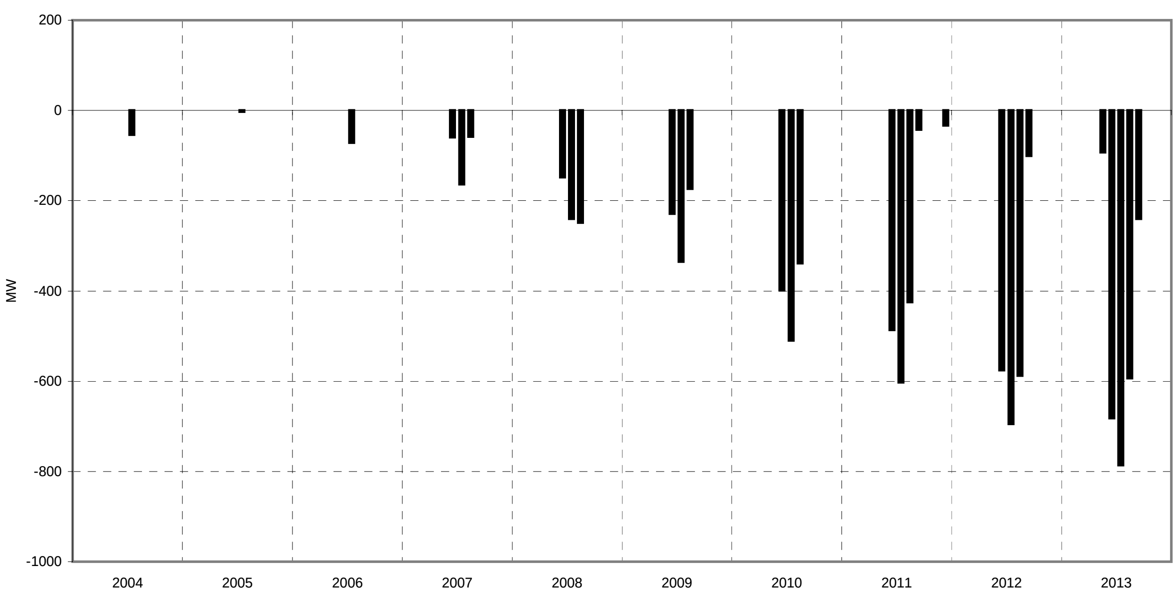


Figure 11 Monthly Peak-hour NW Transmission Deficit
70th Percentile Water, 70th Percentile Load, Existing and Committed Resources

Figure 12 Monthly Peak-hour NW Transmission Deficit
90th Percentile Water, 70th Percentile Load, Existing and Committed Resources



5. Potential Resource Portfolios

Resource Cost Analysis

The individual costs of a variety of potential supply-side and demand-side resources were analyzed to develop potential resource portfolios. The results of the resource cost analysis were used to analyze different resource combinations that could satisfy Idaho Power's energy needs. The results of the resource cost analysis are shown in Figure 13 and 14. The levelized costs shown for each resource represent the estimated annual revenue requirement the utility would require to construct and operate an energy resource over a period of 30 years. Resource costs are presented as:

- Levelized fixed cost per kilowatt per month of installed capacity, and
- Overall levelized cost per megawatt hour of expected plant or program output, given assumed capacity factors.

The general economic parameters used in the resource cost analysis are

1. An O&M escalation rate of 2.52 percent, based on an annual trend of consumer price inflation.
2. A discount rate of 7.20 percent based on Idaho Power's weighted average cost of capital at the end of 2003 and rate of return on common equity requested by the company in the 2003 general rate case filing with the Idaho Public Utility Commission.
3. An assumed 30-year book life for all supply-side resources, and a 30-year program life for each demand-side resource.

Since completing the portfolio financial analysis, Idaho Power has received Order 29505 from the Idaho Public Utilities Commission. Order 29505 calls for an allowed return on common equity (ROE) of 10.25 percent, down from 11.2 percent the company proposed in the filing within the Commission. The resulting after-tax discount rate is 6.7 percent using the 10.25 percent return on common equity. Idaho Power Company analyzed the lower discount rate and recognized that the lower rate will have an equal effect on all the resource portfolios and the lower discount rate will not affect the portfolio ranking.

Figure 13 Supply-Side Resources and Demand-Side Programs
30-Year Nominal Levelized Fixed Costs

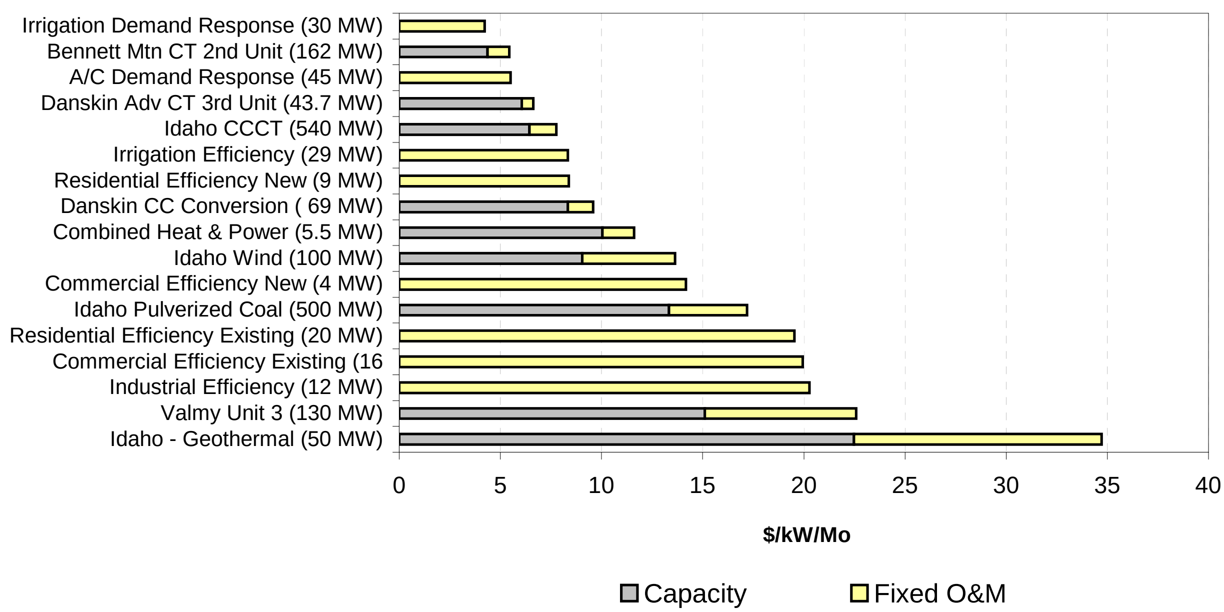
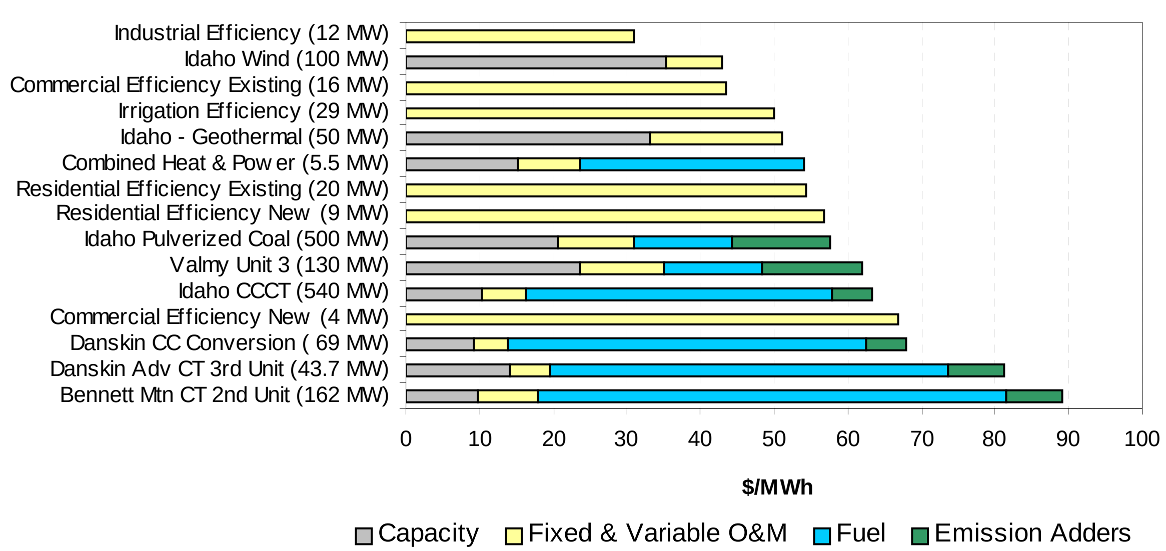


Figure 14 Supply-Side Resources 30-Year Nominal Levelized Cost of Production



Idaho Power's resource needs change throughout the planning period. Peaking resources are needed early in the planning period to serve summertime peak loads. As the customer load continues to grow, and resources to supply that load growth are needed for more and more hours of the year, it becomes more cost effective for Idaho Power Company to add baseload resources.

Resource cost inputs, gas and coal forecasts, and other significant financing and operating assumptions are shown in the *Technical Appendix*.

30-Year Levelized Fixed Cost per Kilowatt per Month

The capacity cost portion of a supply-side resource levelized fixed cost includes the components of cost of capital, depreciation, and state and federal income taxes. The construction cost figures used to calculate annual resource capacity charges include estimated transmission infrastructure and upgrade costs based on the sites Idaho Power considered to be likely locations for each resource. Supply-side resource construction costs also include Allowance for Funds used During Construction (AFUDC – capitalized interest). The non-fuel operation and maintenance (O&M) portion of each supply-side resource's levelized fixed cost includes estimates for property taxes and property insurance premiums.

The levelized cost for each of the demand-side resource options includes annual administrative and marketing costs of the program, annual incentive or rebate payments (for the demand-response programs), and annual participant costs (for the energy-efficiency programs). The annual fixed cost streams for each supply-side and demand-side resource are summed and levelized over an assumed 30-year life. The levelized costs are presented as dollars per kilowatt of plant capacity per month. Figure 13 provides a combined ranking of all of the supply-side and demand side resource options, in order of lowest levelized fixed cost per kilowatt per month.

30-Year Levelized Cost of Production

The levelized cost of production figures presented for the supply-side resources contain the same carrying cost, and non-fuel O&M components listed in the nominally levelized fixed cost of operation analysis detailed previously. In addition, the levelized variable cost components including fuel and variable O&M expenses for each supply-side resource are included in the estimates. Estimated capacity factors, based on generation technology and other known engineering factors, are applied to the estimated generation output of each supply-side resource to determine the annual overall MWh output.

The annual MWh output (energy savings) for each of the demand-side resource options is determined by multiplying its annual peak MW capacity by the total number of hours in the year the resource is expected to provide the energy savings. The program costs are presented as levelized on an annual basis for the sake of comparison. Both fixed and variable annual cost streams for each supply-side and demand-side resource are summed and levelized over an assumed 30-year life. The levelized costs are presented as dollars per annual megawatt hour of resource output for supply side resources, or program savings for demand-side resources. Figure 14 shows the combined ranking of all of the supply-side and demand-side resource options ranked by the levelized cost of production.

Supply-Side Resource Costs

The fixed-costs of production are shown in Figure 13. Figure 14 shows the 30-year supply-side nominally levelized costs for the same resources. Based on the 30-year costs of production, Idaho wind is the leading baseload supply-side resource. For an energy resource, Idaho wind also appears quite favorable when the fixed costs are considered as shown in Figure 13. Coal-fired generation falls in the middle of the list when considering either fixed-cost or operating costs.

Simple-cycle combustion turbines similar to Idaho Power Company's Danskin and Bennett Mountain plants are the lowest cost peaking resource based upon low fixed costs. The simple-cycle combustion turbines do have high operating costs, but the operating costs are not as important when the resource is only used a few hours per year to meet peak demand.

Supply-Side Resource Options

Included below are brief descriptions of the supply-side resources considered in the 2004 Integrated Resource Plan. The estimated power supply costs for each resource listed below were analyzed and tested using the Aurora Electric Market model. In addition, the demand-side resource options described later in this chapter were also considered in the power supply costs analysis.

Bennett Mountain CT 2nd Unit

The costs for the second Bennett Mountain unit are based on a 162 MW, simple cycle combustion turbine generator identical to Bennett Mountain Unit 1. The gas delivery infrastructure planned for Bennett Mountain Unit 1 can be expanded for one additional unit of similar size. Transmission modifications and the fuel expansion would be required and are included in the cost estimates.

Danskin CT Advanced CT Additional Units

The costs for additional units at the Danskin Plant are based on 43.7 MW, aero-derivative combustion turbines operating in simple cycle mode. The existing natural gas delivery infrastructure at Danskin is adequate for two additional units. Transmission modifications and expansion would be required and are included in the cost estimates.

Danskin CC Expansion – Incremental

Expanding the Danskin generating facility to include a heat recovery steam generator (HRSG) connected to the steam turbine-generator to take advantage of the exhaust heat from the two existing Danskin combustion turbines. The expansion would increase the Danskin facility capacity by 69 MW and would permit the facility to operate as a baseload plant. The existing natural gas delivery infrastructure at Danskin is adequate for the addition. Transmission modifications and expansion would be required and are included in the costs.

Combustion Turbine Advantages and Disadvantages

Combustion Turbine Advantages

- Low capital cost
- Proven technology
- Short construction period
- Modular, can be built in incremental units
- Relatively low CO_2 emissions for a thermal resource
- Well-suited to peaking operations

Combustion Turbine Disadvantages

- Expensive to operate
- High fuel price volatility
- Poorly suited to baseload operation

Combined Heat & Power

Idaho Power Company can form a partnership with some industrial customers by installing Combined Heat & Power (CHP) generating units at industrial facilities that have existing steam requirements. A common type of CHP system uses a combustion turbine generator to produce electrical power and also produces steam by installing a heat recovery steam generator in the exhaust path of the combustion turbine. The electrical power would be delivered through the Idaho Power distribution and transmission system and the steam would be used to meet the industrial facility requirements. The cost for combined heat and power units are based only on the electrical generating portion of the facility. It is undetermined whether the steam would be sold to the industrial facility or if the industrial facility would own the steam-generating portion. The cost estimates for combined heat and power reflect a typical project. Actual costs are highly dependent on the actual plant configuration as well as the contract and ownership agreements.

Combined Heat and Power Advantages

- Increases overall efficiency of generation system
- Fuel is already used by the industrial processes
- Typically close to load centers requiring fewer transmission upgrades
- Shared operation with customers

Combined Heat and Power Disadvantages

- Subject to natural gas price volatility
- Shared operation with customers
- Actual costs and ownership arrangements are unknown

Geothermal

Idaho Power Company has received inquiries to construct geothermal generating plants located within, or near to, the Idaho Power service territory. The costs are based on figures provided as estimates from two Idaho-based geothermal development companies. The costs include electrical transmission necessary to interconnect the facility to the Idaho Power transmission system. The most promising geothermal resources are located in Eastern Idaho and it is assumed a geothermal generating plant would be located in Eastern Idaho. Delivering the energy to the Idaho Power Company load center in the Treasure Valley will require significant upgrades to the Borah-West and Midpoint-West transmission paths.

Geothermal Advantages

- Renewable resource
- No CO_2 emissions
- Possible production tax credits

Geothermal Disadvantages

- Unproven resource in Idaho
- Unknown operating cost
- Toxic compounds dissolved in water may require disposal

Valmy Unit 3

Idaho Power Company can expand the generation capacity at the Valmy plant in Northern Nevada by installing a third generating unit. The costs for an additional coal-fired generating unit at Valmy are based on Idaho Power Company 50 percent ownership of a 260 MW generator. It is assumed the other half of the unit ownership would be assigned to Sierra Pacific Power Company – the operator of the Valmy project. The costs include the substantial electrical transmission expansion required to deliver 130 MW to the Idaho Power system. The Valmy plant infrastructure was designed for potential expansion.

Pulverized Coal

Idaho Power could construct a new 500 MW pulverized-coal fired generating facility somewhere within the Idaho Power Company service territory. Costs for the coal-fired generating unit are based on internally generated cost estimates based on industry quotes and the US Department of Energy Annual Energy Outlook. The costs include a substantial electrical transmission expansion. It is assumed that the coal will be delivered to the plant by rail.

Coal Advantages and Disadvantages

Coal Advantages

- Low fuel cost
- Low fuel price volatility when compared to natural gas
- Low operating cost
- Proven technology
- Well-suited to baseload operations

Coal Disadvantages

- High CO_2 emissions
- High capital cost
- Community acceptance can be an issue
- Poorly-suited to peaking operations

Wind

Idaho Power Company could construct a wind based generating plant located near the Idaho Power service territory. Wind cost estimates are based on data provided in the DOE Annual Energy Outlook, data from the Northwest Power and Conservation Council, data provided by wind developers, as well as internal Idaho Power estimates. The costs include electrical transmission necessary to connect the facility to the Idaho Power transmission system. The most promising wind resources are located in Eastern Idaho and it is assumed the wind turbines would be located in Eastern Idaho. Delivering the energy to the Idaho Power Company load center in the Treasure Valley will require significant upgrades to the Borah-West and Midpoint-West transmission paths.

Wind is an intermittent seasonal resource in many areas including the prospects in Eastern Idaho. To estimate wind resource output, Idaho Power used a combination of data from wind developers and the Northwest Power and Conservation Council. Wind output was estimated for three time periods; annual, monthly, and hourly during peak hours in July. The estimate used for annual energy output is a 35 percent capacity factor. The 35 percent capacity factor means that a wind project with a nameplate capacity of 100 MW will produce an average of 35 MW over the course of a year. Monthly energy output was derived from the normalized monthly wind energy distribution for areas characterized as Basin and Range (which includes southern Idaho) in the Northwest Power and Conservation Council's wind resource characterization paper. The NWPC distribution is included as part of the *Technical Appendix*.

Wind output during peak hours in July was based on actual data provided by a wind developer for a specific project. The data indicate that, during July between the hours of 4:00 PM and 8:00 PM, a 100 MW wind project will produce 5 MW or more 70 percent of the time.

However, the wind data also indicate that the project will produce 5 MW or less 30 percent of the time. Based on the wind data, Idaho Power assumes that a 100 MW wind project would provide 5 MW of capacity during summer peak hours.

If a number of wind projects are developed with sufficient geographic dispersion, then it is possible that the amount of peak-hour summertime capacity provided by projects may increase due to the geographic dispersion. Wind capacity values will be revisited when actual wind project data become available.

Wind Advantages

- Renewable resource
- No fuel cost
- No CO_2 emissions
- Moderate capital cost
- Low operating cost

Wind Disadvantages

- Unproven resource in Idaho
- Uncertain availability
- May require additional capital expense for backup generation
- Costs may be distorted with Production Tax Credits
- Future of Production Tax Credits is unknown

Demand-Side Management and Pricing Options

Idaho Power Company has worked with the Energy Efficiency Advisory Committee and outside consultants to identify potential demand-side programs that may be cost-effective. Potential programs were identified in all four major customer classes – residential, commercial, irrigation, and industrial. Potential DSM programs and the program size in MW are identified in Table 10.

Idaho Power analyzed a number of DSM options through a pre-screening analysis and then used the Aurora Electric Market Model to determine how each option impacts the Idaho Power Company power supply costs. The pre-screening analysis compared estimated program costs and hourly impacts to a set of alternative hourly costs. The alternative hourly costs represented both heavy and light load market purchase estimates as well as gas-fired peaking generation costs. The set of alternative hourly costs was used as a pre-screen in order to represent the value of summer peaking resources when designing potential DSM resource options. The pre-screening analysis resulted in eight DSM options – six energy efficiency options and two demand response – that had benefit to cost ratios greater than 1.0 (static analysis).

Table 10 Idaho Power Company Potential Demand-Side Programs

Demand Response Programs:

- Irrigation Demand Response (30 MW on peak)
- Air Conditioning Demand Response (45 on peak MW)

Energy Efficiency Programs:

- Commercial Efficiency, Existing Construction (16 MW on peak, 10 aMW energy)
- Commercial Efficiency, New Construction (4 MW on peak, 1 aMW energy)
- Industrial Efficiency (12 MW on peak, 11 aMW energy)
- Residential Efficiency, Existing Construction (20 MW on peak, 10 aMW energy)
- Residential Efficiency, New Construction (9 MW on peak, 2 aMW energy)
- Irrigation Efficiency (29 MW on peak, 7 aMW energy)

The energy and capacity estimates for the demand response programs and energy efficiency programs outlined in Table 10 identify the expected returns of the fully installed 10-year programs. Since implementation is not planned to start until 2005, there will only be nine years of program performance included during the 2004-2013 planning period of the 2004 Integrated Resource Plan. The nine-year performance period produces a small difference between the results expected at the end of the planning period in 2013 and the results expected after a full 10 years of program operation. The top four energy programs are expected to provide 48 MW of peak reduction by 2013. The same four programs are expected to provide an additional 6 MW of peak reduction in 2014, bringing the total peak reduction to 54 MW after ten years of program performance in 2014. Because the 2004 IRP only addresses the 2004-2013 planning period, the 48 MW of peak reduction achieved by 2013 is referred to throughout the remainder of the 2004 Integrated Resource Plan.

Idaho Power then constructed a number of resource portfolios containing a combination of supply and demand side resources that were analyzed with the Aurora model (dynamic analysis). The purpose of the Aurora analysis was to identify the hourly impacts of the DSM options on Idaho Power's simulated power supply costs. Because of the difficulty of modeling the two demand response options in Aurora, Idaho Power evaluated the impacts of the two demand response programs outside of the Aurora model – comparing the program's capacity costs to those of supply-side peaking resources (Figure 13). Both demand response options were determined to be cost effective based on their dispatchability and peak benefits. Each of the six energy efficiency options was analyzed individually to determine the impact on the present value of power supply costs for a given portfolio. In the analysis, all six energy efficiency options showed that power supply costs were reduced when each DSM option was added to the portfolio.

In order to determine which of the six energy efficiency options should be included in the finalist portfolios, Idaho Power looked at the 30-year present value of the reduction in power supply costs (benefit), and the present value of the DSM option's Total Resource Cost (cost), and developed benefit to cost ratios derived from the Aurora analysis. The resulting ranking of the six energy efficiency options based on the 30-year benefit to cost ratios is:

1. Commercial New Construction
2. Irrigation Efficiency
3. Industrial Efficiency
4. Residential New Construction Efficiency
5. Commercial Existing Construction Efficiency and
6. Residential Existing Construction Efficiency.

In addition to the two demand response options, Idaho Power Company chose to include the four highest-ranking energy efficiency options. The top four were selected for two reasons. First, it was felt that although the two lowest ranking options did have a benefit to cost ratio over one, that better options may be identified through the ongoing energy efficiency assessment analysis. The second reason for implementing the top four energy efficiency programs is that it will be an operational challenge to implement six large programs in the same year as indicated by the Action Plan. Idaho Power Company believes it would be prudent to concentrate its efforts on the four top programs. The energy efficiency assessment analysis, by Quantum Consulting, will be finished this fall and will provide more information to evaluate the energy efficiency programs. Additional details on the analysis are included in the *Technical Appendix*.

The demand-side programs and supply side resources are compared in a combined resource stack as shown in Figure 13 and Figure 14. Figure 13 and Figure 14 show that several demand-side programs compare favorably with traditional thermal generation. The attributes of the programs and resources and their contribution to the resource portfolio are fully discussed in Chapter 6 as well as the *Technical Appendix*.

Demand-Side programs reduce demand and energy at the point of consumption. Transmission and distribution losses are not a factor in DSM programs. In order to accurately compare DSM programs with supply-side resources, the energy and capacity estimates from the demand-side programs were increased by 10 percent to account for the losses that would occur if the energy and capacity were remotely generated by supply-side resources.

Idaho Power Company proposed seasonal rates as part of the 2003 General Rate Case filed with the Idaho Public Utilities Commission (IPC-E-03-13) because the cost to serve customers during the summer months is greater than during the remainder of the year and Idaho Power Company believes that electric rates should reflect the actual cost of service. Idaho Power Company proposed that the energy rate for residential customers should be 25 percent greater during the summer months than non-summer months. The Idaho PUC ultimately approved a summer rate 12.6 percent greater than the base rate for all energy greater than 300 kWh per month (Idaho PUC Order 29505). Seasonal rates are a new pricing system for Idaho Power customers and the impacts of the seasonal rates have not been included in the 2004 Integrated Resource Plan. Customer billing data gathered during the summers of 2004 and 2005 will be used to assess the impact of seasonal rates on consumption.

Demand-side measures and energy conservation measures are often seen as synonymous. Unfortunately, generic energy conservation programs are unlikely to be sufficient to meet the peak deficiencies facing Idaho Power during the near term of this resource plan. Specific demand-side measures and pricing options that target peak-hour demand reduction are more likely to address the peak deficiencies facing Idaho Power Company. Idaho Power Company has analyzed both energy efficiency and peak-reduction demand-side measures in the 2004 Integrated Resource Plan.

Presently, Idaho Power Company has a pilot residential air conditioning program and nearly 200 residential customers have voluntarily enrolled in the program. The program will be expanded to another 300 residential customers this summer. During times of extreme need, such as during the summer peak, Idaho Power briefly interrupts program participant's air conditioners. Interruption periods are commonly 15 minutes or less. Idaho Power Company has divided the program participants into two groups, and by alternately interrupting each group, the group air conditioning demand can be reduced by half.

It is interesting to note that Idaho Power Company adds almost 10,000 residential customers each year and most of these new customers have air conditioning. A simple analysis suggests that Idaho Power Company would have to enroll 20,000 customers in the air conditioning cycling program each year to maintain residential air condition demand at the current level.

Several programs identified by the EEAG appear to have promise. Due to the nature and timing of the projected peak deficits and transmission overloads, conservation, demand-side measures, and pricing options must be carefully designed and targeted to cost-effectively address the projected deficits.

Idaho Power anticipates that some of the energy efficiency and demand-response programs will be conducted through a competitive process using requests for proposals. Additionally, Idaho Power intends to have the effectiveness of the programs assessed using an independent evaluation process, again likely conducted using requests for proposals.

Social Costs

All electric power resources have costs, benefits, and impacts beyond the construction and operating costs that are included in the price of electricity. The non-internalized costs include the air pollution and natural resource depletion associated with thermal generation, the effects on aquatic life and recreation associated with hydroelectric dams, and the aesthetic and bird mortality issues associated with renewable wind power.

Order 93-695 from the Oregon Public Utility Commission specified costs associated with the level of carbon dioxide (CO_2), nitrogen oxides (NO_x), and total suspended particulate (TSP) emissions from new thermal generating plants. SO_2 emission costs are included in the calculation of direct utility costs through modeling of the emission allowance system established by the Clean Air Act. The sensitivity of the resource portfolio to the externality costs specified by the OPUC in Order 93-695 has been investigated as part of the portfolio analysis (NO_x, TSP, and CO_2,). The OPUC order specified costs in 1990 dollars and the costs have been escalated to 2004 dollars for the Integrated Resource Plan.

Table 11 Idaho Power Company

Externality Cost Ranges for Thermal Plant Emissions

Combinations of NO_x, TSP, and CO_2 Cost Levels in Dollars per Ton						
Emission	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6
NO_x	$2,460	$2,460	$2,460	$6,151	$6,151	$6,151
TSP	$2,460	$2,460	$2,460	$4,921	$4,921	$4,921
CO_2	$12.30	$30.76	$49.21	$12.30	$31.76	$49.21

Table 11 shows the six sets of social cost additions identified in the OPUC order. The order states that each utility should conduct its sensitivity studies with at least one of these six combinations of social costs. Idaho Power's preliminary analysis indicated that the CO_2 cost was the most significant of the three (NO_x, TSP, and CO_2). Idaho Power conducted sensitivity studies at three different CO_2 cost levels – $0 per ton, $12.30 per ton, and $49.21 per ton, escalating at 2.5 percent per year. TSP and NOx costs were held constant in all three studies at $2460 per ton and $3000 per ton respectively.

The social costs shown in Table 11 do affect the resource and program choices. Coal-fired generation is particularly sensitive to externality costs. The CO_2 costs in dollars per ton can be roughly translated into equivalent dollars per MWh. For example, a CO_2 cost of $12 per ton would roughly translate into $12 per MWh for a coal-fired plant, $5 per MWh for a combined cycle plant, and $7 per MWh for a combustion turbine. The values shown in Figure 13 and Figure 14 indicate that an externality costs have the potential to affect the relative position of coal-fired generation in the resource portfolio. Coal-fired generation resources are long-lived assets and Idaho Power and its customers face significant long-term price uncertainty with respect to social costs. Portfolio risk is presented in Chapter 6. Additional details on the ranking of the portfolios under the three different CO_2 cost scenarios are presented in the *Technical Appendix*.

Resource Portfolios

Twelve different portfolios were analyzed as part of the 2004 Integrated Resource Plan. Each portfolio will fully meet the Idaho Power Company projected monthly energy needs under the 70^{th} percentile water and 70^{th} percentile load planning criteria. Each portfolio will eliminate the projected peak-hour transmission overloads from the Pacific Northwest under the 90^{th} percentile water and 70^{th} percentile load conditions. The resource portfolios were developed to explore a variety of different resource alternatives and to analyze the costs and benefits associated with each resource strategy.

The resource portfolios varied from a portfolio consisting entirely of combustion turbines to a portfolio containing 1,000 MW of wind generation with over 800 MW of combustion turbines for backup capacity. Other portfolios included a predominately coal-fired portfolio which included almost no natural gas fired generation, and a number of diversified portfolios that include varying amounts of wind, geothermal, coal, simple and combined-cycle combustion turbines, and demand-side resources.

The 30-year portfolio power supply costs include both the carrying and operating costs of the various additional supply-side and demand-side resources proposed within each portfolio, as well as the carrying and operating costs of Idaho Power's existing and committed resources. Unless otherwise noted, portfolio power supply costs are based on 70th percentile water condition, 70th percentile load conditions, expected fuel price forecasts, and a CO_2 emission cost of $12.30 per ton. All of these costs are stated as a 30-year present value, using the same financing assumptions as outlined previously in the discussion of the resource cost analysis.

The capital costs listed for each portfolio have been escalated based on the construction timing and lead times of the various resources within each portfolio and do not include any estimates of Allowance for Funds Used During Construction (AFUDC, capitalized interest). AFUDC was considered in the determination of each portfolio's carrying cost.

All the portfolios assume that Idaho Power Company will own and operate the resources. If the energy and capacity were obtained through Power Purchase Agreements or other arrangements, the capital costs would be lower and the power supply costs would be higher. A full listing of the portfolios with additional detail regarding the portfolio costs, capacity, and resource timing is included in the *Technical Appendix*.

Portfolio Selection

The twelve original portfolios were analyzed and ranked under four different scenarios:

1. No CO_2 tax, expected gas prices, production tax credit (PTC) continues to be renewed
2. CO_2 tax at $12.30 per ton beginning in 2008, expected gas prices, PTC continues to be renewed
3. CO_2 tax at $49.21 per ton beginning in 2008, expected gas prices, PTC continues to be renewed
4. CO_2 tax at $12.30 per ton beginning in 2008, expected gas prices, no PTC

The portfolio ranking is reported in Table 12. The Aurora Electric Market Model was used to calculate the 10-, 20-, and 30-year present value of the portfolio power supply costs for each of the twelve portfolios, under each of the above four scenarios. Rankings were assigned to each portfolio based on the present value of its portfolio power supply cost – the lowest cost portfolio was ranked 1 and the highest cost portfolio was ranked 12. The portfolio rankings were summed and considered in two separate cases:

a. Sum of rankings – all scenarios, all years
b. Sum of rankings – all scenarios 30 year only

Table 12 Portfolio Comparison

Portfolio	Additional Capacity	Power Supply Costs	Capital Costs	CO_2 Ranking**
Portfolio 0	734 MW	$7,870 M	$1,211 M	6
Portfolio 1	810 MM	$8,513 M	$421 M	2
Portfolio 2	750 MW	$8,302 M	$857 M	7
Portfolio 3*	**784 MW**	**$7,982 M**	**$1,690 M**	**1**
Portfolio 4	722 MW	$8,187 M	$810 M	4
Portfolio 5	794 MW	$8,157 M	$904 M	11
Portfolio 6*	**784 MW**	**$8,031 M**	**$805 M**	**8**
Portfolio 7*	**1,084 MW**	**$7,555 M**	**$1,352 M**	**10**
Portfolio 8*	**935 MW**	**$7,748 M**	**$912 M**	**12**
Portfolio 9	853 MW	$7,961 M	$1,143 M	9
Portfolio 10	893 MW	$7,971 M	$904 M	3
Portfolio 11*	**939 MW**	**$7,385 M**	**$1,238 M**	**5**

* *Portfolios selected for additional analysis*
** *CO_2 ranking based on PV of carbon costs at $12.31 per ton, 1 = lowest*

Case a. and Case b. were analyzed separately. Each of the 12 portfolios received equal weighting in either case. The results were nearly identical for Case a. and Case b., with Portfolio 11 receiving the top ranking in either case. Since the resources being considered in this plan are long-lived assets, Idaho Power decided that Case b., considering only the 30 year present value of portfolio power supply costs, was the appropriate way to rank the portfolios. More detail summarizing the portfolio ranking analysis is included in the *Technical Appendix*.

6. Risk Analysis

Idaho Power Company has identified five of the twelve portfolios for risk analysis. That does not mean that the other seven portfolios are unacceptable, but the five portfolios selected for risk analysis dominate the other seven portfolios in the cost analysis. Estimated transmission costs for the five selected portfolios were refined to reflect acquisition and integration of the entire resource portfolio. The five selected portfolios are:

Portfolio 3 – Wind + Natural Gas Backup Generation

Acquisition Schedule	Description (total MW)	Resource Type
2006, 2007, 2008, 2009, 2010	1000 MW Wind *(50 MW Capacity)*	Renewable
2009	50 MW Geothermal	Renewable
2007, 2008, 2011, 2012	648 MW Combustion Turbines	Thermal
Additional Capacity (2013)	*784 MW*	
PV Portfolio Power Supply Costs	*$7,712 M*	
Construction Cost	*$1,690 M*	
Carbon Tax (CO_2) Ranking	*1 – lowest PV of CO_2 emission adders*	

Portfolio 6 – Balanced Resources

Acquisition Schedule	Description (total MW)	Resource Type
All years	48 MW DSM	Demand-Side
All years	76 MW Demand Response	Demand-Side
2006, 2007	200 MW Wind *(10 MW Capacity)*	Renewable
2007	12 MW Combined Heat & Power	Thermal
2007	88 MW Combustion Turbines	Thermal
2008	50 MW Geothermal	Renewable
2010	500 MW Coal (seasonal)	Thermal
Additional Capacity (2013)	*784 MW*	
PV Portfolio Power Supply Costs	*$7,935 M*	
Construction Cost	*$805 M*	
Carbon Tax (CO_2) Ranking	*8*	

Portfolio 7 – Balanced Resources

Acquisition Schedule	Description (total MW)	Resource Type
All years	48 MW DSM	Demand-Side
All years	76 MW Demand Response	Demand-Side
2006, 2007	200 MW Wind *(10 MW Capacity)*	Renewable
2007	12 MW Combined Heat & Power	Thermal
2007	88 MW Combustion Turbines	Thermal
2008	100 MW Geothermal	Renewable
2010	250 MW Coal	Thermal
2013	500 MW Coal (seasonal)	Thermal
Additional Capacity (2013)	*1084 MW*	
PV Portfolio Power Supply Costs	*$7,699 M*	
Construction Cost	*$1,352 M*	
Carbon Tax (CO_2) Ranking	*10*	

Portfolio 8 – Balanced Resources with Coal Emphasis

Acquisition Schedule	Description (total MW)	Resource Type
All years	48 MW DSM	Demand-Side
All years	76 MW Demand Response	Demand-Side
2006	100 MW Wind *(5 MW Capacity)*	Renewable
2006, 2007, 2008	36 MW Combined Heat & Power	Thermal
2007	20 MW Geothermal	Renewable
2007	250 MW Coal	Thermal
2009	500 MW Coal (seasonal)	Thermal
Additional Capacity (2013)	*935 MW*	
PV Portfolio Power Supply Costs	*$7,920 M*	
Construction Cost	*$912 M*	
Carbon Tax (CO_2) Ranking	*12*	

Portfolio 11– Balanced Resources

Acquisition Schedule	Description (total MW)	Resource Type
All years	48 MW DSM	Demand-Side
All years	76 MW Demand Response	Demand-Side
2006, 2007, 2010	350 MW Wind *(18 MW Capacity)*	Renewable
2007, 2010	48 MW Combined Heat & Power	Thermal
2007	88 MW Combustion Turbines	Thermal
2008	100 MW Geothermal	Renewable
2010	62 MW CT / Distributed Gen	Thermal
2011	500 MW Coal (seasonal)	Thermal
Additional Capacity (2013)	*939 MW*	
PV Portfolio Power Supply Costs	*$7,547 M*	
Construction Cost	*$1,238 M*	
Carbon Tax (CO_2) Ranking	*5*	

Table 13 Risk Categories

Category	Risk Type
Quantitative Risk	1. Capital Risk 2. Production Tax Credits (wind) 3. Capacity Risk (wind) 4. Fuel Prices 5. CO_2 Taxes
Qualitative Risk	1. Public Policy changes 2. Resource commitment 3. Resource timing 4. Resource siting 5. Public acceptance 6. DSM Implementation Risk

The objective of the risk analysis was to identify a portfolio that performs well in a variety of possible scenarios. Besides the quantitative risk of price fluctuations, Idaho Power is also interested in the qualitative risks associated with events like policy changes, resource commitment risk, and environmental risk. The risk categories are presented in Table 13.

Quantitative Risk

Idaho Power has conducted a boundary analysis to assess the quantitative risks. For example, Idaho Power has analyzed the impacts on the resource portfolios under three CO_2 emission tax scenarios – no CO_2 tax, a \$12.30 per ton tax, and a \$49.21 per ton tax. Likewise, Idaho Power has analyzed each portfolio's performance if natural gas prices turn out to follow the low price scenario or the high price scenario. Production Tax Credits have been handled in a similar fashion. Idaho Power assessed portfolio performance if production tax credits for wind are allowed to expire, and also if the production tax credits are renewed.

The capacity risk identified for wind is the risk that the resource will not deliver the contract energy due to resource and technology constraints. The capacity risk for wind generation was quantified based on weather data collected at potential generation sites and the wind capacity risk was included in the portfolio analysis. For example, the capacity estimate for a 100 MW wind generator at the 70^{th} percentile is 5 MW during the summer peak hours. Wind capacity estimates are discussed in more detail in Chapter 5.

Qualitative Risk

The qualitative risks are more difficult to analyze. The objective is to select a portfolio that is likely to withstand unforeseen events associated with the qualitative risk.

The DSM implementation risk is the risk that the actual energy savings and peak reductions from the projected DSM programs will be different than the projected energy savings and peak reduction targets. Should the actual energy savings and peak reductions be less than the estimated values, Idaho Power Company will be required to acquire additional supply-side resources to meet the customer load. If the DSM programs exceed the estimated savings, future supply-side resources may be delayed.

Idaho Power is a regulated utility with an obligation to serve and Idaho Power Company faces regulatory risk. Idaho Power expects that future resource additions will be approved for inclusion in rate base and that Idaho Power Company will be allowed to earn a fair rate of return on its investment. Idaho Power believes that by expanding public involvement in the IRP process (working with the IRP Advisory Council), and by addressing several of the Idaho PUC concerns identified in the order acknowledging the 2002 IRP, that Idaho Power has at least partially addressed the regulatory risk associated this plan.

Significant changes in public policy represent risks that must be considered in a resource plan involving long-lived assets. In addition to the CO_2 emissions tax, another possible change in public policy that could impact Idaho Power Company and other utilities is implementation of a renewable portfolio standard. The impacts associated with enactment of a renewable portfolio standard have been considered in this plan. Although the impacts are not presented in quantitative terms, the preferred portfolio does position Idaho Power Company to meet future renewable portfolio standards in the event such standards are enacted. Once the preferred portfolio in service, nearly ten percent of the Idaho Power Company generating resources will be non-hydro renewable resources.

Idaho Power Company faces risk in the resource timing and commitment. Idaho Power has attempted to identify the time periods in which new resources are needed. There are a number of factors that influence actual timing of resource need. Examples include economic growth in the service territory, electricity usage patterns, and performance of existing resources. At the Integrated Resource Plan Advisory Council meetings it was agreed that early commitment to a large resource might be inadvisable. The Council members thought that it would be more prudent to pursue a variety of resource types to spread the risk of policy, siting, and system integration issues. The preferred plan, and most of the finalist portfolios, addresses the uncertainty by adding resources in smaller increments. The smaller increments more closely match the projected need for additional capacity.

By utilizing a diverse mix of smaller, short lead-time resources, the preferred plan has the flexibility to adjust resource timing by either accelerating or deferring actual in-service dates to more closely match actual load growth. With the exception of the 500 MW coal-fired plant and the geothermal resources, most of the resources included in the preferred plan have a fairly short acquisition lead-time. The longer lead-time associated with constructing a coal-fired plant or a geothermal resource does present a commitment risk. Progress on the resource acquisition plan and the need to defer or accelerate a future resource will be addressed every two years in subsequent Integrated Resource Plans.

There are two other qualitative risks that are associated with having a generation system based on Snake River hydropower. Idaho Power Company has senior water rights on the Snake River and Idaho Power Company is very concerned about the declining base flows in the Snake River. The declining base flows have the potential to dramatically lower the energy output from the Snake River hydropower system. The 2004 Integrated Resource Plan is based on 70th percentile water conditions as determined by the historical record. If Snake River streamflows continue to decline, Idaho Power Company will require additional resources to meet the customer load. The declining Snake River flows has the interest of all parties including the State legislature, the State Department of Water Resources, the water users, the river naturalists, and Idaho Power Company.

Portfolio 11 proposes adding 350 MW of renewable wind-based generation. One reason that Idaho Power Company can economically add wind-based generation is that wind-based generation can be integrated into the hydropower system. Idaho Power Company intends to use the flexibility of the Snake River hydropower system, especially the operational flexibility of the Hells Canyon Project, to integrate the wind-based generation. Reductions in the streamflow flexibility of the Snake River hydropower system may negatively affect the ability of Idaho Power Company to economically integrate wind-based generation.

The risk analysis presented below combine quantitative risk with a subjective probability assessment of the boundary conditions. In all of the boundary condition cases, Idaho Power Company has assigned a probability estimate to the expected, high, and low, scenarios. The greatest likelihood is assigned to the expected case. For example, under the discount rate assessment of the capital risk, the expected case is assigned a probability of 80 percent, and the high and low cases are each assigned a probability of ten percent. The probability assignment may not be symmetric when assessing the other risk categories. The dollar impact under each scenario is then weighted by the assigned probability to arrive at an analytical probability assessment. The analytical probability assessments are then used to summarize the risks at the end of this chapter.

Capital Risk

Capital costs and construction cost of each portfolio represents the capital risk. The portfolios only consider mature technologies even though some of the resource types are unproven in Idaho (wind and geothermal). While capital construction costs are generally known for the various resources, there are always risks associated with any major construction project including the risk of cost overruns. The impacts associated with a 10 percent cost overrun are shown in the following table:

Construction Costs

Total Construction Costs *(No AFUDC)*

		P3	P6	P7	P8	P11
Portfolio Construction Cost		$1,690	$805	$1,352	$912	$1,238
Cost Increase Relative to Lowest Cost Portfolio		$884	$0	$547	$107	$433
Construction Risk Weight	10%					
Weighted Risk		$88	$0	$55	$11	$43

Dollars in Millions

Capital Costs

PV Power Supply Costs *(30 year, CO_2 at $12 per ton, includes wind PTC)*

		P3	P6	P7	P8	P11
Expected Rate (7.2%)		$7,982	$8,031	$7,555	$7,748	$7,385
High Rate (9.2%)		$6,257	$6,281	$5,989	$6,120	$5,854
Low Rate (5.2%)		$10,507	$10,604	$9,823	$10,116	$9,609
Expected relative to Expected		$0	$0	$0	$0	$0
Low relative to Expected		$2,525	$2,573	$2,268	$2,368	$2,224
High relative to Expected		-$1,725	-$1,750	-$1,566	-$1,628	-$1,531
Weights						
Expected	80%					
Low	10%					
High	10%					
Weighted Risk		$80	$82	$70	$74	$69

Dollars in Millions

Portfolio 6 has the lowest projected capital cost of the five portfolios and therefore also has the lowest construction cost risk.

Portfolio 11 is the least sensitive to discount rate changes. However, portfolios 7 and 8 face similar discount rate risks. Each of the other four portfolios is likely to face higher construction costs than Portfolio 11.

Production Tax Credit Risk

The Production Tax Credit for wind generation has expired. There are discussions in the US Congress of renewing the production tax credit for wind-powered generation. The 30-year power supply costs under the two production tax credit scenarios is presented below:

PV Power Supply Costs *(30 year, CO_2 at $12 per ton)*

		P3	P6	P7	P8	P11
Production Tax Credit		$7,712	$7,935	$7,699	$7,920	$7,547
No Production Tax Credit		$8,238	$8,059	$7,821	$7,970	$7,735
Expected relative to Expected		$0	$0	$0	$0	$0
No PTC relative to Expected		$526	$124	$122	$50	$188
Weights						
Expected	70%					
No PTC	30%					
Weighted Risk		$158	$37	$37	$15	$53

Dollars in Millions

As expected, the portfolios with the greatest quantities of wind-powered generation derive the greatest benefit from the production tax credit. Portfolios 3 and 11 have the largest quantity of wind-powered generation and face the greatest risk to changes in the US Tax Code with respect to wind-powered generation.

Natural Gas Price Risk

Idaho Power Company faces two types of natural gas price risk. Direct risk is the risk that Idaho Power faces to acquire natural gas to fuel its own resources. Indirect risk is the risk that Idaho Power Company faces when it acquires power from, or sells power in, the regional market where natural gas fired resources set power prices. The high prices during the summer of 2001 were partially the result of indirect risk. Portfolios that rely on market purchases will face a greater indirect natural gas price risk. The direct and indirect natural gas price risks are shown below:

Portfolio Fuel Cost Risk

PV Power Supply Costs *(30 year, CO_2 at $12 per ton, includes wind PTC)*

		P3	P6	P7	P8	P11
Expected Gas price		$7,712	$7,935	$7,699	$7,920	$7,547
Low Gas Price		$7,771	$8,026	$7,854	$8,095	$7,658
High Gas Price		$7,819	$8,048	$7,520	$7,755	$7,527
Expected relative to Expected		$0	$0	$0	$0	$0
Low relative to Expected		$59	$91	$155	$175	$111
High relative to Expected		$107	$113	-$179	-$165	-$20
Weights						
Expected	50%					
Low	20%					
High	30%					
Weighted Risk		$44	$52	-$23	-$15	$16

Dollars in Millions

The table shows the portfolio power supply costs under three different gas price scenarios. The portfolio power supply costs include both the expenses and revenues associated with all of the portfolio fuel supply costs, surplus sales, and costs associated with Idaho Power Company's existing resources. The coal-fired portfolios face price risk because the size of coal-fired generation necessitates some quantity of surplus sales until customer loads increase to match the resource size. For engineering design, financial, and construction reasons, coal-fired generation is generally added in large units with the idea that the excess generation will be sold at regional market prices for the few years that the Idaho Power system has surplus power. Like the renewable energy resources, portfolios that rely on coal face indirect natural gas price risk because the natural gas prices affect the prices at which the surplus power is sold in the regional market.

Carbon Tax Risk

It is likely that carbon dioxide emissions will be regulated within the thirty-year timeframe addressed in the 2004 IRP. Activity throughout the United States suggests that carbon dioxide emissions may be regulated in the relatively near future. The Climate Stewardship Act (S.139), introduced by Senators McCain and Lieberman, received 43 votes in the Senate in 2003. The bill is likely to be brought to a vote again this year, and a companion bill has already been introduced in the House.[1] At the state level, twenty-eight states either have or are planning to institute a greenhouse gas emission reduction strategy[2] (For example, Washington recently passed a law regulating carbon dioxide from new electric generation plants, which requires that 20 percent of the carbon dioxide from new plants either be taxed or be mitigated through offset projects.[3] Oregon passed a similar law in 1997[4]).

The magnitude of the CO_2 regulation risk faced by IPC and its customers depends on the carbon intensity of the portfolio. Portfolios with a heavy emphasis on carbon emitting resources face the risk of increased power supply costs. Accordingly, Idaho Power Company believes it is prudent to incorporate reasonable estimates for the cost of carbon dioxide emissions into the IRP resource modeling and analysis, and to thereby actively seek to lessen the Company's and customers' exposure to the financial risk associated with carbon emissions.

The base case scenario used in the IRP assumes a $12.30 per ton CO_2 cost for carbon emissions, beginning in 2008; scenario analysis was conducted using no cost and $49.21 per ton CO_2 as the boundary conditions. The imputed costs of carbon emissions used in the risk analysis are derived from Order 93-695 from the Oregon PUC (The OPUC order specified costs in 1990 dollars and the costs have been escalated to 2004 dollars for the IRP). While the OPUC order was the starting point for the CO_2 analysis, IPC also confirmed that these costs represent reasonable estimates of the risk that IPC and its customers face due to potential future regulation of carbon dioxide emissions.

The CO_2 costs used in the Idaho Power Company 2004 IRP are consistent with two other recent analyses in the region. First, in PacifiCorp's recent Integrated Resource Plan, PacifiCorp assessed the range of likely future scenarios of regulation of carbon emissions, and the associated costs of these emissions, and found that $8 per ton of carbon dioxide was a reasonable value to represent the likely cost of carbon emissions. Second, a recent draft California PUC report also assessed the range of likely future scenarios of carbon regulation, and the associated costs, and concluded that a reasonable estimate for carbon costs is a trend of $5 per ton CO_2 in the near term, $12.50 per ton CO_2 by 2008, and $17.50 per ton CO_2 by 2013.[5] Further, this draft report found that the range of carbon costs is from a low of about zero up to $69 per ton CO_2. Thus, both the base case scenario and the high and low scenarios included in Idaho Power Company 2004 IRP are consistent with these recent analyses.

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[1] "Bipartisan Group to Unveil House version of McCain-Lieberman Bill", Energy and Environment Daily, March 30, 2004. www.eenews.net.

[2] "Climate Change Activities in the United States: 2004 Update," Pew Center for Climate Change, March 2004 (www.pewclimate.org).

[3] Washington House Bill 3141, http://access.wa.gov/leg/2004/Apr/n200431_0700.aspx.

[4] Oregon House bill 3283, 1997, http://www.energy.state.or.us/siting/co2std.htm.

[5] Energy and Environmental Economics and Rocky Mountain Institute, *A Forecast of Cost Effectiveness Avoided Costs and Externality Adders*, prepared for the California Public Utilities Commission, January 8, 2004.

CO_2 Tax Risk

PV Power Supply Costs *(30 year, includes wind PTC)*

		P3	P6	P7	P8	P11
CO_2 $0 per ton		$6,530	$6,518	$6,213	$6,320	$6,197
CO_2 $12 per ton		$7,712	$7,935	$7,699	$7,920	$7,547
CO_2 $49 per ton		$11,256	$12,316	$11,979	$12,521	$11,624
Expected relative to Expected		$0	$0	$0	$0	$0
Low relative to Expected		-$1,182	-$1,417	-$1,486	-$1,600	-$1,350
High relative to Expected		$3,544	$4,381	$4,280	$4,601	$4,077
Weights						
CO_2 $0 per ton	30%					
CO_2 $12 per ton	50%					
CO_2 $49 per ton	20%					
Weighted Risk		$354	$451	$410	$440	$410

Dollars in Millions

Market Risk

Each of the five portfolios was evaluated with respect to its exposure to market sales and purchases. Each portfolio relies on the regional market for sales when Idaho Power has surplus energy and for purchases during the times when Idaho Power demand exceeds generation. The market risk is reported below:

Market Exposure Risk

PV Power Supply Cost *(30-year, CO_2 at $12 per ton, includes wind PTC)*		**P3**	**P6**	**P7**	**P8**	**P11**
NPV Base Portfolio Cost		$7,712	$7,935	$7,699	$7,920	$7,547
Market Sales ($ millions)		-$1,874	-$1,478	-$1,832	-$1,761	-$1,820
Market Purchases ($ millions)		$664	$1,030	$537	$707	$659
Net Purchases (Sales) ($ millions)		-$1,210	-$448	-$1,295	-$1,054	-$1,161
10% increase in power prices		-$121	-$45	-$130	-$105	-$116
10% decrease in power prices		$121	$45	$130	$105	$116
Expected relative to Expected		$0	$0	$0	$0	$0
Expected relative to 10% increase		-$121	-$45	-$130	-$105	-$116
Expected relative to 10% decrease		$121	$45	$130	$105	$116
Weights						
Expected	50%					
Increase in price	30%					
Decrease in price	20%					
Weighted Risk		-$12	-$4	-$13	-$11	-$12

Dollars in Millions

Because the resource planning criteria eliminate the monthly energy deficiencies, under no portfolios is Idaho Power Company a net importer of power. Under all portfolios, Idaho Power Company is a net exporter of power and Idaho Power Company and its customers benefit from regional market sales. Portfolio 7 has the greatest amount of market sales and therefore faces the greatest market risk. Portfolio 7 also has the most surplus capacity at the end of the planning period because the seasonal-ownership coal plant is not added until 2013.

Risk Analysis Summary

The five types of risk, capital risk, production tax credit risk, natural gas price exposure, CO_2 tax exposure, and market exposure, can be combined into one summary by adding the five values together. Net market sales are shown as a negative number indicating that market sales are expected to reduce the portfolio cost. In some cases, fuel price risk is shown as a negative number indicating a reduction in portfolio power supply costs. The other three risk categories are expected to increase the portfolio cost. A summary of the five types of quantitative risk is shown below:

Portfolio 11 dominates the other four portfolios with regard to the quantitative risk analysis. The Idaho Power Company analysis shows that Portfolio 11 fares the best when the market risk are combined. Idaho Power Company has selected Portfolio 11 to develop the Ten-Year and Near-Term action plans.

The Near-Term Action Plan is discussed in Chapter 8, but it is interesting to note that of the top five resource portfolios, four would have very similar near-term action plans. Three of the diversified portfolios, and the wind generation with natural gas backup would have very similar near-term action plans. The near-term action plan for the Portfolio 8, the portfolio that emphasizes coal-fired generation, would be significantly different. Even so, should coal-fired generation become more attractive, Portfolio 11 does include coal-fired generation and allows the proportion of coal-fired generation to be increased in future resource plans.

Risk Analysis Summary

PV Power Supply Cost *(CO_2 at $12 per ton, includes wind PTC)*

	P3	P6	P7	P8	P11
Portfolio Power Supply Cost	$7,712	$7,935	$7,699	$7,920	$7,547
Discount Rate Sensitivity	$80	$82	$70	$74	$69
Construction Risk	$88	$0	$55	$11	$43
Weighted CO_2 Risk	$354	$451	$410	$440	$410
Weighted PTC Risk	$158	$37	$37	$15	$56
Weighted Gas Price Risk	$44	$52	-$23	-$15	$16
Weighted Market Risk	-$12	-$4	-$13	-$11	-$12
Total of Weighted Risk Adjustments	$712	$618	$536	$514	$582
Total Risk Adjusted PPSC	**$8,424**	**$8,553**	**$8,235**	**$8,434**	**$8,129**

Dollars in Millions

Figure 15 Load Forecast Risk – High, Expected, and Low Growth Scenarios

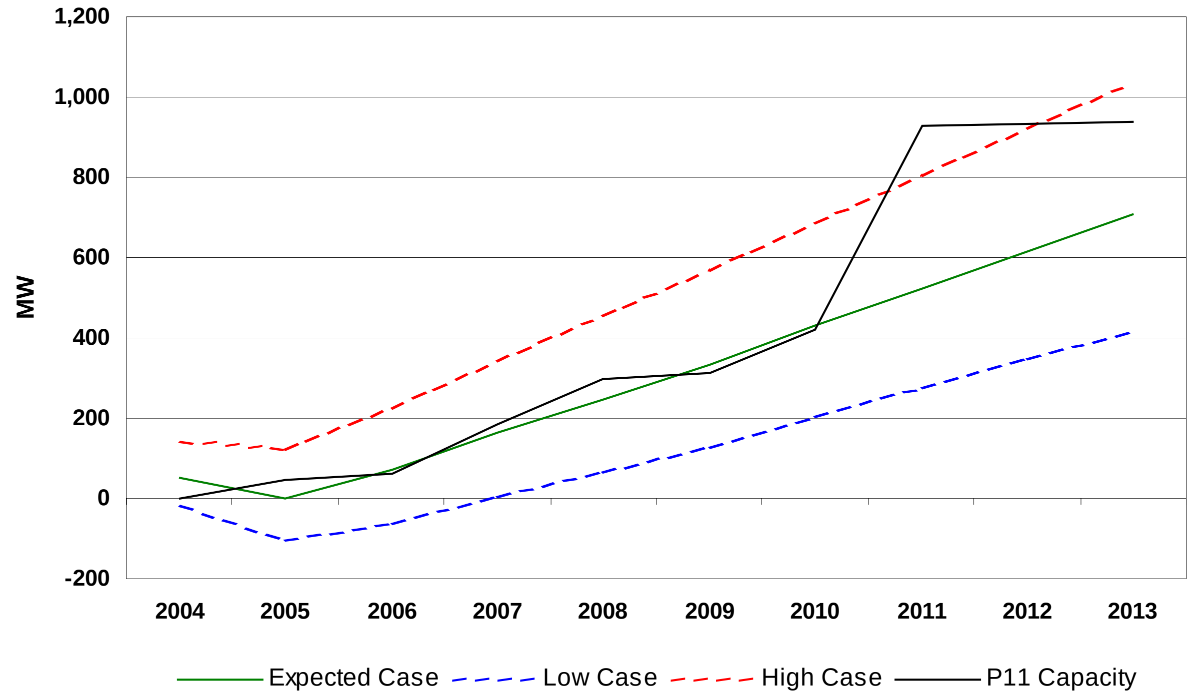


Figure 15 shows the load forecast risk under the high and low load forecasts that will be faced by adopting Portfolio 11. Portfolio 11 closely matches the energy capacity required to meet the expected load forecast during the early years of the planning period. As would be the case with any large resource, adding the 500 MW of coal-fired generation in 2011 leads to a temporary energy surplus during the time that Idaho Power Company receives the plant output. Idaho Power prefers that the 500 MW of coal-fired generation be a combination of smaller units such as two 250 MW units. Having the 500 MW of seasonal-ownership coal-fired generation be composed of smaller units gives greater online date flexibility as well as additional flexibility and reduced online risk when the 500 MW facility is fully operational. Idaho Power Company faced the same generation surplus issues in the past with the Bridger and Valmy plants and Idaho Power Company entered into term sales contracts until the native load growth required the plant output.

If actual customer load turns out to be either higher or lower than the expected load forecast, then the timing and size of the resource RFPs in Portfolio 11 can be adjusted to accommodate the realized customer load. Idaho Power Company anticipates some flexibility in both the RFP and the responses for the 88 MW combustion turbine. Idaho Power expects that the RFP will specify a range of turbine sizes similar to the Bennett Mountain RFP in 2003, perhaps up to 200 MW as in the Bennett Mountain RFP. The RFP flexibility allows the developers to respond to the RFP with their most cost effective proposals. Idaho Power Company expects to offer similar flexibility in the DSM and renewable RFPs as well.

Portfolio 11 has a diverse mix of generation resources equally balanced between renewable resources and traditional thermal resources. The qualitative risks associated with policy changes, resource timing, siting, and public acceptance are difficult to forecast. However, a diverse portfolio will have less exposure to qualitative risk than will a portfolio that is concentrated on one resource type or one resource strategy. The risk analysis supports the conclusion that Portfolio 11, with its blended approach, is well suited to meet the future resource needs of the Idaho Power Company customers. In summary, the advantages of Portfolio 11 are:

- Lowest risk-adjusted portfolio power supply costs
- Diversifies Idaho Power Company’s overall resource mix
- Positions Idaho Power Company to meet potential public policy changes (CO_2 tax and renewable portfolio standards)
- Reduces the resource commitment early in the planning period by closely matching resource additions to capacity needs

It is important to note that the final objective of the risk analysis is not to exactly quantify the risk associated with a portfolio. Instead, the risk analysis is designed to identify a portfolio that leads to ten-year and near-term action plans that are resilient to the different risks. The objective is to arrive at an Integrated Resource Plan that meets the projected needs of the customers, as well as a plan that can accommodate economic and political changes at the least cost to the customers and shareowners of Idaho Power Company. The action plans resulting from selecting Portfolio 11 are discussed in Chapters 7 and 8.

7. Ten-Year Resource Plan

Introduction

Portfolio 11 consisting of a diversified set of supply side resources plus 76 MW of demand response and 48 MW of demand-side energy management is selected as the preferred portfolio. Portfolio 11 adds approximately 800 MW of energy resources and over 900 MW MW of capacity during the ten-year planning period. The energy and capacity estimates include the demand-response programs.

Selecting Portfolio 11 provides Idaho Power Company with a schedule of planned events as outlined in Table 14 and Table 15. Idaho Power expects to use the Request for Proposals (RFP) process to acquire both supply-side resources and demand-side programs. RFPs for the first two resource additions, 200 MW of wind power and the 88 MW combustion turbine expansion will begin this fall. Also, Idaho Power Company intends to work with the Energy Efficiency Advisory Group (EEAG) to initiate the demand-side activities. Requests for Proposals for the other resources will follow throughout the early years of the planning period.

Table 14 Portfolio 11 – Ten-Year Resource Plan

Year	Activity
August 2004	1. 2004 Integrated Resource Plan submitted to the Idaho and Oregon Public Utility Commissions
Fall 2004	1. Idaho Power Company and Utility Commissioners communicate regarding IRP specifics and concerns 2. RFP issued for 200 MW wind 3. RFP issued for 88 MW peaking resource 4. File DSM results as a supplement to the IRP 5. File energy efficiency tariff rider in Oregon
2005	1. Demand-side measures designed in partnership with the Energy Efficiency Advisory Group and the Public Utility Commissions 2. RFP issued for 12 MW CHP 3. RFP issued for 100 MW geothermal 4. Utility partner for seasonal-ownership coal plant identified

Table 15 Portfolio 11 – Ten-Year Resource Plan *(Continued)*

Year	**Activity**
2006	1. CHP design work with successful bidders 2. 100 MW of wind generation online 3. 150 MW Borah-West transmission upgrade complete 4. Ongoing DSM programs 5. RFP issued for 500 MW seasonal-ownership coal-fired generation 6. 2006 IRP
2007	1. 12 MW CHP online 2. 88 MW Danskin expansion online 3. 100 MW wind generation online 4. 500 MW seasonal coal begin construction 5. RFP issued for 62 MW combined cycle gas turbine or distributed generation 6. Ongoing DSM programs
2008	1. 100 MW geothermal online 2. 100 MW proposed Borah-West transmission upgrade complete 3. RFP issued for 36 MW CHP 4. RFP issued for 150 MW wind 5. Ongoing DSM programs 6. 2008 IRP
2009	1. CHP design work with successful bidders 2. Ongoing DSM programs
2010	1. 36 MW CHP online 2. 150 MW wind online 3. 62 MW Combustion Turbine or peaking resource online 4. Ongoing DSM programs 5. 2010 IRP
2011	1. 500 MW seasonal-ownership coal-fired generation online 2. Ongoing DSM programs
2012	1. Ongoing DSM programs 2. 2012 IRP
2013	1. Ongoing DSM programs

Supply-Side Resources

The 2004 Integrated Resource Plan identifies approximately 800 MW of energy additions to the Idaho Power Company supply-side portfolio. Idaho Power Company intends to add 350 MW of wind generation, 100 MW of geothermal generation, 88 MW combustion turbine upgrade, and 62 MW of combustion turbines or distributed resources later in the time period. Idaho Power Company also plans to add 48 MW of generation from combined heat and power at some of its customer's facilities.

Idaho Power Company expects to add 500 MW of seasonal-ownership coal-fired generation later in the planning period in 2011. Idaho Power Company prefers that the seasonal-ownership coal-fired facility be composed of smaller individual units such as two 250 MW units for greater operational flexibility and reliability. In addition, the construction timing of a combination of smaller units may better coincide with customer load growth in the Idaho Power Company service territory.

Idaho Power Company faces some uncertainty regarding future PURPA generation. Idaho Power Company may need to revise the Ten-Year and Near-Term action plans should the quantity of PURPA generation significantly change form the 78 aMW assumed in the 2004 Integrated Resource Plan. Idaho Power Company anticipates that some large developments that may qualify for PURPA negotiations will be submitted as part of the Company's generation requests for proposals. Idaho Power Company will revisit the Ten-Year and Near-Term Action plans in future Integrated Resource Plans.

Renewable Energy

In 2003 Idaho Power Company hydro generation supplied 38 percent of the energy used by Idaho Power customers under low water conditions. By 2012, under normal water conditions, hydro generation will continue to supply about 38 percent of the energy used by Idaho Power customers.

Wind, geothermal, and other non-hydro renewable resources supplied a negligible amount of energy used by Idaho Power customers in 2003. Other than the Green Energy Program, Idaho Power had no specific non-hydro renewable energy purchases in 2003. Idaho Power Company intends to acquire 350 MW of wind generation and 100 MW of geothermal generation by 2012. By 2012, non-hydro renewable energy will supply 9 percent of the energy used by Idaho Power customers under normal renewable energy conditions.

Peaking Resources

The 2004 Integrated Resource Plan adds 939 MW of capacity additions to the resource portfolio. Idaho Power Company will add wind, geothermal, and thermal resources. The Idaho Power Company peaking capacity will be increased by an 88 MW combustion turbine upgrade. The most promising site appears to be an upgrade of the Danskin site with the addition of two combustion turbines, however other sites are also being considered. With the additional 88 MW, Idaho Power Company will have 338 MW of natural gas fired peaking generation.

The primary purpose of the combustion turbines is to provide the generation capacity necessary to meet peak-hour loads. However, Idaho Power Company has the option to operate the combustion turbines to meet monthly energy requirements within the operating limits of the facility permits. With the current and forecast natural gas prices, purchasing energy from the regional markets, up to the limits of the transmission system, will most likely be more economical than operating the combustion turbines as an energy resource. Idaho Power Company anticipates mainly operating the combustion turbines when customer load exceeds the combined capacity of the Company's other generation units and the transmission system.

Market Purchases

In 2003, under low water conditions, Idaho Power Company purchased 21 percent of the energy used by its customers on the regional energy markets. By 2012, under normal water and renewable conditions, purchased power is expected to supply only 4 percent of the energy used by Idaho Power Company customers. Summertime on-peak capacity purchases will still be necessary and Idaho Power expects to continue to use the full capacity of the transmission system to access regional power markets.

Idaho Power Company is taking steps to reduce the reliance on regional markets for energy purchases. Our regional trading partners sometimes offer term market purchases and exchanges and Idaho Power Company will continue to evaluate the regional market purchases and exchanges on a case-by-case basis. The 2004 Integrated Resource Plan anticipates that Idaho Power Company will continue to make summertime energy and capacity purchases of up to several hundred MWs to meet customer load during the early years of the planning period.

Transmission Resources

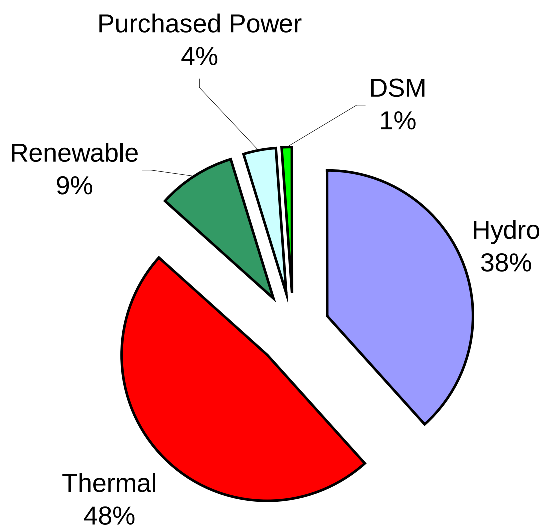
The additional generation will require significant upgrades to the backbone transmission system. Idaho Power Company has already begun the process to upgrade the Borah-West transmission path. It is anticipated that much of the renewable generation will be located in Eastern Idaho and that generation will require an improved Borah-West transmission path. Idaho Power Company intends to increase the capacity of the Borah-West transmission path by 150 MW in 2006 and Idaho Power Company has applied to increase the capacity by another 100 MW in 2008. The Borah-West upgrades are necessary to serve Idaho Power Company native load – either through resources identified in this Integrated Resource Plan or through additional imports from the east side. Additional upgrades to the Borah-West and Midpoint-West transmission paths may be necessary if more resources are added in Eastern Idaho or Wyoming.

The site of the proposed seasonal coal plant has not been identified so the exact transmission paths are unknown. It is likely that the seasonal coal plant will also require significant transmission upgrades and even though the exact paths are unknown, transmission cost estimates for upgrades were included in the analysis.

Demand-Side Management and Pricing Options

Idaho Power Company anticipates increasing the emphasis on demand-side programs during the planning period. By 2012, Idaho Power Company demand-side and peak-reduction programs are expected to supply approximately one percent of the customer energy requirement. The one percent is in addition to the effects of national energy measures. Figure 16 shows the 2012 energy sources assuming normal water and normal non-hydro renewable resource conditions.

Figure 16 Idaho Power Company 2012 Energy Sources



8. Near-Term Action Plan

Introduction

Customer growth is the primary driving force behind Idaho Power Company's need for additional resources. Population growth throughout Southern Idaho, and specifically in the Treasure Valley, requires additional measures to meet both peak and energy needs.

Over the past 85 years, Idaho Power Company has developed a blended portfolio of generation resources. IPC believes that a blended approach based on a portfolio of diverse resources is the most cost-effective and least-risk method to address the increasing energy demands of our customers.

Supply-side generation resources are likely to be the primary method to meet the increasing energy demands of Idaho Power Company customers. However, IPC customers have expressed an interest that all generation resources be financially, environmentally, and socially responsible. Renewable energy and demand-side measures are significant contributors to the resource portfolio selected in the 2004 Integrated Resource Plan.

Near-Term Action Plan

The Near-Term Action Plan presented in Table 16 is designed to accommodate resource uncertainty. During the Integrated Resource Plan Advisory Council meetings, several participants were concerned that wind resources, geothermal resources, demand-side measures, and combined heat and power resources may or may not meet the energy and capacity targets identified in the 2004 IRP. Idaho Power Company intends to acquire production resources in all four categories early in the resource plan. The energy and capacity values in future resource plans in 2006 and 2008 may be modified to reflect the actual production experience that Idaho Power Company gains with wind resources, geothermal resources, demand-side programs, and combined heat and power projects. Idaho Power Company intends to take an active role supporting the development of these resource options by acquiring production energy and capacity with an RFP process as part of the 2004 IRP.

Table 16 Portfolio 11– Near-Term Action Plan *(Present through 2006)*

Year	Activity
August 2004	1. 2004 Integrated Resource Plan submitted to the Idaho and Oregon Public Utility Commissions
Fall 2004	1. Idaho Power Company and Utility Commissioners communicate regarding IRP specifics and concerns 2. RFP issued for 200 MW wind 3. RFP issued for 88 MW peaking resource 4. File DSM results as a supplement to the IRP 5. File energy efficiency tariff rider in Oregon
2005	1. Demand-side measures designed and funded through Energy Efficiency Advisory Group and the Public Utility Commissions 2. RFP issued for 12 MW CHP 3. RFP issued for 100 MW geothermal 4. Utility partner for seasonal-ownership coal plant identified
2006	1. CHP design work with successful bidders 2. 100 MW of wind generation online 3. 150 MW Borah-West transmission upgrade complete 4. Ongoing DSM programs 5. RFP issued for 500 MW seasonal-ownership coal plant 6. 2006 IRP

Generation Resources

Thermal Generation - Baseload

Idaho Power Company intends to issue an RFP for approximately 12 MW of combined heat and power projects in early 2005. Various Idaho Power Company industrial customers have approached Idaho Power Company regarding combined heat and power projects. Idaho Power expects that design and construction of the projects will occur in 2005 and 2006, and the projects will be online beginning in 2007.

Idaho Power will need additional base-load generation to meet the energy demands of the new and existing customers. Idaho Power Company has not added a baseload generation facility since it acquired fifty percent ownership of the Valmy coal-fired generation plant in the mid 1980s. The 2004 Integrated Resource Plan identifies that the time has come to acquire additional base-load generation. Idaho Power intends to acquire 500 MW of coal-fired generation to be online in 2011. Idaho Power Company will explore the interest to share seasonal ownership of the facility with other utility partners. Idaho Power expects that a Request for Proposals for the coal-fired generation will be issued in 2006.

Thermal Generation - Peaking

Population growth in Southern Idaho is an inescapable fact and air conditioning is a common feature in most new construction. The Idaho Power Company summer peak continues to grow at approximately 80 MW per year. Idaho Power Company will need physical resources, such as the Bennett Mountain and Danskin power plants near Mountain Home, Idaho, to meet the energy demands of the additional customers. Idaho Power intends to issue an RFP for an 88 MW simple-cycle combustion turbine peaking resource in late 2004. The simple-cycle combustion turbine was selected because the upgrade provides additional peaking capacity at low capital cost and because of the short construction lead-time.

Renewable Energy

Idaho Power will continue its evaluation of renewable energy. In the 2002 IRP Idaho Power stated, "Idaho Power intends to dedicate up to $50,000 to explore the feasibility of constructing a pilot anaerobic digester project within the IPC service territory." In 2003 Idaho Power Company donated a $50,000 educational grant to the University of Idaho to study the development of methane digesters within the Idaho Power Company service territory and the State of Idaho.

Idaho Power will continue to fund education and demonstration energy projects with up to $100,000 of funding. One of the current projects is to support the Foothills Environmental Learning Center to be built on the north side of Boise just off 8th Street near Hull's Gulch. Support includes the installation of a 4.6 kW fuel cell and a 2.0 kW solar panel at the center. Other private supporters include Intermountain Gas, Boise Cascade Corporation, The Nature Conservancy, the Golden Eagle Audubon Society, and United Water. The 3300 square foot Foothills Environmental Learning Center will provide ongoing education to improve land management of the Boise foothills and the Boise Parks and Recreation Department will manage the center. Another planned project is to repair and upgrade the 15 kW demonstration solar energy project on the roof of the Idaho Power Corporate headquarters in downtown Boise.

Idaho Power Company's most significant new commitment to renewable resources is the intention to add a significant quantity of renewable energy to the company's generation portfolio. Idaho Power Company intends to issue Request for Proposals (RFP) for up to 450 MW of renewable resources. If the RFP process is successful, Idaho Power will add approximately 450 MW of renewable wind and geothermal resources to its generation portfolio.

Wind Generation

Idaho Power Company intends to issue an RFP for approximately 200 MW of wind generation in late 2004. The wind generation is expected to come online in 2006 and 2007. Idaho Power Company recognizes that wind generation has moved beyond the research and development stage and Idaho Power will incorporate wind energy into the generation portfolio as a production resource. Wind developers have indicated that there are several viable wind generation sites in Southern Idaho. Idaho Power Company will acquire wind generation up to a total of approximately 200 MW as part of the near-term action plan and 350 MW of wind generation as part of the ten-year action plant.

Portfolio 3, Wind with Back-up Gas Generation, scored well in the resource analysis. Depending on the actual performance of the wind generation in production in Southern Idaho, Idaho Power Company may increase the amount of wind generation in future resource plans.

Geothermal Generation

Idaho Power Company intends to issue an RFP for approximately 100 MW of geothermal generation in 2005. As with wind, Idaho Power Company recognizes that geothermal generation has moved beyond the research and development stage and Idaho Power will incorporate geothermal energy into the generation portfolio as a production resource. Geothermal developers have indicated that there are several viable geothermal generation sites in Southern Idaho. Idaho Power Company will acquire geothermal generation up to a total of approximately 100 MW as part of the near-term action plan. The 100 MW of geothermal generation is expected to be online in 2008. Depending on the success of the geothermal generation projects, geothermal generation may play a greater role in future resource portfolios.

Transmission Resources

The new generation resources proposed in the 2004 Integrated Resource Plan will require additional transmission resources. Idaho Power expects to construct additional transmission including a 150 MW upgrade to the Borah-West transmission path as part of the thermal and renewable generation plans presented earlier in this chapter. Idaho Power Company has filed for an additional 100 MW upgrade to the Borah-West transmission path as well. The Borah-West upgrades are necessary to serve Idaho Power Company native load either through additional generation in SE Idaho or additional east-side imports. Idaho Power Company will evaluate the transmission requirements of the proposed generation projects and weigh the transmission requirements in the bid evaluation process. However, the planned Borah-West upgrades that are necessary to integrate generation resources located on the eastern side of the service territory will also increase Idaho Power Company's ability to import power from markets east of Idaho.

Demand-Side Management and Pricing Options

Idaho Power Company intends to work with the Energy Efficiency Advisory Group and the Public Utility Commissions of Idaho and Oregon in 2005 to design and fund 48 MW of Demand-Side Management programs and 76 MW of Demand-Response programs. Idaho Power Company intends to file for an energy efficiency tariff rider with the Oregon PUC before the end of 2004.

Idaho Power anticipates that some of the Energy Efficiency and Demand-Response programs will be conducted through a competitive process using Requests for Proposals. Additionally, Idaho Power intends to have the effectiveness of the programs assessed using an independent evaluation process, again likely conducted using Requests for Proposals. Idaho Power Company expects that the energy efficiency and Demand-Response programs will come online starting in 2005 and continue throughout the planning period. Depending on the success of the DSM and Demand-Response programs, these programs may play a greater role in future resource portfolios.

Risk Mitigation

The Near-Term Action Plan is specifically designed to mitigate some of the risks discussed in Chapter 6. The Near-Term Action Plan has RFPs for renewable resources, combined heat and power, and demand-side programs early in the planning period. Idaho Power Company also plans to release an RFP for additional natural-gas fired generation in 2004. The RFPs reduce risk by acquiring a diverse mix of resources early in the planning period.

Although renewable resources and demand-side programs face no fuel price risk, there are other risks associated with these options. Wind and geothermal resources are unproven in Idaho. Idaho Power Company has received considerable interest from renewable resource developers, but until the responses to the RFPs are received, it is difficult to assess the real potential of the resources. Likewise with demand-side programs – until the responses to the RFPs are received, it is difficult to assess the real potential of the programs.

RFPs for the renewable resources and demand-side programs are planned for release in 2004 and 2005. Like the Bennett Mountain RFP in 2003, Idaho Power expects to issue the RFPs for a range of generation and Idaho Power will entertain flexibility from the developers for all resource types.

Idaho Power Company believes that it is imprudent to specify the exact the DSM programs at this time for two reasons:

1. The ongoing study of DSM potential in the Idaho Power service territory is not yet completed.
2. DSM program developers may indeed propose additional programs or changes to the programs identified in the DSM study.

Idaho Power Company analysts included DSM programs that represent a variety of customer segments to estimate the potential DSM savings. The actual quantity of energy savings will depend on the specific programs proposed as well as the performance of the vendors. Idaho Power Company believes that the DSM quantities identified in Portfolio 11 are reasonable targets and Idaho Power Company expects that DSM vendors will perform and meet the targets.

Idaho Power Company prepares an Integrated Resource Plan every two years. At the time of the 2006 IRP, Idaho Power Company will have additional information regarding renewable resources, demand-side programs, fuel prices, economic conditions, and load growth. The responses to the RFPs in 2004 and 2005 will greatly influence the resource quantities identified in the 2006 Integrated Resource Plan.

Resource planning is a continuous process that Idaho Power Company constantly works to improve. Idaho Power Company invited outside participation to help develop the 2004 Integrated Resource Plan. Idaho Power Company values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and the comments provided by concerned citizens and customers. Idaho Power Company prepares and publishes a resource plan every two years and expects that the experience gained over the next few years will lead to modifications in the ten-year resource plan presented in this document. Idaho Power looks forward to continuing the resource planning process with concerned parties.