Q. Please state your name and business address for the record.

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a Staff engineer.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Idaho Department of Water Resources from 1983 to 1994. In 1988, I received my Idaho license as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. During my employment at the IPUC, I have attended the 1995 annual regulatory studies program sponsored by the National Association of Regulatory Commissioners (NARUC) at Michigan State University, the 1995 Lawrence Berkeley Laboratory Advanced Integrated Resource Plan (IRP) Seminar, an advanced IRP course sponsored by EPRI entitled Resource Planning in a Competitive

Environment, and a 1998 workshop on Pricing and Restructuring Alternatives in a Changing Electric Industry sponsored by the New Mexico State University Center for Public Utilities. My duties at the Commission include analysis of utility rate applications, rate design, tariff analysis and customer petitions.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the adequacy of Idaho Power's long-term and short-term planning process, changes that I believe need to be made to the planning process, the role of IdaCorp's Risk Management Committee in the planning process, and recommendations on how the role of the Risk Management Committee should be changed.

Q. What are the Commission's current electric utility planning requirements?

A. Regulated electric utilities in Idaho are required by Order No. 22299 to prepare IRPs and file them biennially with the Commission. Integrated Resource Plans include the following three basic elements:

1. A summary of existing hydroelectric, thermal and Public Utility Regulatory Policy Act

(PURPA) generating resources, and a summary of contract purchases and exchanges.

2. A summary of the utility's present load situation and forecasts of possible future load requirements.

3. A discussion of the utility's plan for meeting all potential jurisdictional load over the planning horizon. The discussion should include references to expected costs, reliability, and risks inherent in the range of credible future scenarios.

Q. What is the purpose of an IRP?

A. The primary purpose of an IRP is to insure that the utility considers all alternatives, both demand side and supply side, for meeting expected loads in the future at the lowest cost. The process of preparing an IRP also insures that the full costs and risks associated with all alternatives are considered. The process requires that the utility seek input from its customers, interested parties and from the Commission Staff. The process itself and the submission of the written plan as an end product, document the utility's planning and provide the Commission and the public a window into the utility's planning process as well as a forum for providing input.

Q. Can a utility deviate from its IRP?

A. Yes, in fact, a utility is expected to deviate from its IRP when circumstances warrant. The Commission, in Order No. 25260, adopted a policy regarding integrated resource planning in which it stated the following:

> The requirement for implementation of a plan does not mean that the plan must be followed without deviation. The requirement of implementation of a plan means that an electric utility, having made an integrated resource plan to provide adequate and reliable service to its electric customers at the lowest system cost, may and should deviate from that plan when presented with responsible, reliable opportunities to further lower its planned system cost not anticipated or identified in new existing or earlier plans and not undermining the utility's reliability. . . . the filing of the plan does not constitute approval or disapproval of the plan having the force and effect of law, and deviation from the plan would not constitute violation of the Commission's orders or rules. The prudence of a utility's plan and the utility's prudence in following or not following a plan are matters that may be considered in a general rate proceeding or other proceeding in which those issues have been noticed.

The IRP represents a utility's long-term plan for meeting load. Currently, utilities are required to use a 10-year planning horizon.

Q. In Idaho Power's most recent IRP, how did the

Company indicate it would meet short-term deficits?

A. In Idaho Power's most recent IRP, the 2000 IRP filed in June 2000, the Company indicated that it intended to meet short-term deficits by purchasing from the market. The Company planned to have sufficient resources in place to meet load under median water conditions, but intended to meet deficits under low water conditions with wholesale market purchases.

Under median water conditions and expected loads, the 2000 IRP showed deficits beginning in the year 2000 of approximately 142 average MegaWatts (aMW) in July, 86 aMW in August, and 88 aMW in December. Without the addition of any new generation resources, deficits in these months were expected to grow, and deficits in other months were expected to appear as loads grew. Exhibit No. 101 shows graphically the monthly energy surplus/deficiency through 2010. To fully satisfy expected deficits under median water conditions, Idaho Power planned to purchase up to 250 aMW of energy in July and August, and 200 aMW of energy in November and December.

Q. If Idaho Power planned to rely on the market even under median water conditions, what were its plans under low water conditions?

A. Under low water conditions, the Company planned to rely on the market to an even greater extent. Under the low water scenario, the IRP projected substantial deficits to begin immediately in the summer and winter months. Exhibit No. 102 shows the monthly energy surplus/deficiency under low water conditions. A deficit of as much as 334 aMW appears as early as July 2000.

The monthly peak hour surplus/deficiency graph also reveals how dependent Idaho Power was expected to be under low water conditions as shown in Exhibit No. 103. For the monthly peak hour, Idaho Power expected to be deficit almost all of the months of the year.

Under low water, even with the purchase of 250 aMW in the summer (July and August) and 200 aMW in the winter (November and December), the Company still projected deficits as high as 264 aMW in May of 2000. Exhibit No. 104 shows the Company's expected monthly deficits, including planned seasonal purchases and new resource additions.

Q. How did the low water scenario in Idaho Power's IRP compare to what actually happened during the past year?

A. Exhibit No. 105 compares actual surpluses and deficits from June 2000 through May 2001 to the low water scenario in the IRP. As the exhibit shows, deficits in five of the twelve months were even greater than expected under the low water scenario.

Q. It seems that Idaho Power's own IRP indicated the degree to which the Company might have to rely on the market this past year. Why then did Idaho Power incur such high purchased power costs?

A. The level of reliance on the market during the past year was, for the most part, expected given the water conditions. Some months showed deficits even greater than predicted under a low water scenario, while in some months, water conditions were above the low water condition and thus showed smaller deficits. What was not expected, however, were the extremely high market prices. The substantial planned reliance on the market combined with the extremely high prices led to higher than anticipated purchased power costs.

Q. How did Idaho Power respond to the high market prices of the past year?

A. The Company responded in several different ways. First, Idaho Power implemented buy-back programs for their irrigation customers and for Astaris, their largest industrial customer. In addition, the Company made a decision to construct 90 MW of new gas-fired generation at Mountain Home. Finally, the Company leased 25 MW of diesel-fired mobile generators and considered plans to lease two additional 25 MW increments of mobile generation.

Q. How did Idaho Power evaluate these resources and programs?

A. For the most part, Idaho Power compared the estimated costs of these resources and programs to the prices they otherwise expected to pay to acquire power from the market.

Q. Do you think Idaho Power's evaluations were appropriate?

A. In most cases they were, but in some cases I think more complete evaluations should have been done. For example, the irrigation buy-back program is only intended to last for the current season, so a comparison to expected market prices was reasonable. Similarly, the mobile generators have short-term leases that expire at the end of the summer. The Astaris buy-back is a two-year agreement, so a comparison with market alternatives is possible but more difficult. The Mountain Home project, on the other hand, is a project with an expected life of 30 years. A comparison to current market prices is not sufficient to determine the long-term cost effectiveness of the project. As a long-term resource, it should be compared to other long-term resource alternatives.

Q. How well do the alternatives selected by Idaho Power – i.e., irrigation buy-back, Astaris buy-back, Mountain Home generation project, and mobile generators – reduce the Company’s exposure to the wholesale market through the end of this year?

A. Under currently anticipated water conditions, the combination of these alternatives should enable Idaho Power to meet loads through March 2002 with no additional market purchases necessary, except for a small 37 aMW deficit during heavy load hours in December.

Under a worst case water scenario, deficits of 151 aMW in December, 80 aMW in January and 24 aMW in March would be possible without the purchase of additional energy or the addition of new resources.

Q. Do you think the experience of the past year indicates a weakness in the IRP planning process?

A. Yes, in some ways. The IRP process is perhaps more important than ever now that utilities are again faced with acquiring new resources and the risks of simply relying on the market have become evident. However, the IRP process was never intended to be a short-term planning tool. While utilities are expected to deviate from the IRP when necessary, there still must be a short-term planning process to guide decision making for such deviations. Without a short-term plan or a well defined process, the utility is put in a position of having to take quick actions and make emergency decisions. It can subsequently be difficult for both the utility and the Commission to assure ratepayers that prudent decision making occurred. Time constraints associated with planning and implementing new programs or in acquiring new resources can narrow the field of possible options. In addition, sometimes there is no assurance that the resources or programs chosen are necessarily the best when the primary basis for comparison is whether they are less costly than relying on the market. Customers and the Commission deserve some assurance that a full menu of options is considered, and that even short-term decisions are in the long-term interests of ratepayers.

One example of this was the Company's decision to pursue the Mountain Home generation project. Idaho Power did not identify the need for the project until early this year, and quickly decided to go ahead with it in a matter of weeks. Construction began on the project in June. While the project may be the best alternative for the Company, which may deserve to be commended for getting the project underway quickly, the Commission expressed concern about the lack of a comparison to other alternatives. Consequently, the Commission approved rate-basing the project but declined to approve a specific amount to be recovered in rates. Reference Order No. 28773.

Q. Do you believe any changes need to be made in the IRP planning process?

A. Yes. When the rules for IRPs were implemented, I do not believe anyone expected changes in market or natural gas prices to take place at the speed and to the degree they have recently. A two-year planning cycle is too long if a utility uses the full two years to completely overhaul the previous IRP. Integrated resource planning should be an ongoing process, not an effort to produce a final document. Integrated resource planning should not stop after completion of one plan and start up again prior to preparation of another. The plan, once submitted, should simply be a reflection of that continuing process. A two-year interval may still be reasonable for reporting the utility's planning activities to the Commission, however.

In addition, Idaho Power must incorporate market uncertainty into its IRP analysis. It is no longer reasonable to assume that market resources are unlimited and readily available at prices no higher than the marginal cost of new generation. Reliance on the market carries substantial risk. As more and more utilities have developed a dependence on the market in recent years, this risk has increased. What may have seemed like a reasonable level of planned reliance on the market just two years ago may no longer be reasonable. It has become more important to acknowledge that market prices are uncertain and perhaps less attractive than building new generators or acquiring long-term contracts for output from specific plants.

Finally, a fresh look at demand side alternatives is warranted. As market prices have increased, more and more demand side programs have become cost effective. Idaho Power should continue to support regional conservation efforts through the Northwest Energy Efficiency Alliance and proceed in developing a comprehensive Demand Side Management Program as directed by the Commission's Order No. 28722. As the past year has shown, quick implementation of various short-term demand reduction programs can be one of the most effective ways to respond to supply shortfalls and extremely high market prices. It is important to develop some experience with these types of demand side programs so that they can be rapidly deployed whenever needed. The Company should have an arsenal of programs “on the shelf” so that it does not need to devise new programs and strategies each time the need arises.

Q. What other changes do you recommend?

A. I recommend that Idaho Power consider abandoning median water planning and either move closer to critical water planning or re-establish a planning reserve.

Q. Please explain the difference between median water planning and critical water planning.

A. Median water planning means that the Company plans to have enough resources available under median water conditions to meet its expected native load on a monthly basis. A median water condition is that which represents the average condition over many years (a 50-year average in Idaho Power’s case). By definition then, above median conditions can be expected to occur in half of the years, and below median conditions can be expected in the remaining half. Consequently, Idaho Power currently plans to meet its load with its own resources or long-term contracts every month in half of the years, but must rely, at least to some extent, on spot or short-term market purchases to meet load during the other half of the years.

Critical water planning means that the Company would plan to have enough resources available under critical water conditions to meet its expected native load. Critical water conditions reflect the lowest consecutive 18-month period on record. A utility that planned to meet load under critical water conditions could meet load with its own resources for an extended period of time, but would not necessarily be able to meet load all of the time in every month.

Q. On what basis does Idaho Power plan?

A. Idaho Power has always planned using median water assumptions. Many other utilities in the region plan based on a critical water planning criterion.

Q. Do you believe Idaho Power should continue to plan based on median water?

A. No, not unless the Company reestablishes a planning reserve. Median water planning may have been acceptable when the availability and price of market resources were reasonably predictable. However, as we have seen in the past year, the price and availability of market resources can be extremely volatile. In the past, it was assumed that reliance on the market carried little risk, and that prices would not rise above the marginal cost of new generation. The experience of the past year has demonstrated that reliance on the market can expose ratepayers to considerable risk.

Q. In the direct testimony of Idaho Power witness Gale, he states that he believes that the Company's 2002 IRP should address in detail the issue of whether or not it is time to change the median water planning assumption for planning purposes. Do you agree?

A. I agree that the issue should be examined. In fact, I think that such an examination should begin immediately.

Q. Besides moving closer toward critical water planning, are there other ways to accomplish the same thing?

A. Yes, Idaho Power could establish a planning reserve. A planning reserve simply means that the Company would plan to have an increment of generating capability above that required to meet expected loads under median water conditions. A planning reserve insures that extra resources are available in the event of poor water conditions, higher than expected load growth, or other planning inaccuracies. Prior to 1995, Idaho Power maintained a six-percent planning reserve. Ironically, that reserve was eliminated, in part I believe, because of the readily available market resources that the Company believed it could call upon when needed.

Q. What would be the effect of either moving toward critical water planning or establishing a planning reserve?

A. The effect would be an increase in the amount of generation available from Idaho Power's own system. Thus, under low water conditions or during peak load periods, Idaho Power would be less reliant on the market. Having more system resources available would, of course, increase the revenue requirement used to set base rates, but it would reduce the Company's exposure to the high prices and volatility of the market. Staff recommends that the Company complete an analysis to determine what water conditions or planning reserve is appropriate. Such an analysis should include a comparison of the costs and benefits of having varying levels of excess generation available. I am not suggesting that Idaho Power eliminate its reliance on the market. I am only recommending that the level of reliance be reevaluated given recent market volatility. Idaho Power has relied on regional diversity exchanges for years to take advantage of seasonal differences in loads, and should continue to do so.

Q. What process does Idaho Power follow for short-term planning?

A. It appears that the short-term planning process is not nearly as well defined as the long-term process and that it depends somewhat on the circumstances. When issues arise, those Company personnel most closely associated with the issue perform the analysis, complete the planning and carry out necessary actions. Decisions about how to proceed however, appear to be made primarily by the Risk Management Committee. For example, when Idaho Power was faced with extremely high market prices and poor water conditions this past winter and spring, the Committee made decisions about which demand and supply side alternatives to implement. Detailed program and project plans were made by Idaho Power staff.

Q. Who are the members of the Risk Management Committee, and what are their positions and responsibilities within Idaho Power and IdaCorp?

A. The Risk Management Committee is made up of the following members:

Darrel Anderson	Vice President Finance, Treasurer, Idaho Power Company and IdaCorp
Jan B. Packwood	President and Chief Executive

Officer, Idaho Power Company and IdaCorp

Richard Riazzi — Senior Vice President, Generation and Marketing, Idaho Power Company and IdaCorp

J. LaMont Keen — Senior Vice President, Administration and Chief Financial Officer, Idaho Power Company and IdaCorp

Jim Miller — Senior Vice President, Delivery, Idaho Power Company

Robert Stahman — Vice President, Secretary and General Counsel, Idaho Power Company and IdaCorp

John Prescott — Vice President Generation, Idaho Power Company

Randy Hill — President and Chief Executive Officer, Ida-West Energy

An organizational chart showing the composition of the Risk Management Committee is attached as Exhibit No. 106.

Q. What is the purpose of the Risk Management Committee?

A. The purpose of the Risk Management Committee is to maintain general oversight over all of IdaCorp's commodity trading and financial risk management operations. As outlined in IdaCorp's Risk Management Policy, the primary role of the Committee is to make decisions regarding trading activities. The Risk Management Policy does not outline any responsibilities of the Committee with regard to acquisition of new generating resources or implementation of short-term demand side measures to meet load.

Q. Based on your investigation, does the Risk Management Committee restrict its role to only that outlined in the Risk Management Policy?

A. No, I believe the Risk Management Committee has taken on a greatly expanded role. I believe the original role of the Committee was to make decisions about market transactions in order to manage risk to IdaCorp shareholders. In fact, the Risk Management Committee was originally formed in 1996 in response to the Company's decision to enter into the non-regulated speculative commodity trading business. However, a review of the meeting minutes of the Committee over the past year shows that the Committee has now evolved into a decision making body for demand side and asset acquisition decisions, such as how Idaho Power Company should respond to meet short-term deficits and to minimize exposure to extremely high market prices. In addition to the traditional acquisition of energy from the market, the Risk Management Committee considers alternatives to market purchases, such as voluntary load reduction programs and temporary generation resources. For example, based on its meeting minutes, the Committee appeared to make final decisions about whether Idaho Power should proceed with the Astaris buy-back, the irrigation buy-back and the installation of mobile generators. The Committee did not appear to be involved in the selection of the Garnet Project or the Mountain Home Project as long-term future Company resources.

Q. Do you believe that it is appropriate for the Risk Management Committee to take on this expanded role?

A. No, I do not. I believe that the Risk Management Committee, given its apparent expanded role and the composition of its membership, has created the potential for serious conflicts of interest. What may be best for the shareholders of IdaCorp may not be what is best for ratepayers of Idaho Power Company. Because the Committee is composed of some members who are not officers of Idaho Power, and because the Committee answers to the Board of Directors of IdaCorp, its first allegiance is to its shareholders. Consequently, I believe it is possible that its decisions are not always in the best interests of ratepayers.

Q. Can you give an example of a conflict of interest?

A. Yes, I can. Idaho Power's decision to lease mobile generators was made by the Risk Management Committee. While I am not judging the prudence of that decision here, I am suggesting that the final decision to proceed should not have been made by the Committee. Most of the members of the Committee are officers of both Idaho Power Company and IdaCorp, but some are officers of only one. The president of Ida-West for example, should not be involved in decisions about acquisition of new generation by Idaho Power, even if the generation is only temporary. Ida-West is an unregulated subsidiary of IdaCorp whose business is building and operating new generation projects. In theory, their project proposals are supposed to compete with Idaho Power's own self-build options.

Other situations could exist where the Risk Management Committee may be willing to commit shareholders to paying ten percent of increased power supply costs as passed through by the PCA, in exchange for the opportunity for shareholders to earn a much greater unregulated return. A decision to rely on the spot market instead of a term transaction could be one example of such a conflict. If the decision were made by Idaho Power, keeping the interests of ratepayers foremost, a different decision might have been made.

Q. What steps do you believe should be taken to eliminate this possible conflict of interest?

A. First I believe Idaho Power should consider reestablishing a planning department within the Company.
The planning department would then have primary responsibility for both short-term and long-term planning. The planning department would also have more influence in planning decisions made on behalf of ratepayers.

Second, I believe that the Risk Management Committee should be restricted to making decisions only about the non-regulated affairs of IdaCorp. Idaho Power Company and its own officers and employees should have sole responsibility for making decisions regarding the Company’s regulated business. Idaho Power Company can then make decisions that it believes are in the best interests of its ratepayers. Idaho Power Company may wish to form its own advisory committee, but it should be completely internal to Idaho Power so that the interests of ratepayers are paramount. IdaCorp can continue to have its own Risk Management Committee and make decisions that it believes are in the best interests of its shareholders.

Q. Has Idaho Power indicated any plans to reorganize the Risk Management Committee?

A. Yes. Idaho Power has indicated that it and IdaCorp Energy (formerly IdaCorp Energy Solutions) are currently in the final stages of executing the separation of IdaCorp Energy from Idaho Power described in the Company's application in Case No. IPC-E-00-13. In conjunction with that separation, IdaCorp, Idaho Power and IdaCorp Energy are moving to restructure and separate the Risk Management Committee into more than one committee to ensure compliance with all codes of conduct and eliminate any duplication of functions. So far, Idaho Power has indicated that there will be two separate risk management committees: one for IdaCorp Energy and one for Idaho Power Company. Only one person — J. Lamont Keen, Idaho Power CFO and Senior Vice President of Administration — will be a member of both committees. John Prescott, Idaho Power Vice President of Generation, will chair the Idaho Power Risk Management Committee.

Q. Will this proposed split and reorganization of the Risk Management Committee alleviate your concerns about possible conflicts of interest?

A. Yes, I believe that it will alleviate my concerns with regard to conflicts of interest. However, I still recommend that Idaho Power consider reestablishing a planning department within the Company.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.