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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE EVANDER ANDREWS POWER PLANT	)	**CASE NO. IPC-E-06-9**

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

OCTOBER 10, 2006

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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 became licensed in Idaho as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. My duties at the Commission include analysis of utility applications and customer petitions.

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

A. There are three primary purposes of my testimony:

1) To address whether Idaho Power has demonstrated a sufficient need for a new

gas-fired peaking plant,

2) To address whether there are other, better alternatives to meeting future load than building a new generating plant, and

3) To address whether Idaho Power conducted a fair Request for Proposals (RFP) process and chose the best proposal.

Q. Please summarize your testimony.

A. My testimony begins by reviewing Idaho Power's 2004 IRP, which is the Company's basis for contending that it needs to acquire a gas-fired peaking plant. I also look at the 2006 IRP to see whether changes in loads, resources, fuel prices and other factors since the 2004 IRP still support a new gas peaking plant. Based on my reviews, I conclude that a gas peaker is needed.

Next, I discuss a variety of other options for addressing Idaho Power's peak loads, including non-Company-owned generation, conservation, demand response, transmission upgrades and others. I conclude that while these are viable alternatives, they cannot be relied on exclusively, and should continue to be pursued in conjunction with a new gas-fired peaking plant.

Next, I review the RFP process followed by Idaho Power. I discuss the method used to evaluate bids and address the price and non-price differences between the

two top-ranked proposals. I conclude that Idaho Power has not provided sufficient justification for selecting a project that is approximately $11 million more costly than the second place proposal, and I recommend that this difference in cost not be allowed into rate base in the future.

Finally, I discuss the proposal selected by Idaho Power. I recommend that only the project contract amount of $49.999 million be accepted at this time, and that all additional amounts spent on the project, including transmission, be subject to future audit and prudence review.

Q. Because your testimony is lengthy, please provide a table of contents for the aid of readers.

A. A table of contents is provided below:

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BACKGROUND

Q. What is Idaho Power seeking in its Application in this case?

A. On April 14, 2006, Idaho Power Company filed an Application for a Certificate of Public Convenience and Necessity to construct a new generating plant at the site known as the Evander Andrews Power Complex near Mountain Home, Idaho. Idaho Power requested that the Commission issue an Order granting a Certificate of Public Convenience and Necessity to construct the Project with an upper limit of $60 million allowed for the Company's investment in the Project, excluding transmission costs and subject to adjustment for legally-required changes and material changes in assumed escalation rates not foreseen at the time of the Application. Idaho Power also requested that the Order note that, in the ordinary course of events, Idaho Power can expect to rate base the prudent capital costs for this Project and to recover prudent fuel costs in the Company's Power Cost Adjustment mechanism.

NEED FOR POWER

Q. What is the basis for Idaho Power's request to construct a new generating plant?

A. Idaho Power maintains that its decision to construct the new generating plant is based on its 2004 Integrated Resource Plan (IRP). The IRP process evaluated the Company's future loads and resources and evaluated various options for meeting projected loads. The options for meeting load include: the purchase of power from the

wholesale market; the acquisition of additional generating resources; the implementation of pricing options; and/or implementing demand-side management programs. In short, the IRP is a planning process on how Idaho Power intends to meet its statutory obligations to serve its customers' loads.

Q. According to the 2004 IRP, what is Idaho Power's strategy for meeting future loads?

A. Idaho Power's strategy for meeting future load was described in the 2004 IRP as follows:

Fall 2004

- Issue an RFP for an 88 MW combustion turbine peaking resource (the proposed Evander Andrews plant in this case)
- Issue an RFP for a 200 MW wind 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 Public

Utility Commissions

- Issue an RFP for a 12 MW Combined Heat and Power (CHP) resource
- Issue an RFP for a 100 MW geothermal resource

For the most part, Idaho Power has followed the plan as set forth above, although it has deviated somewhat. The RFP for an 88 MW combustion turbine, the subject of this case, was delayed until March 2005 rather than being issued in the Fall 2004. The RFP for a wind resource was issued in December 2004, and was scaled back to 100 MW due to the unexpected influx of PURPA wind projects. An RFP for 12 MW of CHP has been delayed indefinitely, and the RFP for the geothermal resource was not issued until June 2006.

Q. Do you believe that it is appropriate for Idaho Power to base the need for a new peaking plant on its 2004 IRP?

A. At the time the Company began the RFP process for a new peaking resource, the 2004 IRP was the best information available to assess existing resources, forecasted loads and potential new resource options. However, because the 2006 IRP has just been completed, I believe that the need for the plant must also be further evaluated using the most up-to-date information available. Without a doubt, changes have occurred since the 2004 IRP

was prepared. Load forecasts have been revised, fuel costs have increased and new resource costs have been updated.

Q. Do you agree that the 2004 IRP demonstrates a need for the Evander Andrews project?

A. Yes, the 2004 IRP shows peak hour deficits in the months of May-September and November-December in every year of the planning period under 90th percentile water and 70th percentile load conditions (the conditions adopted by Idaho Power for peak capacity planning). See Exhibit No. 101. Even under median water and load conditions, the Company projects deficits of approximately 200 MW in the July-August time periods. See Exhibit No. 102. When it was assumed that power would be imported subject to the limits of Idaho Power's transmission capacity, the analysis shows peak hour deficits beginning in the summer of 2006 and growing rapidly thereafter. See Exhibit No. 103.

Q. By the time this testimony is filed, Idaho Power will have submitted its 2006 IRP for Commission approval. What does the draft 2006 IRP show with regard to Idaho Power's need for peaking resources?

A. The addition of the Bennett Mountain plant, a revised load growth forecast, and the impacts of peak load reduction DSM programs have been included in the new load-

resource balance. In addition, the analysis assumes that the proposed new Evander Andrews plant is approved. Exhibit No. 104 indicates that under the planning criteria used to evaluate peak-hour conditions, deficiencies exist during summer months throughout the planning period. Summer deficiencies from 2006-2010 vary between 350 to 400 MW even with the assumed addition of the new Evander Andrews plant in April 2008 and the expansion of the Shoshone Falls Project in 2010. For the remainder of the planning period, deficiencies in July increase from 450 MW to 1,800 MW in 2025.

Even with the recent addition of the Bennett Mountain plant, the assumption of the new Evander Andrews plant and the implementation of new DSM programs, the Company's most recent load-resource balance still demonstrates an inability to meet peak-hour loads in the summer and winter beginning in 2009.

Q. What does the preferred resource portfolio consist of in the Draft 2006 IRP?

A. Over the next 10-year time horizon, the preferred resource portfolio consists of a blend of wind, geothermal and CHP through 2012, followed by increased transmission capacity, a pulverized coal plant and a coal-fired integrated gasification combined cycle (IGCC) plant in the 2012-2017 time frame. The entire resource

portfolio is summarized in Exhibit No. 105.

Q. Are there any gas-fired peaking plants included in the preferred portfolio in the 2006 IRP?

A. No, there are none. In the draft 2006 IRP, Idaho Power's existing gas-fired peaking resources at the Evander Andrews Power Complex and the Bennett Mountain facility continue to provide approximately 250 MW of peaking resource capacity. Beginning in 2008, if approved, the new peaking resource at the Evander Andrews Power Complex (the unit for which Idaho Power is seeking approval in this case) will contribute approximately 170 MW of additional gas-fired peaking capacity, bringing the total gas-fired peaking capacity to approximately 420 MW. The CHP called for in the plan is likely to be gas-fired because the projects would presumably be located at industrial facilities.

The four finalist portfolios selected for more detailed risk analysis in the current draft of the 2006 IRP contain limited amounts of natural gas-fired generation. With the possible exception of combined heat and power (CHP) projects, which are likely to be natural gas fired, there is only one natural gas fired resource in the four portfolios. Finalist portfolio F-3 calls for a 170 MW combustion turbine in 2018. The preferred portfolio, F-2 does not include any resources specifically

identified as natural gas-fired, however, the portfolio includes 150 MW of CHP.

Q. If the 2006 IRP analysis were to be repeated, this time assuming that the Evander Andrews project is not already part of the existing resource portfolio, would a natural gas fired peaking plant be selected?

A. In response to production requests (Staff request No. 95), Idaho Power states that it is almost certain that a gas fired peaking plant would have been selected as part of the preferred portfolio. The Company cited its continued growth in summertime peak-hour loads and concluded that it needs either generation resources internal to its system or additional firm transmission capacity to markets with availability of firm summertime peak-hour energy.

Although Idaho Power may be correct in its belief that a gas fired peaking plant would be selected, the Company has not supported its belief by providing any analysis. Without any analysis, there is no way to verify whether a gas fired peaking plant would, in fact, still be selected.

Current gas prices, and those assumed in the 2006 IRP, are considerably higher than was assumed in the 2004 IRP. Consequently, IRP analysis today is much less likely to select gas-fired plants due to high fuel costs

and high fuel price volatility as evidenced by the fact that there are no gas-fired facilities in the preferred portfolio in the 2006 IRP.

Transmission Constraints

Q. What does the 2006 IRP analysis show with regard to the Company's ability to import power into its system in order to meet peak hour deficits?

A. Exhibit No. 106 indicates the amount of the peak hour deficit that cannot be imported from the Pacific Northwest over the existing transmission system based on peak-hour planning criteria. In this analysis, a deficiency exists in July 2007 due to the postponement of the proposed Evander Andrews project. Beginning in 2009, long-term transmission deficiencies occur in summer months and are expected to grow to approximately 1,550 MW by 2025.

The durations of Idaho Power's northwest transmission constraints are very limited, amounting in some cases to relatively few hours during the months. Although these hours seem fairly minimal, the consequences of the transmission constraints during these hours could be severe. Unless some other means could be found to either reduce peak hourly loads or increase generation, load curtailment would be necessary.

Q. Given Idaho Power's load-resource balance under

various water and load conditions, and its transmission constraints that limit its ability to import power during critical times of the year, do you believe that a gas-fired peaking plant is necessary?

A. Yes, I do. Without it, I believe there could be times when load could not be met, either with Idaho Power's own resources or with resources from outside its system.

OTHER RESOURCE ALTERNATIVES

New Customer-Owned Generation

Q. Are there customer-owned generation alternatives to the proposed Evander Andrews plant?

A. Possibly. One alternative would be to make a firm wholesale purchase or exchange involving an existing resource located within Idaho Power's control area. Except for PURPA projects, which I will discuss next, these types of resources are generally few and far between. **This section (Pages 13 to 15) of Staff's direct testimony contains confidential information subject to protective agreement. This section is attached as Confidential Exhibit No. 114.**

PURPA QFs

Q. Do you believe that more PURPA QFs could satisfy Idaho Power's need for new peaking generation?

A. Nearly all of the recent PURPA development has been small wind projects. It is unknown how much additional capacity might be developed and when such development might occur. There is currently a moratorium on development of new wind QFs larger than 100 kW until wind integration issues can be resolved (Order No. 29839, Case No. IPC-E-05-22).

Because nearly all new QFs are wind projects, however, it is unlikely that they could prove to be an acceptable replacement even if they could be timely developed. Wind generation is intermittent, thus there is no guarantee that the generation would be available during the peak hours when needed. I do not believe that PURPA QFs, especially wind, are well suited to meet the extreme peaking needs of Idaho Power.

Market Purchases

Q. Are market purchases a reasonable alternative for meeting future peak loads?

A. According to Idaho Power, it may be possible to purchase a custom-made product from a marketer that provides structured products, but such a purchase would require transmission from Mid-C across one or more of the Bonneville Power, PacifiCorp, Avista or NorthWestern transmission systems, in conjunction with transmission across Idaho Power's transmission system from the Hells Canyon Complex to its load center. Because one or more of these paths are subject to congestion, energy purchased at Mid-C cannot be used at all times to meet the load requirements of Idaho Power. In addition, because custom-made products provide a significant amount of optionality, they carry a significant premium to fixed price term products as well as credit exposure to the selling party according to Idaho Power.

Another alternative would be to make firm wholesale purchases and to acquire the necessary transmission to deliver the energy to the east side of Idaho Power's system. In fact, as stated in Company witness Said's testimony, Idaho Power did just that for the summer of 2007 to meet heavy load hour requirements. Idaho Power made a 50 MW market purchase including the

associated transmission. Although such purchases may be available from time to time, I do not believe it would be wise to rely on them indefinitely to meet peak hour needs, especially during a time when surplus generation may be in short supply. Moreover, firm wholesale purchases delivered to the east side of its system use an increment of import capacity that, because it is being used for a purchase, would be unavailable in the event of a system emergency.

Q. If it could, do you believe it would be wise for Idaho Power to rely on the market to meet its peaking needs?

A. Even if Idaho Power could rely on the regional power market as an alternative to building new generation, I believe, as was demonstrated in 2000 and 2001, that relying on the market carries greater risk. Over the long term, the market could arguably be the least cost source for new supply. However, most customers are unable or unwilling to tolerate the price volatility that comes with significant exposure to the market. Moreover, besides its effect on customers, the risk of over-reliance on the market can potentially weaken the financial strength of utilities if extreme price excursions occur.

Conservation

Q. Do you believe that conservation is a viable alternative to adding a new generating resource?

A. Energy conservation should certainly be an ongoing part of all utilities' strategies whenever cost effective. In its 2004 IRP, Idaho Power identified six programs for implementation, all of which were in place and operating by the end of 2005. The two demand response programs, Irrigation Peak Rewards and A/C Cool Credit, resulted in a reduction of summertime peak-hour load of over 43 MW. The other programs, although they will reduce peak load somewhat, are primarily targeted towards achieving energy savings.

Conservation programs of the past, as well as programs underway now, have certainly proven that energy usage can be reduced cost effectively. However, even the most successful conservation programs take time to have an impact and can rarely keep pace with the increasing load growth that must be met. Conservation programs cannot, in my opinion, achieve enough demand reduction, nor can they achieve it quickly or reliably enough, to realistically satisfy the Company's immediate need to meet growing peak loads. Furthermore, traditional conservation is usually spread over all hours and is not necessarily focused on the super peak hours of need identified by Idaho Power.

As a result, I do not believe conservation can be considered a viable stand-alone option to issuance of an RFP for new generation.

Demand Response

Q. Is Idaho Power pursuing demand response programs for the purpose of reducing peak-hourly loads?

A. Yes, the Company has implemented two programs aimed primarily at peak load reduction. I discuss each of them below.

1. A/C Cool Credit

Under this program, Idaho Power manages air conditioning use between 1 p.m. and 9 p.m. for up to 10 days a month from June through August, turning it off no more than 15 minutes at a time. The air conditioner cycling program targets heavy-load hours between June and August. After two summers of a pilot program, the second season of full operation of the program is just now concluding. Idaho Power will continue to ramp up the program by increasing participation levels. The Company expects the program to be fully implemented in 2009. Through the end of July 2006, approximately 3600 customers were participating in the program. Idaho Power reported in its 2005 DSM Annual Report that it expects to achieve a 1.16 kW reduction per participant.

2. Irrigation Peak Rewards

This voluntary program targets irrigation customers with pumps of 100 horsepower or greater with an objective of reducing peak electrical load during summer weekday afternoons by providing control over load demand. The program utilizes electronic time-activated switches to turn off pumps of participating irrigation customers during predetermined intervals. Participants are given a demand credit based on the number of interruptions per week. In 2005, Idaho Power reported that peak energy savings amounted to approximately 40 MW. Results for 2006 have not yet been reported.

Q. Has Idaho Power explored a program to interrupt large commercial, industrial and irrigation loads during peak periods in exchange for credit?

A. During 2001, in response to extremely high market prices and low water conditions, Idaho Power implemented an Energy Exchange program for its largest commercial, industrial and large irrigation customers. Participating customers were required to be able to reduce their electrical load by 1000 kW at each meter point. Under this voluntary load reduction program, Idaho Power offered to credit customers half of the then current market price for each kWh reduced during declared Exchange Events. An Exchange Event was a set of hours during which Idaho Power would ask participants to reduce their

electric load during specific hours on specific days.

The Company reported that of 35 eligible customers, only two customers participated, representing five metering points. These five service points had the combined potential of providing a maximum of 13 MW of load reduction. Most customers, Idaho Power claims, chose not to participate in the program because of their inability to curtail load or because the incentive represents such a small part of the customers' total operating costs. Idaho Power chose to not request an extension of the program.

Alternative Rate Designs

Q. Are there alternative rate designs that can reduce peak hourly loads?

A. Time-of-use (TOU) rates and seasonal rates, particularly for those customer classes whose summertime usage is most responsible for causing the high hourly peaks, are alternative rate designs that can be viable options. In June 2004, Idaho Power implemented seasonal pricing for all residential, commercial and industrial customers and established TOU pricing in addition to seasonal pricing for all industrial customers. The primary objective in implementing these rates was to more closely match prices to the actual cost of power, and to more fairly charge customers based on their pattern of usage. A secondary goal, however, was to encourage

customers to shift usage from on-peak to off-peak hours.

Idaho Power is still exploring time-of-use rates for residential customers. On March 22, 2005, the Commission issued Order No. 29737 approving Schedule 4, the Energy Watch Pilot Program, and Schedule 5, the Time-of-Day Pilot Program. The programs are offered in conjunction with an AMR pilot project involving approximately 23,500 customers in Idaho Power's Emmett and McCall operating areas. On March 3, 2005, the Company requested that the Company be allowed to continue to offer the Time-of-Day and Energy Watch pilot programs until April 1, 2007. So far, the Company has not done an assessment to determine the extent to which peak hour loads have been shifted.

Transmission Upgrades

Q. Idaho Power has contended that the primary reason for needing new generation to be located near its load center is because of transmission constraints on imports from the Northwest. Are transmission upgrades a viable alternative to the Evander Andrews plant?

A. I would characterize transmission upgrades as a necessary component, rather than an alternative, in Idaho Power's plans to meet future peak loads. The Company has been upgrading portions of its transmission system to reduce constraints. The Brownlee to Oxbow project was

completed in late 2003. It increased the Brownlee East capacity by approximately 100 MW. Even with this improvement, however, Idaho Power's transmission system is still constrained at certain times for imports of energy from the Pacific Northwest. Idaho Power is presently upgrading the capacity of the Borah-West path. This will increase the Borah-West transmission capacity by 250 MW and is scheduled for completion in May 2007. The increased transmission capacity will be available to serve Idaho Power's native load requirements with new generating resources located east of the Borah-West constraint (eastern Idaho).

In its 2006 IRP, Idaho Power has expanded its analysis of possible transmission projects, associated costs, and potential risks. Based on its analysis, the preferred portfolio in the draft 2006 IRP incorporates a 285 MW transmission upgrade from McNary (Mid-C) to Boise.

Shoshone Falls

Q. As early as 1993, Idaho Power identified an upgrade to its Shoshone Falls plant as one means of helping to meet future load, but the upgrade has yet to be started. What is the status of the proposed project?

A. It was initially anticipated that capacity expansion of the Shoshone Falls plant would be completed in conjunction with its scheduled FERC relicensing

application to be filed in 1997, and that the expansion would be completed in 2004. However, rather than modifying the re-licensing application, Idaho Power decided to wait until a new license was issued before proceeding with permitting for the Shoshone Falls upgrade. Idaho Power received the new license on August 4, 2004. On August 17, 2006, Idaho Power filed for an amendment to its recently issued license seeking permission to expand the plant to provide an additional 50 MW. During July, when the Company's future peak generation needs are greatest, the upgrade would provide 18 MW under the 90 percent water condition used for capacity planning.

Q. Do you believe that the other resource alternatives that you just discussed can collectively substitute for a new gas fired peaking plant?

A. No, I do not. While I believe each of these other alternatives is important, all of them are either already being pursued and are a part of the Company's plan going forward, or they cannot be counted on with certainty. There may be room for increased efforts, particularly with regard to conservation and demand response, but I believe a new peaking resource is still necessary.

REQUEST FOR PROPOSALS/OVERVIEW OF PROCESS

Q. Please provide a brief overview of the request

for proposals (RFP) issued by Idaho Power.

A. As called for in its 2004 IRP, Idaho Power issued the RFP on March 30, 2005. The RFP sought proposals for a turnkey electric generation resource located within the Company's service territory to meet peak energy demands beginning no later than April 1, 2007. Idaho Power anticipated acquiring 88 MW of delivered capacity, but stated that based on present market conditions of combustion turbines, it was willing to consider acquiring resources from 80 MW to 200 MW. The RFP clearly stated that power purchase agreements where legal title of the generating facilities is not conveyed would not be considered in the RFP. Combustion turbines were identified as the preferred technology. The RFP stated that the primary need for the new resource is to provide electricity during peak energy requirements for the Treasure Valley load center. Idaho Power invited respondents to offer proposals to locate turnkey generating facilities at 1) the Evander Andrews Power Complex site located near Mountain Home, 2) the Bennett Mountain Power Plant site also located near Mountain Home, or 3) at a site of the respondent's choosing.

Bids

Q. Please summarize the response Idaho Power received to its RFP.

A. Idaho Power received 31 proposals from nine companies by the June 2, 2005 RFP deadline. Generating units ranged in size from 71 MW to 171 MW. The proposals included large and small frame combustion turbines, aeroderivative combustion turbines, and reciprocating engines. Projects were proposed at four sites, including the existing Evander Andrews site and the Bennett Mountain site. Both new and secondary market machines were proposed. All of the bids proposed to use natural gas for fuel.

Q. Did Idaho Power prepare a self-build option?

A. No, it did not.

Q. Why not?

A. Idaho Power Company previously issued an RFP for a peaking resource in February 2003. A self-build proposal was prepared during that RFP. However, because the Company does not maintain a significant power plant design and construction workforce, the self-build option represented Idaho Power as a general contractor that subcontracted for materials, design and labor. Idaho Power ultimately determined that not only were bids received in the 2003 RFP process competitive, but also that the selected Mountain View Power bid for the Bennett Mountain project was superior to the self-build option. With the 2005 RFP, the Company was convinced that based

upon recent experience with the 2003 RFP process, it would receive sufficient competitive bids, the Company had reasonable benchmarks for peaking unit prices, and that expenses associated with self-build bid preparation could be avoided.

Q. Do you agree with the Company's decision not to include a self-build option?

A. Yes, I do. If Idaho Power had prepared a proposal in which it acted as a general contractor and subcontracted for engineering, materials and construction, I have no reason to believe it could build the project less expensively than a contractor who specializes in building power plants.

Q. Do you believe that the number and variety of proposals received was sufficient to give reasonable assurance that all realistic options could be considered and that a competitive price could be obtained?

A. Yes, I do. Each of the nine companies submitting bids had previous experience developing similar projects. Moreover, the 31 bids included several types and sizes of equipment. Approximately one-third of the bids were for aeroderivative units close to the 88 MW capacity sought in the IRP, approximately one-fourth were for small frame units in the 70-100 MW size range, and the remainder were large frame units in the 150-170 MW range.

In addition, there was one bid for reciprocating engines. There were considerably more bids received in this RFP than in previous RFPs for the Bennett Mountain and Danskin projects.

Evaluation of Bids

Q. Please briefly describe the bid evaluation process used by Idaho Power.

A. To review and score proposals, Idaho Power assembled an evaluation team consisting of six employees - three from the Power Production business unit, one from Power Supply Reporting, one from Load Research, and one from the Pricing and Regulatory Services business unit of the Company. In addition, two advisors – one from the Company's Legal Department and one from Power Engineers, a third party consultant – provided guidance to the evaluation team.

The evaluation team ranked the proposals using the procedures and criteria outlined in an Evaluation Manual prepared prior to the receipt of bids. Idaho Power prepared the Evaluation Manual with the assistance of Power Engineers, its consultant. The Evaluation Manual identified the criteria upon which the proposals would be scored, assigned a maximum number of points to each criterion, and provided a scoring guide to be used in determining how points would be awarded for each

criterion.

This section (Pages 29 to 30) of Staff's direct testimony contains confidential information subject to protective agreement. This section is attached as Confidential Exhibit No. 115.

Q. How were non-price scores determined?

A. To evaluate the bids based on non-price criteria, Idaho Power's evaluation team reviewed the proposals and collectively awarded a single set of points to each proposal in each category. Scores for all factors

were then totaled for each bid.

Q. Do you believe that the non-price criteria used in the evaluation were reasonable?

A. I believe the evaluation criteria were reasonable and not intended to favor one proposal over another. The criteria were established prior to the receipt of bids with the guidance and assistance of a third-party consultant. However, many of the non-price criteria required subjective judgment in point factoring, which made them prone to bias.

Q. Were all of the exact evaluation criteria and the points associated with each made known to bidders in advance?

A. No, all of the price and non-price scoring criteria, including the methods by which scores would be awarded, were kept confidential, both before bids were submitted and after the evaluation process was complete. Although details of the price evaluation methodology were not disclosed, bidders should have obviously known that price would be a major factor in the scoring. The non-price evaluation criteria were not nearly as well known by bidders, although the RFP did give some indication of what criteria might be used. For example, the RFP stated "Projects that provide advantageous siting, demonstrated community acceptance, completed environmental analysis,

completed archaeological analysis, and completed permitting may be viewed favorably in the selection process." Reference RFP page 14.

The RFP also included the following in its list of non-price attributes to be considered in the evaluation of proposals:

- Provide an advantageous project location considering: grid location, zoning, community acceptance, use of existing IPC operation and maintenance personnel, local water supply and other environmental impacts; and
- Demonstrate enhancement of IPC system reliability, integrity, and utilization through application of mature technologies. Reference RFP page 22.

Q. Do you believe that all evaluation criteria and methods should be kept confidential in the future?

A. No, I do not. Obviously, I believe that bids should be kept confidential and that price information should not be publicly divulged at any time in the evaluation process. However, I see no compelling reason for the exact price and non-price evaluation methodologies and criteria to be kept confidential. If all bidders know in advance what criteria and methods will be used to evaluate their proposals, I believe they are more likely

to make proposals that more closely match the utility's needs and preferences. By keeping evaluation criteria confidential, competition between bidders is stifled. I recommend that all evaluation criteria and methods be divulged in future RFPs.

Q. Were transmission costs considered in evaluating bids?

A. Yes, transmission costs were considered when evaluating all bids. The transmission cost estimates were based on studies performed by Idaho Power's Transmission business unit ("Delivery"). Studies were developed for each of the four different sites included in the bids and for various proposed equipment sizes. Projects of similar size at the same proposed locations were consistently assigned the same transmission costs. Although considered in the bid analysis, transmission costs have not been included in the Company's Commitment Estimate.

Q. Did the RFP inform bidders of the likely transmission cost differences based on where projects might be located?

A. Respondents were advised in the RFP that proposals for projects to be located at sites other than Evander Andrews or Bennett Mountain that depend on transfer of energy across the transmission constraints for delivery to the Boise area will have an extremely heavy

burden to demonstrate to Idaho Power's satisfaction that sufficient transmission capacity can be made available in time to meet the April 1, 2007 provisional acceptance deadline. The RFP included approximate transmission pricing information based on proximity to the Boise area. Four cost zones were identified. Costs of $3 to $10 million were estimated for the zone encompassing the Boise-Caldwell area. An estimated cost of $15 to $25 million was given for the zone reaching from the greater Boise area to Ontario. Costs of $20 to $40 million were estimated for the zone between Boise and Midpoint (including the Mountain Home area). Finally, costs of $30 to $60 million were estimated for sites east of Midpoint.

Q. Do you believe bidders took this information into account when preparing their bids?

A. Absolutely. There were only four locations at which projects were proposed to be built — the Evander Andrews and the Bennett Mountain sites near Mountain Home that were identified in the RFP, and two other sites. Both of the other sites were within the zone encompassing the Boise load center in which transmission costs were expected to be lowest. Some bidders apparently recognized that their proposals could win an immediate price advantage of from $17 to $30 million over the Evander Andrews and Bennett Mountain sites if they found sites

close to Boise.

Q. What natural gas price was used in performing the price analysis?

A. Gas prices were assumed to be $4.61 per MMBtu in 2007 and were escalated throughout the life of the project. These were the same gas prices assumed by Idaho Power in its 2004 IRP.

Q. Were the gas prices assumed in the cost analysis critical to the results?

A. Because the same gas price was utilized for all project proposals, projects with lower guaranteed heat rates had lower fuel costs on a cost per MWh basis. However, because variable costs were only used to determine relative variable cost scores, the exact gas price used was not critical as long as it was the same for all proposals.

Short List Analysis

Q. Please describe how Idaho Power developed a short list of projects and completed further analysis of the short list proposals.

A. After the stage 2 screening was completed, the top fifteen proposals (from four different bidders) were short-listed and meetings with representatives of the short-listed entities were held in October 2005. The Company sent a document to each of the short-listed

bidders detailing the Company's understanding of each respective bid. The review of those documents and the meetings with bidder's enabled Idaho Power to clarify bids, such as definitively determining what things were or were not included in the bid, so that a revised second-round analysis could be completed. A copy of Idaho Power's summary of the fifteen short-listed proposals, along with a summary of the price and non-price factor scores is attached in confidential Exhibit No. 108.

Following the meetings with the short-listed bidders and based on the results of the second-round evaluations, the Company pursued final negotiations with two bidders who had each submitted three different proposals.

Analysis of Final Candidate Proposals

Q. Were the final candidate proposals modified before Idaho Power made its final analysis of the proposals?

A. During the final stage of the analysis, Idaho Power decided to delay the proposed on-line date of the project from June 2007 until April 2008. As a result, the two finalist bidders were requested to modify their bids to reflect the revised on-line date. The six modified bids were then compared in the final analysis. A summary of the six finalist bids is attached as confidential

Exhibit No. 109. Based on the final analysis, the RFP evaluation team made its recommendation to the Company's management, who in turn recommended to the IdaCorp Board of Directors that the Siemens Power Generation, Inc. Evander Andrews bid be selected.

This section (Pages 37 to 52) of Staff's direct testimony contains confidential information subject to protective agreement. This section is attached as Confidenital Exhibit No. 116.

PROJECT DESCRIPTION

Q. Please describe the proposed Evander Andrews plant.

A. The proposed Evander Andrews plant will be a nominal 170 MW natural gas fired, simple cycle power plant to be located at the existing approximately 40-acre Evander Andrews Power Complex located north of I-84 approximately two miles northwest of the City of Mountain Home. In 2001, Idaho Power built two 45-MW simple cycle combustion turbines at the site, which were formerly sometimes referred to as the "Danskin Plant." The proposed project's combustion turbine is a single Siemens Westinghouse model 501F (also known as SGT6-5000F).

Operation

Q. Please describe the expected operation of the proposed Evander Andrews plant.

A. If approved, the Evander Andrews plant will be

operated to meet peak-hour loads primarily in the summer and winter. The plant is currently scheduled to be available to meet peak loads in April of 2008. While there may be occasional opportunities to market the output of the Evander Andrews plant when it is not needed to meet the Company's own load, Idaho Power does not anticipate marketing a significant amount of the plant's output. The opportunity for sales of surplus energy will depend on the difference between the market price of power and the Evander Andrews plant's cost of production. Because Evander Andrews is a simple cycle plant, its dispatch cost is higher than combined cycle plants in the region; consequently, it may not often be cost effective to operate the plant to make off-system sales.

Fuel Supply and Transportation

Q. As a part of this Application, Idaho Power is requesting that it be allowed to include the project's cost of fuel, fuel storage and fuel transportation for recovery through the existing Power Cost Adjustment (PCA) mechanism. Do you agree that this is appropriate?

A. A major component of the operating costs of a combustion turbine generating plant is the cost of natural gas fuel. Staff agrees that reasonable fuel expenses should be approved for PCA recovery prior to full review of normal operational costs in a general revenue

requirement case. Operation of the plant will displace other more costly power supplies to the benefit of Idaho Power customers; therefore, costs should be included in the PCA. This is consistent with the manner in which fuel costs are handled for the Bennett Mountain and Danskin plants.

Q. How will natural gas be delivered to the plant?

A. A natural gas fuel supply will be delivered from the Williams Northwest Pipeline via an existing pipeline to the Evander Andrews site. Idaho Power has not yet negotiated or entered into any agreements for the purchase of natural gas fuel supplies for the proposed Evander Andrews plant.

Q. How does Idaho Power manage the risk associated with purchasing natural gas for fuel?

A. Idaho Power has an Energy Risk Management Policy and natural gas is listed as a permitted commodity; however, the policy does not specifically address acquisition of natural gas. An internal Risk Management Committee regularly quantifies, assesses, and manages the Company's risk in accordance with the Risk Management Policy.

Idaho Power also has gas hedging guidelines for the existing Evander Andrews/Danskin Power plant. If the new Evander Andrews plant is approved, I would expect the

Company to develop its fuel procurement strategy for both natural gas and transportation capacity as well as expanded hedging guidelines and risk management strategies for all of the Evander Andrews plants and the Bennett Mountain plant.

Q. Does Idaho Power have adequate fuel transportation rights on the Williams Pipeline to accommodate the proposed plant?

A. Idaho Power already possesses firm fuel transportation rights that can be used for both the existing and new Evander Andrews plant and the Bennett Mountain plant. Sufficient transportation rights to serve the Evander Andrews plant are available without a pipeline expansion.

Water Supply and Wastewater Treatment

Q. What is Idaho Power's plan for water supply and wastewater treatment?

A. Water would be used by the plant primarily for evaporative cooling, which is normally only required in the summer months. Water can be supplied by an existing well at the Evander Andrews site. Wastewater from the plant will be retained in an existing retention pond and then pumped out for irrigating landscaping.

Electrical Interconnection

Q. What transmission work would have to be done in

order to interconnect the proposed plant?

A. In order to interconnect the proposed plant, a de-energized 132 kV transmission line between the Bennett Mountain plant and the Mora substation near Boise would have to be rebuilt to 230 kV. The route of this line passes in the vicinity of the Evander Andrews site. An additional transmission improvement would be needed between the Evander Andrews plant and the existing Bennett Mountain plant. The estimated total cost for the transmission work is estimated at $26 million, with approximately $22 million allocated to the Evander Andrews Project for the generator interconnection and the remaining $4 million allocated to Idaho Power Delivery to correct existing operational concerns. At this point, costs are based on a feasibility study and are only rough estimates. Detailed costs would be developed in a Design Study. The $22.8 million amount for transmission discussed in the Company's application is simply the initial $22 million amount escalated by the one year the project was delayed. The cost of this transmission upgrade is <u>not</u> included in the project commitment estimate and could be higher or lower.

Project Permits

Q. Please discuss the air quality permit that will be required for the proposed plant.

A. Certainly one of the most critical permits needed by the project is an air quality permit (Permit to Construct) issued by the Idaho Department of Environmental Quality (DEQ). Idaho Power has not yet made an application for such a permit; however, the Company's environmental consultant has completed the necessary studies to prepare an application for a permit. The studies indicate that the expected emission from the proposed plant will be less than half the emissions from the recently completed Bennett Mountain plant. I have discussed the permit with DEQ staff and they do not expect Idaho Power to have any difficulty in obtaining a permit. The time needed to obtain a permit was estimated by DEQ to be approximately 160 days.

Q. Will the project require a Conditional Use Permit?

A. A gas-fired combustion turbine is a permitted use within the existing zoning designation where the Evander Andrews project is located. Consequently, Elmore County will not require a Conditional Use Permit.

Q. Will other permits be required?

A. Yes, but because two smaller gas-fired turbines are already operating at the Evander Andrews site, additional required permits will be minor. Permits will be necessary for such things as transporting materials and

equipment on public highways; disposing of excavated materials; insuring compliance with construction noise and building permits.

Environmental Impacts

Q. What will be the most significant environmental impact of the proposed project?

A. The most significant environmental impact of the Evander Andrews project will be air emissions. The primary pollutants from gas-fired plants are NOx and carbon dioxide. The DEQ Permit to Construct will specify emission limits for the project.

Project Risks

Q. What are some of the risks associated with the Evander Andrews project?

A. There will be some risk associated with the Evander Andrews project simply because it uses natural gas for fuel. As evidenced by the past several years, gas prices can be quite volatile. The project would increase the amount of gas-fired generation in Idaho Power's fleet to 422 MW. Owning gas-fired generation could perhaps ultimately lead to slightly greater rate stability than if the same output were purchased from the market, but Idaho Power cannot escape gas price risk.

Project Benefits

Q. What would be some of the benefits of the

Evander Andrews project?

A. There are several notable benefits to the proposed Evander Andrews project. First, the cost of the project, although slightly higher than the recently completed Bennett Mountain project, is still quite attractive, primarily due to the availability of combustion turbines at bargain prices. Turbine prices are currently very low because equipment destined for new plants now has nowhere to go due to numerous plant cancellations, the financial difficulties of many developers, and the demise of others.

Second, the Evander Andrews project appears to have strong local acceptance. This would be the third gas-fired combustion turbine project in the Mountain Home area. I am not aware of any local opposition.

Third, the new proposed Evander Andrews plant would be located at the site of an existing plant (Danskin), and is only a few miles from the Bennett Mountain plant, enabling sharing of operational staff and equipment.

Finally, the Evander Andrews plant will be fully dispatchable and available for use by Idaho Power at any time. If another entity owned the plant and Idaho Power purchased output under a power purchase agreement, this would not be possible.

FUTURE NEEDS

Q. The proposed Evander Andrews project would add 170 MW of peaking capacity to Idaho Power's portfolio, yet the 2004 IRP upon which the RFP was based indicated a need for only 88 MW of peaking capacity. Will this extra peaking capacity be needed in the future?

A. Idaho Power's peak load is growing at a rate of about 80 MW per year. The Company's average load is growing at about half that rate. Idaho Power is currently in the process of finalizing the 2006 IRP, which more closely examines both the magnitude and timing of the Company's future resource needs. The 2006 IRP does not call for any near-term additions of peaking generation resources, although it does call for expansion of some demand reduction programs. In addition, it calls for completion of the 100 MW RFP for wind, completion of the 100 MW RFP for geothermal, possibly the issuance of an RFP for 50 MW of CHP, a 225 MW upgrade to the McNary-Boise transmission line, and continued investigation into the possibility of jointly developing a coal project. The additional peaking capacity provided by the proposed Evander Andrews plant will help to satisfy peak load requirements in the future and enable the Company to add mostly base-load generation that will be used to meet both peak and average load growth.

CAPITAL COST COMMITMENT ESTIMATE

Q. Please discuss Idaho Power's capital cost "Commitment Estimate."

A. Idaho Power has negotiated a contract with Siemens Power Generation Inc. containing a firm price for the completed project in the amount of $49,999,000. Based on this contract, Idaho Power states that it is able to make a reliable estimate of the total capital cost of the project. This estimate, which Idaho Power has termed a "Commitment Estimate" is a good faith estimate of the project's total capital cost based on the contract with Siemens plus certain additional costs the Company knows it will incur but cannot quantify with precision at this time. These additional costs include (but are not limited to) sales taxes, AFUDC, the cost of Idaho Power oversight of the project and the cost of capitalized start-up fuel. These additional costs would be approximately the same regardless of which proposal Idaho Power had selected. The Commitment Estimate also covers contingencies such as change orders and other unforeseen events. Idaho Power's Commitment Estimate for the project is $60 million, or about $10 million more than Siemens contract amount.

Idaho Power states that it will commit to procure and install the Evander Andrews project for the Commitment Estimate. The Commitment Estimate would also

be subject to adjustment to account for documented legally required equipment changes, such as to comply with new air quality laws for example, and for extreme changes in inflation and prices. If the final capital cost of the project exceeds the Commitment Estimate, Idaho Power states that it will absorb the extra cost. The Company will include in its Idaho rate base only the amount actually incurred up to the Commitment Estimate.

If the project is approved for rate base treatment, Idaho Power has pledged to provide the Commission with periodic percentage of completion and cost expenditure reports during the construction phase. The final report on the project will compare the actual completed cost to the Commitment Estimate.

Q. What is not included in Idaho Power's Commitment Estimate?

A. The Commitment Estimate does not include the cost of constructing or upgrading transmission facilities to interconnect the project with the Company's existing transmission system. The studies needed to fully define interconnection and transmission upgrade costs have not been completed. However, Idaho Power's Transmission Business Unit (Delivery) has provided a preliminary upper limit estimate of $22.8 million to interconnect the project.

Q. Do you believe that the Commitment Estimate of $60 million is reasonable?

A. Yes, I believe that the Commitment Estimate for the project is reasonable. The Commitment Estimate for the Bennett Mountain plant, which was a nearly identical plant completed in 2005, was $54.0 million, excluding transmission. The Bennett Mountain plant produces about 8 less megawatts than the proposed Evander Andrews plant, but emits nearly twice as much NOx. I think both projects, due to an ongoing abundance of turbines available in the market, reflect excellent prices by standards of the past several years. Siemens is able to construct the project at significantly lower costs than similar projects constructed just a short time ago. The commitment cost of $60 million for the 170 MW Evander Andrews project is just $11 million more than the $49 million cost of the 90 MW Danskin project completed in September 2001.

Q. Are you willing to accept costs up to the Commitment Estimate for future inclusion in rate base?

A. No, I am not. The Idaho Power-Siemens contract amount of $49,999,000 is a known amount that, except for possible change orders, will not change once Idaho Power takes ownership of the plant. Moreover, the amount was established through a competitive bidding process that the

Staff finds acceptable. Consequently, I am willing to accept cost up to this amount in rate base. However, those costs above the $49,999,000 contract amount, up to the Commitment Estimate of $60 million, cannot be quantified with precision at this time according to Idaho Power. Furthermore, those expected costs might not be subject to a competitive bidding process, or to the advance scrutiny of the Commission or its Staff. Consequently, I recommend that these expected costs (up to a maximum $ 10,001,000) be subject to audit by the Commission Staff, and that the Commission withhold rate base consideration of these costs until after the project is constructed and the audit is completed.

Q. Idaho Power has provided a Commitment Estimate of $60 million for construction of the proposed Evander Andrews project and has estimated that transmission costs to interconnect and integrate the plant into its system will be an additional $22.8 million. The $22.8 million is not included in the $60 million Commitment Estimate, however. Why did Idaho Power not provide a similar commitment estimate for transmission costs, like it did for plant construction?

A. As explained by Company witness Said in his direct testimony, a Certificate of Convenience and Necessity is only required for construction of new

generation facilities. Such a certificate is not required for construction of transmission facilities in a territory already served by the utility.

Q. Do you agree?

A. Yes, *Idaho Code* §61-526 requires certificates of public convenience and necessity for generation projects but not for extension of existing transmission systems. Thus, once the new transmission line has been built and is used to provide power to customers, Idaho Power will presumably seek to include these transmission costs in rate base. At that time, a judgment of whether transmission costs have been prudently incurred would be made.

However, whether a certificate is required or not, I see little difference in the reason for requiring a commitment estimate for new generation plant or for a new major transmission addition needed to deliver that generation. I believe it is necessary and prudent to obtain a commitment estimate for transmission as well, for two reasons. First, with a transmission cost estimate of $22.8 million, transmission costs represent about 27.5 percent of the entire project cost. Second, the plant is inextricably linked to the transmission. In other words, the plant is not useful without the upgraded transmission that Idaho Power says is necessary to bring generation to

the Treasure Valley load center.

Q. Would you be willing to accept the Company's estimate of $22.8 million for transmission costs as a commitment estimate?

A. No, the $22.8 million estimate for transmission is only a preliminary cost estimate based on the initial feasibility study; therefore, the estimate is not precise. A more detailed analysis would be required in order to establish a commitment estimate. In fact, based on its response to Staff production request No. 94, even Idaho Power itself is not willing to provide a commitment estimate for transmission at this time. As stated by the Company, "Idaho Power Company is unable to provide a commitment estimate for transmission costs that would be incurred to integrate the proposed new Evander Andrews generating plant, similar to the Commitment Estimate offered for the plant construction. … At the present time, only feasibility and technical studies have been completed for the transmission improvements required to integrate the new facility into the Company's transmission system."

Furthermore, even if transmission costs are more accurately determined and a commitment estimate provided in the future, I would still recommend that the Company not be allowed to recover costs in excess of the lower cost proposal. Because the excess costs are due primarily

to transmission, I would expect this amount to be deducted from the transmission cost commitment estimate.

Q. Are there other ways to help insure that transmission costs will be reasonable?

A. Yes, it is likely that Idaho Power would solicit bids for the majority of the required transmission work rather than complete the work using its own staff. As long as the job, including materials, is competitively bid, it is reasonable to expect that a competitive price would be obtained. While this doesn't guard against the possibility of transmission costs greatly exceeding the estimate, it at least offers some protection that transmission costs will be reasonable. Nevertheless, I still believe that Idaho Power should develop and be bound by a commitment estimate for transmission.

TOTAL EXPECTED POWER COST

Q. What is the total expected power cost for the proposed Evander Andrews plant?

A. Based on Idaho Power's economic analysis of the proposal, including the estimate of $22.8 million for the cost of transmission and the Siemens contract amount of $49.999 million, the 30-year fixed levelized cost of energy from Evander Andrews will be $4.23 per kW-month. The 30-year levelized dispatch cost would be $61.09 per MWh using the Company's assumed gas prices. The total

cost of power is the sum of these two components.

Q. Why didn't Idaho Power compute a total power cost in dollars per MWh rather than computing two separate cost components?

A. In order to compute the total power cost as a single dollars per MWh figure, an assumption must be made about the plant capacity factor i.e., the percentage of time the plant is expected to operate. While it is easy to assume a capacity factor, the assumption is invariably going to be wrong because plants such as Evander Andrews are usually operated in response to deviations from normal water, load, or market conditions. For peaking plants that are expected to operate relatively few hours per year, this approach produces a total power cost that seems very high because fixed costs get spread over very few hours in the year. Moreover, this high cost per MWh is frequently misused when it is compared to the cost of other resources or alternatives with much higher capacity factors.

It is also extremely important to recognize that the price of energy computed for analysis purposes is highly dependent on the cost of gas that is assumed in the analysis. Idaho Power's analysis assumed a starting gas price of $4.61 per MMBtu, with prices in future years based on various forecasts available to the Company.

These estimates may be reasonable based on today's gas prices and forecasts, but prices could turn out to be much different than assumed in the analysis. Because each of the proposals considered by Idaho Power in the final analysis proposed to use gas as fuel, the effect of different gas prices was similar on each proposal's cost, except to the extent some projects may have been more efficient than others.

Q. Can you compare the total cost of power from the project to other market alternatives?

A. It is difficult to make a comparison to other market alternatives because it could be argued that the market is not really an alternative to the Evander Andrews plant due to transmission constraints. However, just for the sake of comparison, I asked Idaho Power to make estimates of the monthly heavy load hour prices for the next five and ten-year periods. The Company's estimated average 5-year heavy load hour price is $68.44 per MWh, and the average 10-year price is $70.24 per MWh. These prices are almost certainly lower than the total costs of the Evander Andrews plant because its estimated dispatch cost alone is $61 per MWh. The addition of fixed costs would increase that total substantially.

Q. Are avoided cost rates for PURPA contracts a fair comparison to expected costs of the Evander Andrews

plant?

A. I do not believe avoided cost rates used for PURPA QF contracts is a fair comparison to the cost Idaho Power will pay for power from the Evander Andrews plant. Avoided cost rates are computed using a combined cycle combustion turbine rather than a simple cycle turbine like Evander Andrews. Avoided cost rates are not really comparable to the Evander Andrews power costs because they represent the price of two very different products. Avoided cost rate computations assume that the plant is operated nearly all of the time, not just during a limited number of peak hours in the summer and winter. Avoided cost rates are reflective of the cost of base load generation, while Evander Andrews is dedicated to providing peaking capacity.

SUMMARY AND RECOMMENDATIONS

Q. Are you convinced that Idaho Power has demonstrated a genuine need for the Evander Andrews plant?

A. Yes, I am convinced that peaking power is needed by Idaho Power beginning in the summer of 2008, and that construction of a peaking plant is the Company's best alternative. Under the right set of circumstances, I believe it might be possible for Idaho Power to find enough alternatives that collectively could eliminate, or at least defer, the need for the Evander Andrews plant.

However, some of the possible alternatives - such as new industrial cogeneration, increased PURPA development, or significantly increased participation in DSM and demand response programs - are mostly outside of the control of the Company. Relying on them would be very risky.

Q. Do you believe that the request for proposals, the criteria used by Idaho Power to evaluate bids, and analysis of the bids was fair to all proposals?

A. I believe that the RFP was fair and that the evaluation criteria were reasonable. However, because some of the non-price evaluation criteria were subjective and because some of the scores would likely be different based on what is known today, I do not believe that the process produced a fair outcome. In addition, I recommend that in future RFPs Idaho Power be required to divulge all criteria and methods that will be used to evaluate proposals so that bidders can more effectively compete.

Q. Do you recommend that the Commission issue to Idaho Power a Certificate of Public Convenience and Necessity to construct the new Evander Andrews plant?

A. Yes, with reservations. I believe that in the ordinary course of events the Commission may authorize the rate basing of the amount of the Siemens Evander Andrews Agreement amount of $49,999,000. I recommend that the actual amount of capital costs to be rate based above the

bid price of $49,999,000 up to the Commitment Estimate of $60 million be subject to review in a subsequent case. In addition, I recommend that Idaho Power be ordered to develop a commitment estimate for the cost of constructing the transmission and substation facilities necessary for the Evander Andrews plant. **This section of Staff's direct testimony contains confidential information subject to protective agreement. This section is attached as Confidenital Exhibit No. 117.**

If the Commission approves a Certificate of Convenience and Necessity for the project and rate base treatment in the normal course of events, I recommend that Idaho Power be ordered to provide the Commission with periodic percentage of completion and cost expenditure reports during the construction phase.

Q. What is your recommendation with regard to fuel for the Evander Andrews plant?

A. I recommend that Idaho Power be allowed to include the project's cost of fuel, fuel storage and fuel transportation for recovery through the existing Power Cost Adjustment (PCA) mechanism.

Q. Do you have any other recommendations?

A. I also recommend that the Company be strongly encouraged to diligently continue to investigate and, where warranted, begin implementing conservation, demand

response and pricing options that could potentially displace or defer the need for additional future peaking generation.

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

A. Yes, it does.

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

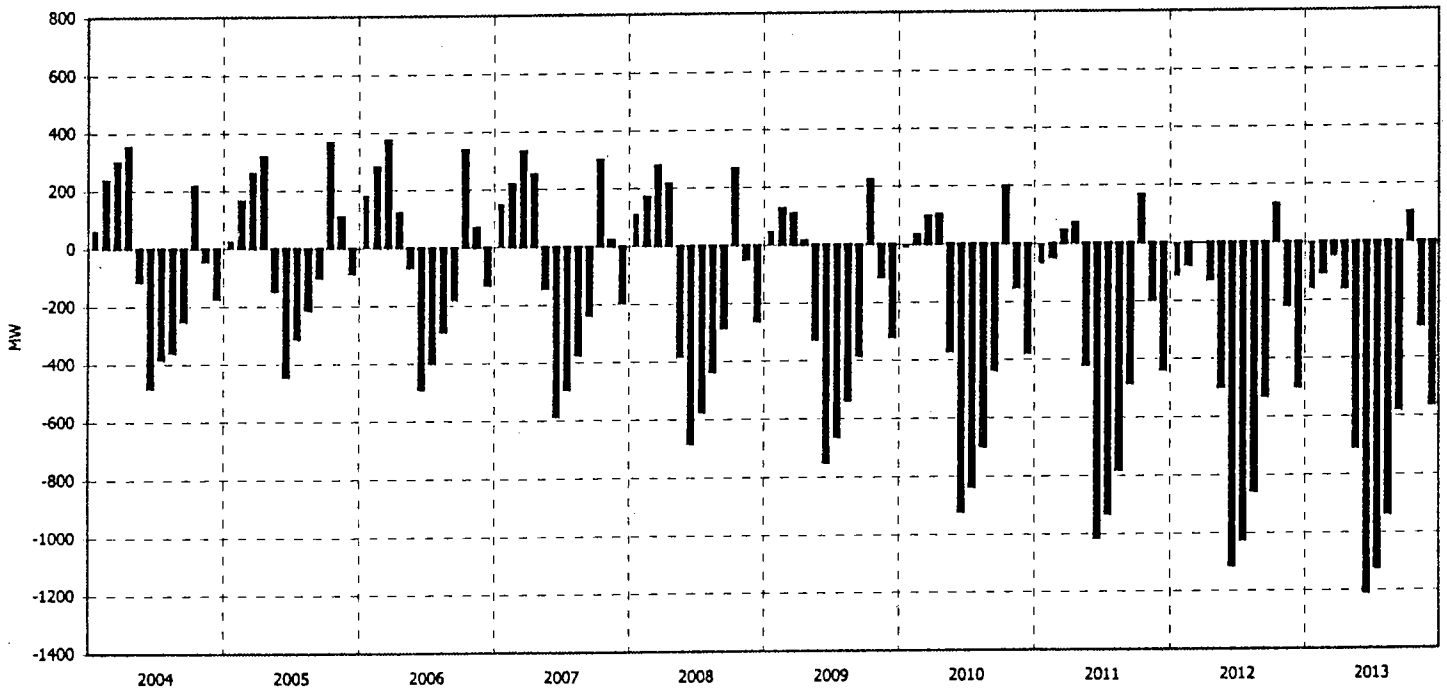

Exhibit No. 101
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R. Sterling, Staff
10/10/06

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

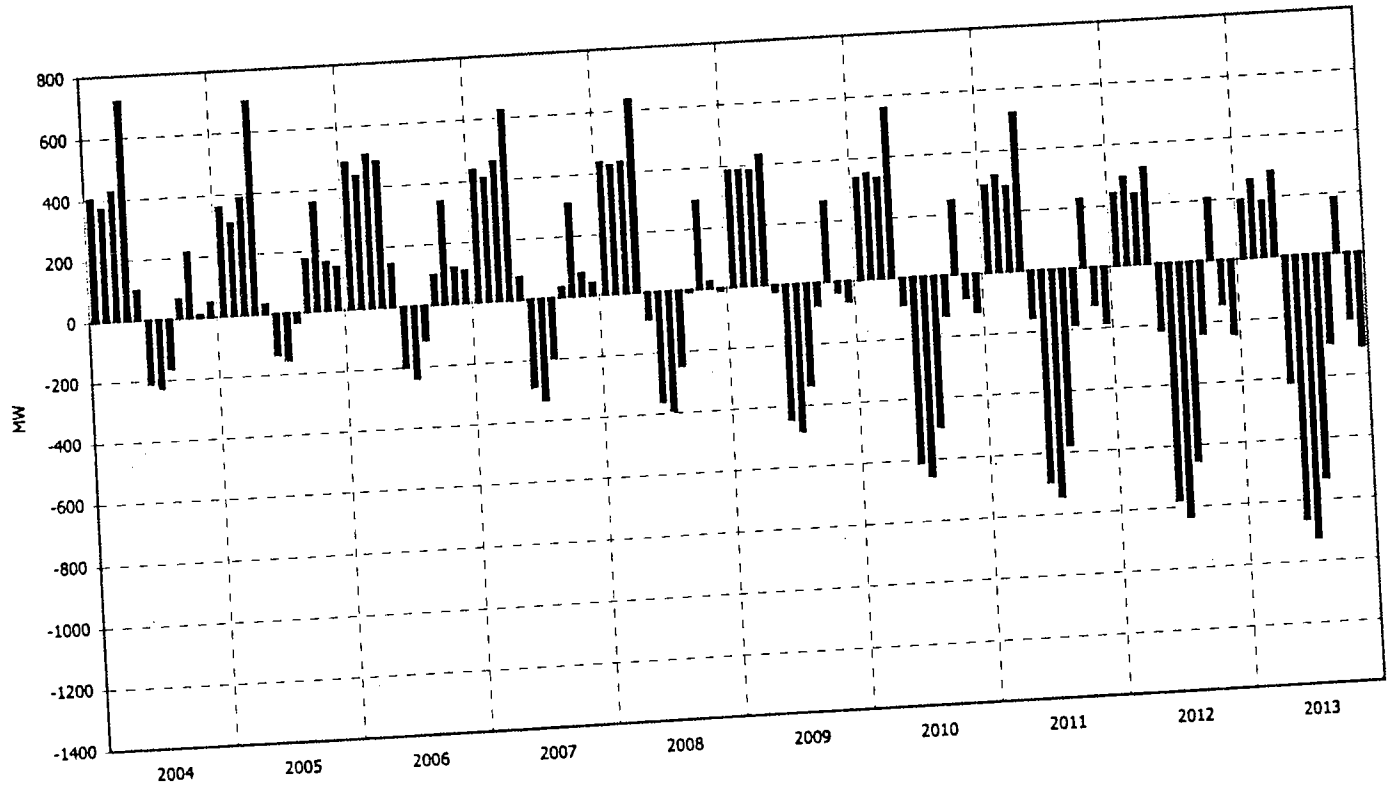
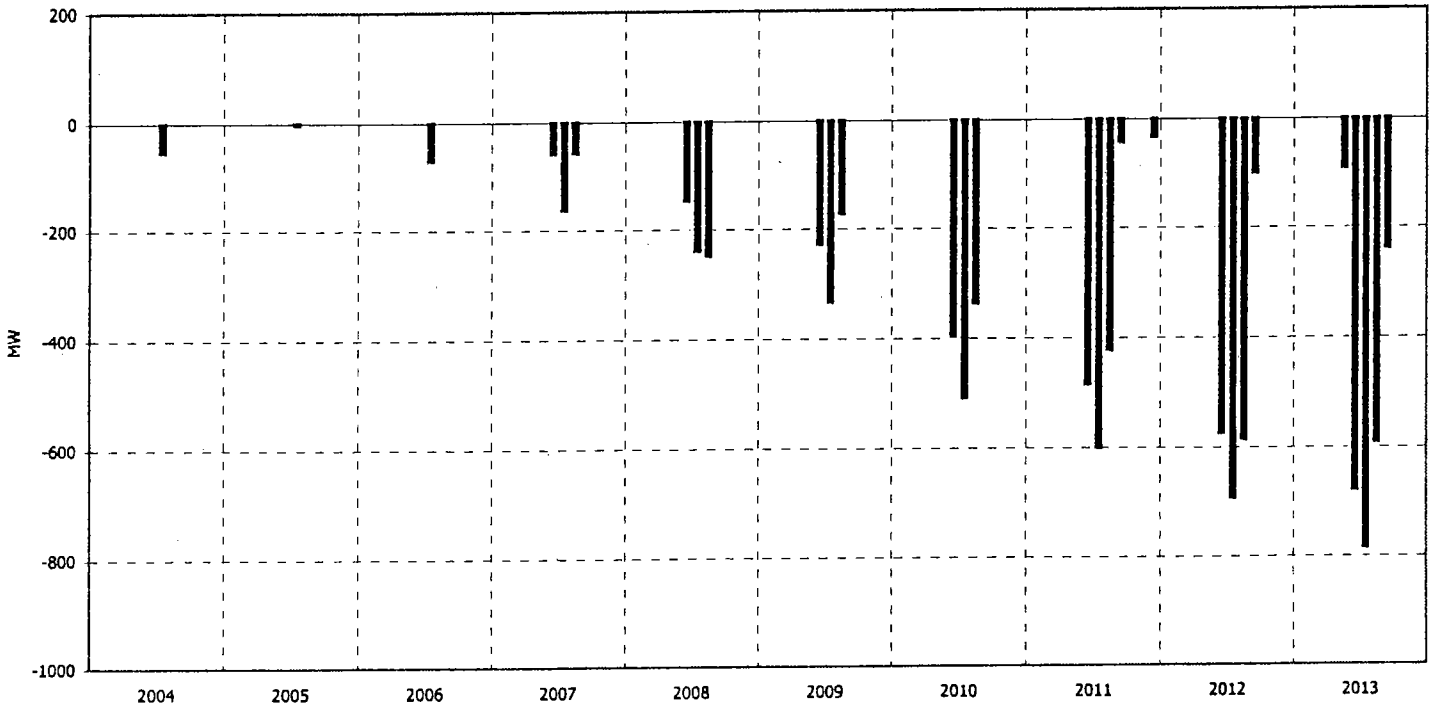


Exhibit No. 102
Case No. IPC-E-06-9
R. Sterling, Staff
10/10/06

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



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R. Sterling, Staff
10/10/06

Figure 4-2. Monthly Peak-Hour Surplus/Deficiency 90th Percentile Water, 95th Percentile Peak Load (Existing and Committed Resources)

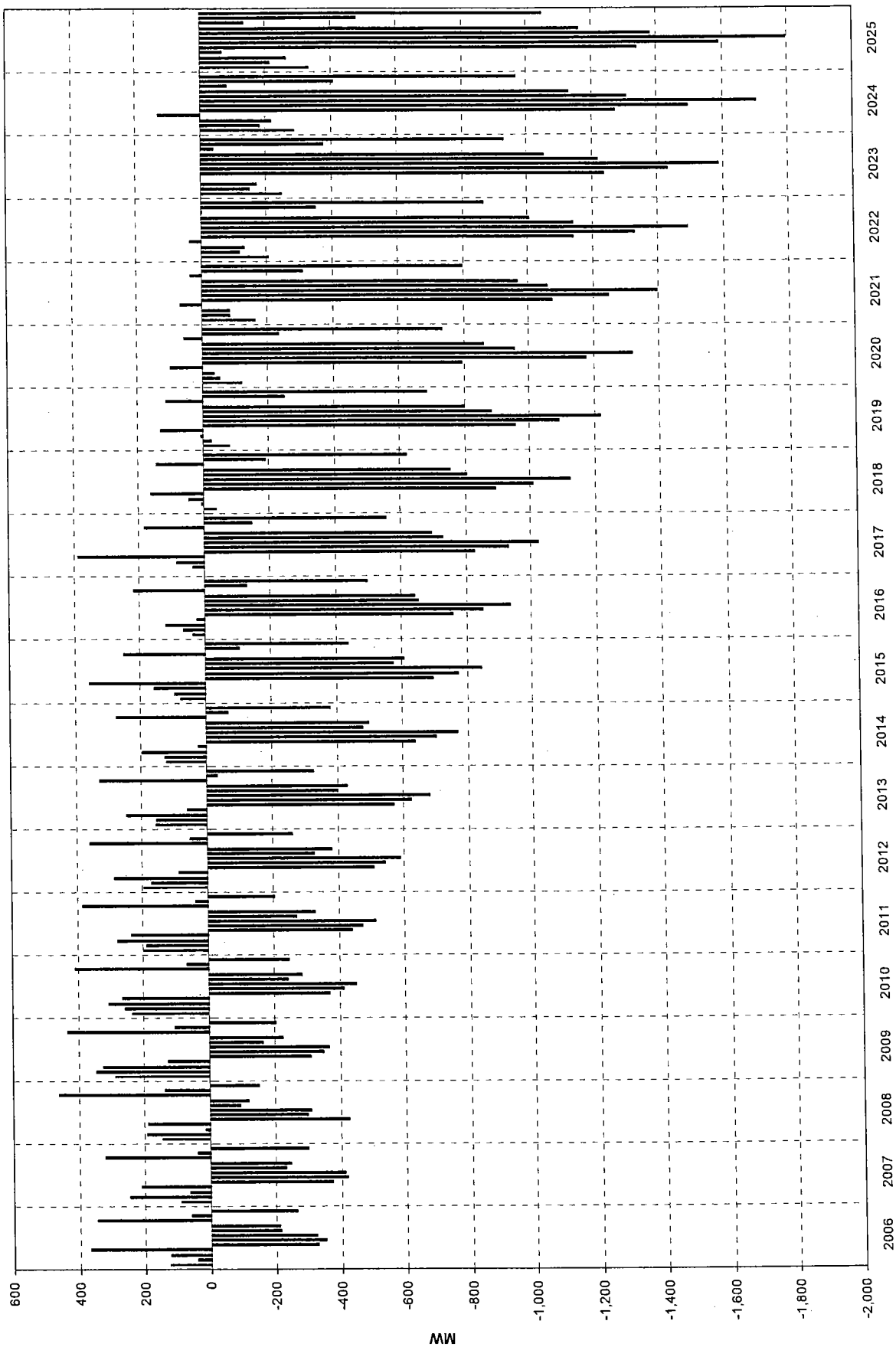

Exhibit No. 104
Case No. IPC-E-06-9
R. Sterling, Staff
10/10/06

Table 1-1. 2006 Preferred Portfolio Summary and Timeline

Summary

Resource	MW
Wind	250
Geothermal (Binary)	150
CHP	150
Transmission	285
Coal	250
Regional IGCC Coal	250
Nuclear	250
Total Nameplate	**1,585**
DSM	187
Energy	1,091
Transmission	285
Peak	1,250

Timeline

Year	Resource	MW
2008	Wind (2005 RFP)	100
2009	Geothermal (2006 RFP)	50
2010	CHP	50
2012	Wind	150
2012	Transmission McNary–Boise	225
2013	Wyoming Pulverized Coal	250
2017	Regional IGCC Coal	250
2019	Transmission Lolo–IPC	60
2020	CHP	100
2021	Geothermal	50
2022	Geothermal	50
2023	INL Nuclear	250
	Total Nameplate	**1,585**

Exhibit No. 105
Case No. IPC-E-06-9
R. Sterling, Staff
10/10/06

Figure 4-3. Monthly Peak-Hour Northwest Transmission Deficit 90th Percentile Water, 95th Percentile Peak Load (Existing and Committed Resources)

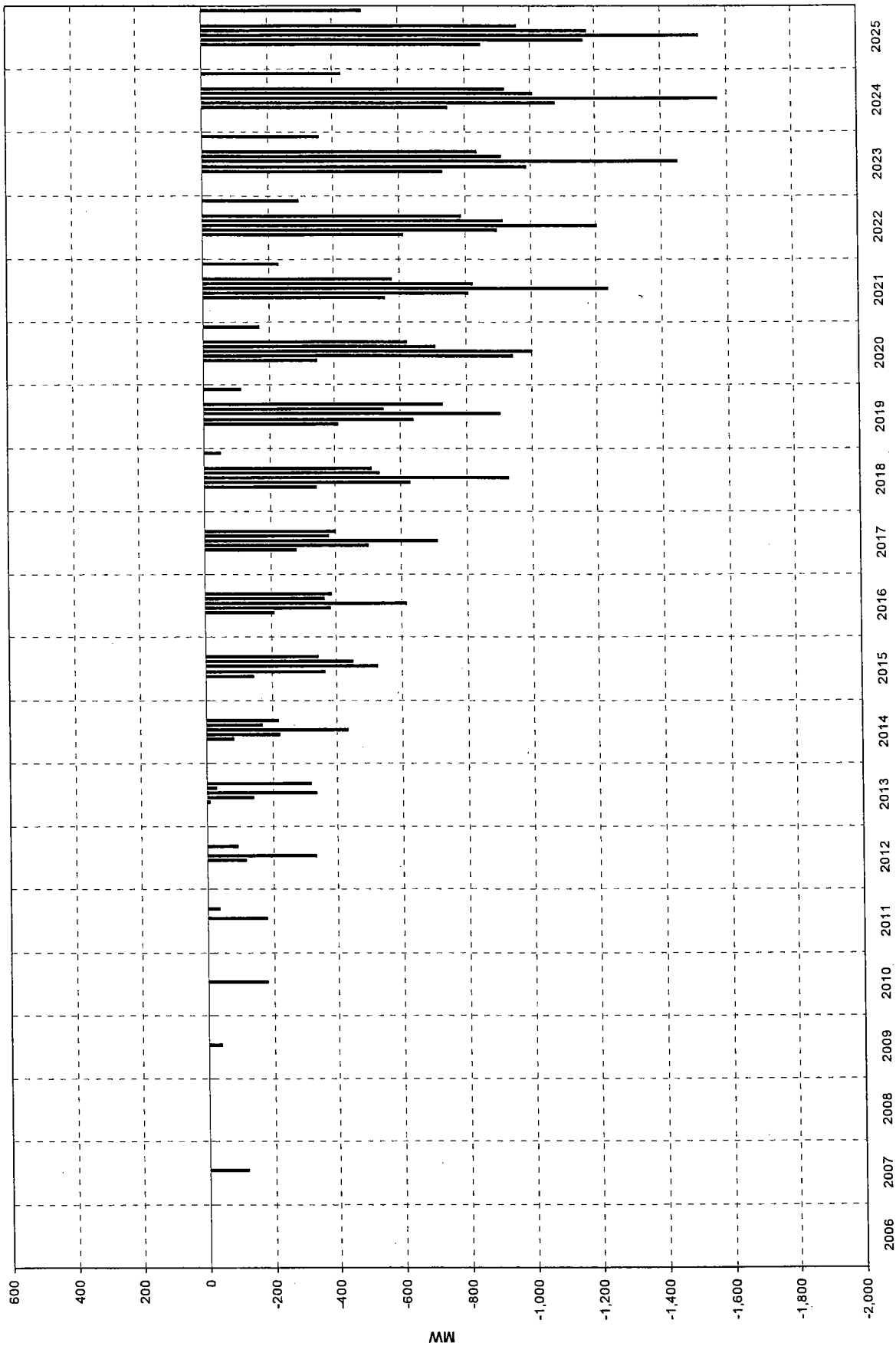

Exhibit No. 106
Case No. IPC-E-06-9
R. Sterling, Staff
10/10/06

STAFF EXHIBIT NOS. 107 THROUGH 117

CONTAIN CONFIDENTIAL INFORMATION

SUBJECT TO THE PROTECTIVE AGREEMENT

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 10TH DAY OF OCTOBER 2006, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING,** IN CASE NO. IPC-E-06-09, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

BARTON L KLINE
MONICA MOEN
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
(Confidential)

JAMES C MILLER
SR. VICE PRESIDENT, GENERATION
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
(Non-Confidential)

PETER J RICHARDSON
RICHARDSON & O'LEARY
515 N 27TH ST
PO BOX 7218
BOISE ID 83702
(Confidential)

DR DON READING
6070 HILL ROAD
BOISE ID 83703
(Confidential)

RONALD L WILLIAMS
WILLIAMS BRADBURY PC
PO BOX 2128
BOISE ID 83701
(Non-Confidential)

ROBERT D LOOPER
PRESIDENT
MOUNTAIN VIEW POWER INC
1015 W HAYS ST
BOISE ID 83702
(Non-Confidential)

SECRETARY