BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION



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| IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE LANGLEY GULCH POWER PLANT | ) ) ) ) ) ) | CASE NO. IPC-E-09-3 |

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

JUNE 19, 2009

ALLEGEDLY PROPRIETARY DATA HAS BEEN
DELETED FROM THIS DOCUMENT

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. My duties at the Commission include analysis of a wide variety of electric and large water utility applications.

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

A. There are several primary purposes of my testimony:

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

gas-fired base load plant,

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

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

4) To discuss the Company's Benchmark Resource proposal and the costs Idaho Power is requesting be approved as a Commitment Estimate,

5) To discuss the requirements of *Idaho Code* § 61-541 and whether Idaho Power has met those requirements, and

6) To make recommendations regarding recovery of costs associated with the Langley Gulch project.

Q. Please summarize your testimony.

A. My testimony begins by reviewing Idaho Power's 2006 Integrated Resource Plan (IRP), which is the Company's basis for contending that it needs to acquire a gas-fired base load plant. I also consider whether changes in loads, resources, fuel prices and other factors since the 2006 IRP still support a new gas-fired base load plant. Based on my reviews, I conclude that a gas-fired base load resource is needed.

Next, I discuss a variety of other options for addressing Idaho Power's load requirements, 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 base load 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 top-ranked proposals. Although I express concerns that Idaho Power did not permit any build and transfer proposals to be submitted, I conclude that the evaluation of the proposals that were considered was fair. I recommend that the Benchmark Resource proposal for the Langley Gulch project be accepted as the winning bid.

Next, I discuss the Company's Benchmark Resource proposal and the costs Idaho Power is requesting be approved as a Commitment Estimate. I identify components of the Company's proposed Commitment Estimate that I do not believe should be recoverable from ratepayers. I also discuss the requirements of *Idaho Code* § 61-541, and identify other components of the proposed Commitment Estimate that I do not believe are known with enough certainty to merit pre-approval under the new legislation.

Finally, I make recommendations about those portions of the expected project costs that I believe merit pre-approval. I recommend that an amount of $347.0 million plus AFUDC be pre-approved for recovery under *Idaho Code* § 61-541, and that all additional amounts spent on the project including transmission, up to a maximum amount of $376.6 million plus AFUDC be subject to future audit and prudence review once the costs are known and the plant begins providing service.

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:

**BACKGROUND**

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

A. On March 6, 2009, Idaho Power Company filed an Application requesting a Certificate of Public Convenience and Necessity (CPCN) authorizing Idaho Power to construct, own, operate, and maintain the Langley Gulch power plant (Langley Gulch or Project) and authorizing inclusion of the Project in Idaho Power's rate base. The Project is a natural gas-fired combined cycle combustion turbine (CCCT) generating plant with a nameplate capacity of approximately 330 megawatts. The Company proposes to construct the Project on a parcel of land on the south side of Interstate 84 in Payette County approximately four miles south of the town of New Plymouth, Idaho. Idaho Power commits to procure and construct the Project for an amount that will not exceed $427,400,000 which it terms a "Commitment Estimate." Idaho Power proposes that amounts incurred in excess of the Commitment Estimate would be subject to a "Soft Cap," that is, excess costs could only be included in rates if the Commission agreed the additional amounts expended were prudent and should be included in fair, just, and reasonable rates. As a part of this Application, the Company is requesting that the Commission's Order issuing the CPCN authorize Idaho Power to include the Project's prudently incurred costs for fuel, fuel storage, and fuel transportation for recovery through the Company's existing Power Cost Adjustment (PCA) mechanism.

**APPROACH**

Q. Please describe the approach you took in your review of the Company's Application.

A. I began my review by considering whether Idaho Power's need for power was sufficient to justify a new base load resource. I reviewed the Company's 2004 and 2006 Integrated Resource Plans (IRPs), its 2008 IRP Update, and information I received during planning meeting related to the 2009 IRP which will be submitted in December. I also reviewed updated load forecasts and load/resources balances provided by the Company in response to production requests. In my review, I also considered whether a gas-fired base load resource was the proper type of resource to pursue, and whether Idaho Power had adequately considered other options for meeting forecasted loads.

Next, I reviewed the RFP process conducted by the Company. I thoroughly reviewed the RFP and the RFP Evaluation Manual, including the price and non-price criteria used for scoring proposals. I reviewed each of the proposals that were submitted and examined the scores assigned by the Company's evaluation team. Both the busbar analysis and the Aurora analysis used by the Company to rank proposals and develop a short list were carefully scrutinized. Transmission studies, air emission studies, and various site analyses were also reviewed.

Next, I reviewed the Company's Benchmark Resource proposal. I examined contracts for purchase of the steam and gas turbines, as well as purchase of water rights needed for plant cooling. I reviewed the land purchase option, assessed the site's permitting status, and studied fuel storage, transport, and transportation agreements.

Next, I carefully analyzed the Commitment estimate proposed by Idaho Power. I checked whether costs included in the Commitment Estimate matched costs included in the Benchmark Resource proposal. I considered whether any costs added to the Commitment Estimate but not included in the Benchmark Resource bid were proper. I reviewed all of the underlying bases for each cost item in the Commitment Estimate, and proposed amounts to be included in either a "Hard Cap" or a "Soft Cap" based primarily on the certainty with which each cost item was known.

Finally, I reviewed the requirements of *Idaho Code* § 61-514 and the rate making treatment requested by Idaho Power. In addition, I considered the rate making treatment for fuel that will be needed by the plant.

In my review of the Application, I examined responses to 103 production requests of the Commission Staff, as well as an additional 123 responses to requests made by intervenors. Besides the numerous contracts, studies and analysis mentioned earlier, I reviewed presentation materials for the Board of Directors and management, meeting notes, and a great deal of correspondence related to the Langley Gulch project. I believe that Staff's review of Idaho Power's Application was deliberate, thorough and fair.

**NEED FOR POWER**

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

A. The need for a new base load generating plant can be traced back at least as far as the Company's 2004 IRP. That plan called for a 500 MW coal-fired resource in 2011. Joint ownership was suggested because Idaho Power's need was mostly seasonal. One alternative considered was a joint project with PacifiCorp to add another unit at the Bridger plant in Wyoming.

In its 2006 IRP, Idaho Power reassessed its need for new resources. The plan included more DSM, more purchases from PURPA projects and other renewables, and a transmission upgrade in 2012. In addition, the plan included a 250 MW pulverized coal base load resource in 2013 and a 250 MW advanced or clean coal-fired resource (integrated gasification combined cycle; IGCC) in 2017. Idaho Power and Avista went so far as to conduct a joint study to investigate possible alternatives for new coal-fired generation. In the meantime, however, concerns about the effects of fossil-fueled generation on climate change began to build. Public perceptions, expectations about future $CO_2$ policy, and the reluctance of the financial sector to support such a project led to a belief that new conventional coal-fired generation would be too costly, too risky, or politically infeasible. Avista was the first to abandon its investigations into new coal generation options, followed soon after by PacifiCorp and Idaho Power. Idaho Power's focus then shifted to gas-fired generation to satisfy its base load generation needs.

In 2008, Idaho Power updated its 2006 IRP. Exhibit No. 101 shows a comparison of the 2006 IRP preferred portfolio and the 2008 updated portfolio (Table 11). The 2012 entry listed as "Southwest Idaho CCCT" was the basis for the base load RFP in which Langley Gulch was selected.

Q. Are there any other factors that helped support the Company's need for base load generation in 2012?

A. Yes, there were several. Idaho Power had been anticipating a considerable amount of new PURPA project development coming online, both because numerous contracts had already been signed and because anticipation of higher avoided cost rates led to an expectation of many additional contracts. In addition, a significant amount of non-PURPA cogeneration development was expected. None of that cogeneration materialized, however, and the majority of PURPA projects with signed contracts during this time frame have also failed to come online.[1]

Another factor has been the Company's difficulty in adding planned amounts of geothermal to its portfolio. In a 2006 Request for Proposals, a bid from U.S. Geothermal was accepted to provide 45.5 MW and to have facilities online between October 2007 and January 2011. So far, only 13 MW have been developed, and contracts for the remaining amounts have not been executed. In 2008, Idaho Power issued another RFP seeking 50-100 MW of geothermal generation. Although several bids were made, no contracts have emerged from that RFP.

Another factor has been an anticipated shift in flow augmentation releases with water from the federal dams on the Snake River above Brownlee. As a consequence of a Biological Opinion dated May 5, 2008, the Bureau of Reclamation intends to shift its flow augmentation releases from Milner and the Boise basin from summer to spring. This shift in flow augmentation has been incorporated in Idaho Power's stream flow forecasts, Operating Plans, and its 2009 Integrated Resource Planning studies. The effect of the planned shift in

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[1] From 2005 to the present, PURPA QFs with a total capacity of 175.5 MW have signed contracts but have yet to come online. A total of 21.6 MW of signed contracts have been terminated during this same time period. Projects with a capacity of 107 MW have come online.

releases will be a loss of approximately 140 MWa of summertime energy.

Finally, Idaho Power cites the expression of interest from several possible new customers with large loads to locate in the Company's service territory. All of these factors, combined with the Company's most recent load forecast led to the 2012 base load RFP initially calling for between 250 and 600 MW of new generation, and the acceleration of the online date for the base load resource from 2013 to 2012.

Q. Has the Company prepared an updated load-resource balance to show whether a new base load resource is needed?

A. Yes, it has. Idaho Power uses two primary criteria in its planning to assess the need for new resources – one is based on energy needs and the other is based on capacity needs. The water and load conditions used to determine the energy and capacity needs that justified issuance of the 2012 Base Load RFP were 70th percentile water and load for average energy, and 90th percentile water and 95th percentile load for peak-hour capacity needs. After the 2006 IRP was released, a series of surplus/deficit spreadsheets were periodically updated to reflect known or expected changes in resources or loads and the associated impact on forecast surplus/deficit position. Annual surplus/deficit spreadsheets for energy and peak hour planning conditions from March 2008 are included as Exhibit No. 102. The load forecast used in these spreadsheets was from August 2007. Note that at the time these spreadsheets were prepared, the Company was expecting both energy and capacity deficits from 2008 onward.

Monthly average energy and peak hour surplus/deficits are shown in Exhibit No. 103, both with and without the Langley Gulch project included. Note that with the Langley Gulch project assumed in 2012, the Company still projects energy deficits in some summer months. Peak hour deficits, however, are nearly eliminated by Langley Gulch after 2012.

Q. Do you believe that a new base load plant is justified?

A. Yes, it is justified based on the information and analysis in Idaho Power's 2006 IRP and 2008 IRP Update, the Company's load-resource balance under various water and load conditions, and transmission constraints that limit its ability to import power during critical times of the year. However, significant changes have occurred since the Company's last IRP was prepared.

Q. What changes have occurred since the 2006 IRP and the 2008 IRP Update were completed?

A. One of the most obvious changes has been the economic recession. The economic conditions have likely stalled load growth expectations in nearly all customer sectors. In response to production requests, Idaho Power stated that in December 2008 it adjusted the residential and commercial sector load forecast to reflect a prolonged slowdown in housing and consumer spending. Residential new customer growth rates (initially forecast to decline until the first quarter of 2009) were extended by Idaho Power to continue the decline into 2010 and later rebound to the point of the original new customer forecast in 2011. On a total customer (new plus existing) basis, the Company's revised forecast returns to the same value as the original forecast in 2016. Commercial customer growth estimates were lowered consistent with adjustments made to the residential class. Use-per-customer forecasts were not modified from the original forecast.

In May 2009, the Company further revised its load forecast to incorporate changes in special contract forecasts. In addition, the Company updated the forecast to include all DSM program impacts as of May 2009, including new demand response programs for Irrigation, Commercial, and Industrial customers proposed in the 2009 IRP process. The Company's most recent load resource balance is shown in Exhibit No. 104. Page 1 of the exhibit shows the load resource balance based on energy planning criteria. Page 2 of the exhibit shows the load resource balance based on peak hour planning criteria. Exhibit No. 105 shows the amounts by which the load forecasts have been changed compared to forecasts included in the Company's 2008 IRP Update.

Utilizing the May 2009 load forecast, along with the forecast peak-hour DSM contributions and the assumed level of purchases from the Pacific Northwest, Idaho Power is still projecting peak-hour deficits during July of 2009 through July of 2012 of 40 MW,21 MW,91 MW, and 183 MW, respectively. From an average energy perspective, using the May 2009 load forecast along with the forecast DSM contributions to reduce average energy requirements and the assumed level of purchases from the Pacific Northwest, Idaho Power is still projecting average energy deficits during July of 2009 through July of 2012 of 397 MW, 418 MW, 465 MW, and 535 MW, respectively.

Idaho Power is reportedly working on developing a new load forecast, but does not expect it to be available until late summer of 2009. The Company states that the revised load forecast will be reflective of the most current economic forecast drivers, the most recent input from the Company's large power representatives and their contacts, energy efficiency impacts, and the latest forecast of retail electricity prices.

Q. Are there any other recent changes you are aware of that would affect Idaho Power's loads and resources?

A. Yes, there are a few. **This section of Staff's direct testimony contains confidential information subject to protective agreement.** In addition, on May 28, 2009 the Company made a filing to delay the start of the Hoku contract in 2009. As part of the agreement to delay the contract start, Idaho Power is requiring Hoku to reduce its July and August 2012 loads by 40 MW below the original limits in the contract. Idaho Power has also recently modified its Irrigation Peak Rewards Program to encourage greater participation. As a result of the program modifications, a much greater reduction in summertime loads is expected than was originally anticipated. Finally, the 2012 scheduled completion date of the Boardman to Hemingway project that is expected to add 255 MW of additional transmission capacity to the Northwest has been pushed back to 2015. These changes are reflected in Exhibit No. 104.

Q. With so much economic uncertainty right now, how can the Commission be certain that the proposed

Langley Gulch project is still needed?

A. With so much uncertainty, the Commission cannot be certain that the project will be necessary at exactly the online date planned by the Company. For projects with relatively long lead times, there will always be at least some uncertainty about whether the planned online date will exactly match the load growth forecasts. Load will almost always occur at a faster or slower rate than planned.

Q. What would be the consequences if it turned out that the online date of the Langley Gulch project could be delayed due to prolonged effects of the current recession or other factors?

A. If the planned online date of the plant was delayed, there would likely be costs, benefits and risks that should all be considered and weighed against each other. First, delaying the online date would likely cause Siemens to either charge cancellation fees (approximately $8.7 million for the gas and steam turbines), or negotiate contract extensions wherein Idaho Power would be responsible for increased costs. In addition, the Engineering, Procurement and Construction (EPC) contractor would likely increase its costs for labor, materials and other services due to inflation. The six month delay in online date already planned by

Idaho Power is estimated to cost $6.8 million in the Commitment Estimate. In addition to cancellation fees, penalties and inflationary increases, delaying construction could cause Idaho Power to incur higher costs to purchase replacement power, and would also likely cause Idaho Power to forego any revenues from surplus sales that the plant might be able to make if it were available.

On the other hand, delaying the online date would also cause some savings. Delaying a $427 million investment by one year reduces the project's net present value by roughly $23 million.

Q. Would there be risks in delaying construction if it were possible?

A. Absolutely. If the planned online date was delayed and it turned out that the plant was actually needed sooner, it could be just a cost risk if replacement power could be found. However, because Idaho Power is transmission constrained under high load conditions during certain times of the year, it may not be able to obtain replacement power at any price. Ultimately, the risk could be mandatory curtailments.

By comparison, the risks of bringing the plant online sooner than needed are completely financial. In fact, bringing the plant online earlier than needed could even be beneficial if certain load and market pricing conditions were to occur. In my opinion, the risks of an early online date versus a late online date are not symmetric. The costs and risks of bringing the plant online too late far outweigh the costs of bringing the plant online too soon.

Nevertheless, while there is no assurance that the plant will come online at precisely the optimum time, I do believe that the plant will still be needed in approximately the time frame planned. If normal load growth resumes and load forecasts return to pre-recession levels, there is some risk that the plant would not be available in time if construction were to be delayed now based on current load growth rates. Because construction of a CCCT has approximately a three-year lead time, the Company does not have the luxury of waiting to see how a recovery from the recession will unfold before making a decision when to proceed on development of a new generating resource.

Q. But given the uniquely high degree of uncertainty Idaho Power is currently faced with, do you think it is wise to make a decision now on such a major resource addition?

A. Ideally, Idaho Power would only have to make resource decisions when all factors are known.

Unfortunately, that is just not realistic. There will always be uncertainty, but perhaps current economic conditions make the uncertainty seem greater than it has been in the past. Doing nothing until there is more certainty is very risky and simply not an option in my opinion.

Q. In the 2012 Base Load RFP issued on April 1, 2008, Idaho Power was seeking proposals for between 250 and 600 MW of dispatchable energy. On June 25, 2008, the RFP was revised to request 300 MW. Why did Idaho Power revise the RFP to request a much smaller amount?

A. At the time the RFP was being prepared, Idaho Power was discussing plans with two potential new customers that could have added over 400 MW of new load to Idaho Power's system. If these customers' projects proceeded as anticipated, or if any other new customers with significant electrical loads decided to move into Idaho Power's service territory, Idaho Power was going to need more resources to serve the new load. With this in mind, the RFP was initially released with a quantity range indicating that Idaho Power anticipated acquiring between approximately 250 MW and 600 MW of dispatchable energy. Although discussion with the two companies continued, no final agreement was reached. Ultimately, Idaho Power elected to set the RFP quantity at approximately 300 MW due to uncertainty about the size and likelihood of potential new large loads.

After the release of the RFP, the economy continued its steep downturn. In hindsight, the decision to reduce the size of the RFP was probably a good one. The smaller size of the RFP significantly reduces the risk that loads will not recover enough in time to fully utilize the full capacity of the plant, and lessens the cost and risk if the plant's online date turns out to be earlier than needed.

Q. As proposed and evaluated in the RFP process, qualifying proposals were required to be capable of commencement of energy deliveries not later than June 1, 2012, yet the proposed Langley Gulch facility has an expected online date of December 1, 2012. Why is the project being delayed?

A. Idaho Power has explained that after the Benchmark Resource proposal was recommended as the winning bid, the Company's senior management questioned, given the current financial crisis, whether the project could be financed. The Company believed that the Benchmark Resource proposal would provide substantial cost savings for customers; consequently, management felt that the best way to preserve those cost savings was to defer the online date to see if the Commission was willing to provide ratemaking assurances that would enable the Company to finance the project in a way that would preserve the significant cost savings for customers.

Q. Do you believe it was a wise decision to delay the required online date of the project?

A. I was aware of the Company's concerns that it would not be able to finance a self-build project without certain ratemaking assurances from the Commission. Absent those assurances, I believe the Company thought it might not be able to obtain financing for the project. I also believe that the Company strongly wanted the Commission to be able to consider approval of a CPCN under legislation that was still pending at the time. It makes sense that the Company would want to wait until it was confident that the legislation would be passed before deciding whether to proceed with the self-build proposal. On the other hand, all other bidders were willing and able to meet the online date required by the RFP. Presumably they were confident they could finance their proposals without a delay in the online date. The need to delay the project's online date appears to only have been an issue for the Company's Benchmark Resource proposal.

**OTHER RESOURCE ALTERNATIVES**

Q. Do you believe that Idaho Power has adequately considered other alternatives to adding a new base load plant?

A. Yes, I do. As discussed previously, Idaho Power prepares an Integrated Resource Plan every two years as required by the Commission. Because of the plan's complexity, integrated resources planning has become an almost ongoing process. In the planning process, all new resource options are considered, including renewable resources such as wind, geothermal, and solar. Upgrades to existing hydro plants are also considered. New gas-fired thermal generation options, both simple cycle and combined cycle, are also on the menu of possible choices, as are clean coal options such as integrated gasification combined cycle (IGCC) and supercritical pulverized coal. Nuclear options are also considered for the outer years of the planning period. Finally, a wide variety of demand-side options are also considered.

Idaho Power's preferred resource portfolio already includes some of these generating resource options <u>in addition to</u> a base load gas-fired resource in 2012. An RFP for additional geothermal resources was issued in 2008 and an RFP for up to 150 MW of additional wind generation was issued on May 18, 2009, just one month ago. Clearly, Idaho Power is pursuing a variety of other generating resource options besides just gas-fired generation.

Q. Do you believe that PURPA projects (QFs) are a viable means of meeting future base load needs of Idaho Power?

A. No, I do not believe they can be planned on as a reliable option for meeting base load needs. 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. The majority of projects for which contracts have been signed in recent years have yet to come online and have had their contractual online dates extended. The recent substantial increase in avoided cost rates for PURPA projects will likely stimulate some new development, but the amount and timing of new projects is unknown. The timing and pace of PURPA development is not within Idaho Power's control and is not dictated by the Company's need for new generation.

Furthermore, because nearly all new QFs are wind projects, it is unlikely that they could prove to be an acceptable substitute for a new base load resource even if they could be timely developed. Because wind generation is intermittent, there is no guarantee that the generation would be available during all of the hours when it would be needed.

Q. Are market purchases a reasonable alternative for meeting future base load requirements?

A. Long-term market purchases or bilateral contracts with other utilities can be good options in some cases, but they require that transmission be available to import the energy. It might be possible to purchase a product from a marketer or another utility in the Northwest, 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 frequently subject to congestion, energy purchased at Mid-C cannot be used at all times to meet the load requirements of 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. Although such purchases may be available from time to time, long term reliance on east-side transmission capacity is probably not feasible at least until completion of the planned Gateway West project (a 500 kV transmission line across southern Idaho and Wyoming). I do not believe it would be wise to rely on east-side purchases indefinitely to meet either base load or 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 Idaho Power's system would 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 Idaho Power could, do you believe it would be wise for the Company to rely on the market to meet its base load needs?

A. Even if Idaho Power could rely on the regional power market as an alternative to building new generation, I believe 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.

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 a new base load power plant?

A. I would characterize transmission upgrades as a necessary component, rather than an alternative, in Idaho Power's plans to meet future load requirements. 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. Idaho Power also completed an upgrade of the Borah-West path in May 2007. This upgrade increased the Borah-West transmission capacity by 250 MW. The increased transmission capacity is available to serve Idaho Power's native load requirements with new generating resources located east of the Borah-West constraint (eastern Idaho). Even with these improvements, however, Idaho Power's transmission system is still constrained at certain times for imports of energy from the Pacific Northwest.

In its 2006 IRP and 2008 IRP Update, Idaho Power has expanded its analysis of possible transmission projects, associated costs, and potential risks. Based on its analysis, the preferred portfolio incorporates a transmission upgrade from northeast Oregon to southwest Idaho. Called the Boardman to Hemingway project, the 500 kilovolt (kV) transmission line would increase transmission capacity from the Northwest by 225 MW. In addition, Idaho Power and PacifiCorp are proceeding with the Gateway West project, a plan to build more than 1,000 miles of 500-kV transmission lines across Wyoming and southern Idaho.

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

A. A diverse resource portfolio should include cost effective energy conservation. Conservation is part of Idaho Power's resource planning strategy. The Company has several DSM programs that have been underway for many years. Other programs have been recently expanded or modified, while a few new programs are just now being introduced. The programs are aimed at both energy savings as well as peak demand reduction. Programs are available for all customer classes.

For long-term planning of energy conservation and demand response programs Idaho Power relies on the IRP process, consultation with its Energy Efficiency Advisory Group and participation in regional energy efficiency organizations. The goal of the processes is to identify opportunities, evaluate them, and pursue all of those that are cost-effective.

Staff believes that Idaho Power has strengthened its commitment to achieving all cost-effective energy efficiency and demand response potential. The Company primarily uses the tariff Schedule 91 Energy Efficiency Rider (Rider) to fund DSM programs. Recently, the Commission in Case No. IPC-E-09-05, Order No. 30814 increased the Idaho Rider from 2.5 percent of base rate revenues to 4.75 percent. The increase is intended to fund new and expanded energy efficiency and demand response programs as well as address a negative balance in the Rider account.

Conservation programs of the past, as well as programs planned and underway now, have certainly proven that energy usage can be reduced cost effectively. However, even the most successful conservation programs have historically been unable to keep pace with the increasing load growth that must be met. In my opinion, conservation programs by themselves cannot achieve enough demand reduction to realistically satisfy the Company's immediate need to meet growing loads.

Q. Do you believe that the other resource alternatives that you just discussed can collectively substitute for a new base load 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 some opportunities for increased efforts as more options become cost effective, particularly with regard to conservation and demand response, but I believe a new base load resource is still necessary.

**OVERVIEW OF THE REQUEST FOR PROPOSAL PROCESS**

Q. Please provide a brief overview of the request for proposals (RFP) issued by Idaho Power.

A. As called for in its 2006 IRP, Idaho Power issued the RFP on April 1, 2008. The RFP sought proposals for between 250 and 600 MW of dispatchable energy. The RFP specified that only power purchase agreements (PPAs) or tolling agreements (TAs) to supply firm or unit contingent energy would be considered. Projects were required to commence energy deliveries not later than June 1, 2012. At a minimum, proposals were required to include a 15-year term with at least one 5-year contract renewal option; however, different contract terms and options were encouraged.

Q. What did the RFP say with regard to participation by Idaho Power or its affiliates?

A. The RFP specified that proposals from any Idaho Power affiliates would not be accepted. However, it also clearly stated that Idaho Power would submit and evaluate a natural gas-fired combined cycle combustion turbine (CCCT) to be constructed by Idaho Power as one of the resource alternatives. This proposal was designated as the Benchmark Resource.

Q. Did the RFP specify the types of generating resources that would be considered?

A. No, it required only that proposals use commercially viable dispatchable technology. Nevertheless, I think it was quite clear that the Company was seeking proposals for gas-fired CCCTs. First, the RFP was designated as a "base load RFP." It also referred to the 2006 IRP's initial identification of the need for coal-fired base load generation and the Company's subsequent decision to pursue the development of a gas-fired CCCT instead. The requirement that the project be dispatchable eliminated just about all technologies except gas-fired generation.

Q. Did the RFP specify where proposed projects must be located?

A. No, but it did make clear that the preferred point of delivery was a direct connection with Idaho Power's transmission system near the Treasure Valley load center.

Q. Why did Idaho Power amend its RFP from an initial request of from 250 to 600 MW down to a request of up to 300 MW?

A. Although the RFP initially stated that Idaho Power anticipated acquiring between approximately 250 MW to 600 MW, it made clear that the higher amount would be used to serve potential new load and that a final decision on the quantity sought would be made later. On June 25, 2008, Idaho Power issued an addendum reducing the RFP requested quantity to approximately 300 MW. The Company indicated that the lower amount was based on a revised assessment of its needs and its discussions with companies proposing new large loads.

Q. What is a tolling agreement (TA)? How does it differ from a power purchase agreement (PPA)?

A. In the electric industry, a tolling agreement is an arrangement in which fuel is purchased by the utility and delivered to a non-utility owned plant, then burned or "converted" to generate electricity in exchange for a pre-established tolling charge. The utility may be responsible for procuring the fuel and arranging for its delivery, and is required to assume all price risk associated with its purchase. The power plant owner must own and maintain the plant, and operate according to a schedule determined by the utility.

In a power purchase agreement, the utility does not own the plant and is not responsible for purchasing the fuel or arranging for its delivery. All fuel price risk is normally assumed by the plant owner. The utility is able to dispatch the plant, and energy is purchased at an agreed upon price.

Q. The RFP stated that all bids would be compared to a "Benchmark Resource" proposal. What was the Benchmark Resource proposal?

A. The Benchmark Resource was a proposal made by a team of Idaho Power's own employees for a CCCT to be constructed by the Company. The RFP did not divulge any details of the Benchmark Resource, including its size, where it would be located, or the exact type of equipment it would use. At the time the RFP was issued, it was my understanding that although development of the Benchmark Resource proposal was already underway, it was still a work in progress. Because the Benchmark Resource proposal was ultimately selected as the winning proposal, I will discuss it in much more detail later in my testimony.

Q. Do you believe utilities should permit self-build proposals to be made in RFPs?

A. Yes, in most cases. As long as the utility has the resources and experience to carry out its proposal, I believe it should be allowed to compete with other bidders. In some cases the utility may be able to make a proposal that is less costly and better suited to meeting the needs of its customers. To prohibit self-build proposals would be to deny ratepayers an opportunity for possibly the best project at the lowest cost.

If self-build proposals are allowed in RFPs, however, I also believe that safeguards should be in place to guard against impropriety. The RFP process should insure that the utility does not have an unfair advantage and that all proposals are evaluated fairly.

Q. Why was the RFP restricted to only power purchase agreements and tolling agreements? Why were build-and-transfer proposals not allowed?

A. The Company's reasons for not allowing build-and-transfer proposals are discussed in the direct testimony of Idaho Power witness Bokenkamp. In short, the Company believed that it would have needed detailed design specifications in order to eliminate significant design differences between proposals and to avoid a complicated and subjective evaluation process. The Company believed that, due to its earlier decision to accelerate the online date from 2013 to 2012 and the lead-time required for obtaining major equipment, the

Company did not have enough time to prepare a detailed design specification and release the RFP in time to meet the 2012 online date.

Q. Do you believe Idaho Power's rationale for not allowing build and transfer proposals is reasonable?

A. I understand the Company's concerns about needing detailed design specifications in order to insure that the Company would receive quality equipment, exactly the design features it wanted, and that the facility was easy to operate and maintain. I also understand the advantages of having direct control over project design and construction, and the possible difficulties that might be encountered in proposal evaluation if proposals contained design differences. Nevertheless, by not allowing build-and transfer proposals, Idaho Power may have locked potential bidders out of the process and ultimately denied ratepayers of the possibility of a high quality, lower cost plant.

Although I understand the timing difficulties explained by Idaho Power, I think the excuse of not having time to prepare detailed design specifications is a weak one. Construction of a new base load plant has been anticipated for many years, and it was no surprise that a project of this size and type would have a long planning and construction lead time. The project has a

20-year net present value of roughly $2.7 billion and will be expected to be in service for 35 years. Given the magnitude of the project, I do not think it would have been unreasonable for Idaho Power to have built several additional months into its RFP schedule for detailed design specifications to be prepared so they could be used as the basis for build-and transfer proposals. Much of the time Idaho Power may have "saved" during the RFP stage by not preparing a detailed project design will be made up later when detailed design work must be done before construction begins. Moreover, the Company ultimately delayed the project online date for other reasons.

Q. Do you believe that build-and-transfer proposals would have been submitted if the RFP would have allowed them?

A. Yes, I do. I was personally contacted by two potential bidders who expressed concern and frustration that the RFP was not allowing build-and-transfer proposals to be submitted. Other Staff were contacted by two additional bidders expressing similar concerns. The potential bidders stated that their business is building new power plants, not owning and operating them. Unless they could partner with another entity willing to own and operate the plant, they could not participate in the RFP.

Rather than seeking a partner, they indicated that they would probably choose to not even submit a bid. It is difficult to be reassured that the winning proposal in the RFP is the best proposal if some interested bidders chose to not submit bids because they were shut out of the process by the Company.

Q. Do you know of any other concerns that potential bidders may have had that caused them not to participate?

A. Yes, one potential bidder who contacted me was concerned that Idaho Power was allowing a self-build proposal to be submitted. Their concern was that the RFP process might be a sham just to satisfy Commission requirements, and that in the end, Idaho Power would select its own self-build proposal regardless of any other bids that might be submitted.

Q. Do you know for sure whether any of the bidders who contacted Commission Staff ultimately decided not to submit bids?

A. No, I do not. In fact, Staff never asked any of the potential bidders who expressed concerns to identify themselves, so it would have been impossible to know whether they submitted a bid. I do know, however, that not all of the potential bidders who attended the Pre-Bid conference submitted bids.

Q. Idaho Power stated that it hired RW Beck as an independent consultant to assist with the RFP. What role did the consultant play?

A. The RFP informed bidders that Idaho Power planned to use RW Beck Inc. as an independent consultant to help ensure that the RFP was conducted fairly and properly and that all offers were treated objectively and consistently. Possible tasks of the independent consultant were listed as follows:

- Consult with Idaho Power in preparing the RFP and evaluation criteria.
- Consult with Idaho Power on evaluation of proposals;
- Independently score all or a sample of the proposals to determine whether the selection of the short-list is consistent with the scoring criteria.
- Compare the results of the independent consultant's scoring with Idaho Power's scoring and work with Idaho Power to attempt to reconcile and resolve scoring differences.
- Prepare reports as requested by Idaho Power including reports to the Idaho and Oregon Commissions as requested by Idaho Power.

Q. Did the independent consultant perform all of the possible tasks that were identified?

A. No, R.W. Beck was only used to assist in preparing the RFP and evaluation criteria, and to provide guidance to the evaluation team. R.W. Beck was not asked to independently score any of the proposals because of cost considerations and the likelihood in the Company's estimation that it would simply duplicate the scores of Idaho Power.

**Proposals**

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

A. Idaho Power received proposals from six bidders by the October 17, 2008 RFP deadline. One proposal was immediately rejected because the bidder failed to submit a Notice of Intent to Bid as required by the RFP. The remaining five bidders proposed 13 alternative projects, differing primarily by generating technology, equipment, project configuration and location. All of the proposals were for either gas-fired simple or combined cycle projects. Obviously, one of the bids was the Benchmark Resource proposal. Only one of the alternatives was for a PPA. That proposal was eliminated during the initial screening stage, however, for not meeting the requirement to deliver energy and capacity to Idaho Power's system. Except for the Benchmark Resource proposal, all of the remaining proposals were for tolling agreements. Each project proposed, by itself, would have satisfied Idaho Power's need for approximately 300 MW, and none would have needed to be combined with other projects or proposals.

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. As I stated earlier, I have concerns that some potential bidders may have chosen to not participate because the RFP did not solicit build-and-transfer proposals or because of concerns that all proposals would not be evaluated fairly. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

I would have certainly liked to see more bidders participate. There were fewer bids received in this RFP than in previous RFPs for the Bennett Mountain and Danskin projects. Obviously, more bids would have increased the chances that a proposal superior to the Company's Benchmark Resource proposal would have been selected.

The fact that only one PPA proposal was

submitted is neither surprising or of much concern to me. Few developers are willing to take all of the gas price risk for such fuel intensive projects, especially given the length of the proposed agreement and the historical volatility of natural gas prices.

Of the bids that were submitted, however, all of them were made by qualified developers. Furthermore, in my opinion, all of the bids that made it to the final round of screening were extremely competitive.

Q. Do you believe that Idaho Power's Benchmark Resource proposal had an advantage over other proposals?

A. I do not believe that it had an actual advantage, but I definitely believe there was a perception amongst some prospective bidders that it did have an advantage. At the Pre-Bid Conference, some bidders expressed concern that Idaho Power's Benchmark Resource proposal had an advantage over other potential bids because the Company had already made reservation agreements with Siemens for gas and steam turbines. The reservation agreements required a deposit of $8.7 million to Siemens that would be forfeited if Idaho Power canceled the equipment reservation or did not assign the equipment to someone else. Idaho Power informed potential bidders that it would not be willing to allow another bidder to purchase the equipment from the Company if that other bidder's proposal was selected in the RFP. By locking up equipment before the RFP was issued, Idaho Power was taking a risk that it would lose its deposit if it was not the winning bidder. Other potential bidders were not willing to make such a large potentially nonrefundable deposit. Some felt that they would be at greater risk of losing an equipment deposit because Idaho Power could argue that the deposits were necessary regardless of whether they made the winning bid and that the Company could seek recovery of lost deposits through the Commission.

I do not believe that the potential bidders' concerns were warranted because Idaho Power did not obtain any cost advantage by reserving equipment early, nor were any points awarded in the proposal scoring for having reserved equipment. Nevertheless, I think some other potential bidders had a perception that Idaho Power's self-build proposal had an advantage from the start, which may have deterred some of them from participating.

**Evaluation of Proposals**

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 eight employees from various business units of the Company, including Power Production, Planning, Operations, Finance, River Engineering, and Pricing and Regulatory Services. In addition, advisors from the Company's Legal Department and R.W. Beck, 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 R.W. Beck, 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.

Idaho Power used a three-stage screening process in evaluating bids. In the first stage, proposals were examined for responsiveness and to verify that all minimum requirements set forth in the RFP had been adequately addressed. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

In the second stage, proposals were compared and ranked strictly on a cost basis to determine if any were substantially more expensive than the others. The objective at this stage was not to provide a precise indication of the potential value of the proposals, but rather to provide a good relative comparison of the proposals to each other. Cost comparisons were made between proposals based on the information provided in the bids and on other costs deemed by Idaho Power to be assignable to each proposal. Both fixed and variable costs were included, and costs were calculated at various assumed capacity factors. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

At the Stage 3 screening level, price and non-price factors were scored for each proposal using a weighted scoring system. The factors along with the maximum scores allocated to each category are summarized below:

**PRICE CRITERIA (60 POINTS)**

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| | |
|---|---|
| Total | 60 points |

**NON-PRICE CRITERIA (40 POINTS)**

| | |
|---|---|
| A. Project Development | 8 points |

| | | |
|---|---|---|
| B. | Project Characteristics | 8 points |
| C. | Product Characteristics | 8 points |
| D. | Project Locations | 8 points |
| E. | Environmental | 8 points |
| F. | Credit Factors & Financial Strength | 8 points |
| Total | | 40 points |

**This section of Staff's direct testimony contains confidential information subject to protective agreement.**

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 each member of the team awarded a score to each proposal in each non-price category. All team members' scores for all factors were then averaged for each bid. The process was repeated following face-to-face meetings between the team members and the bidders.

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. Some of the non-price criteria required subjective judgment in point factoring, but that is difficult to avoid.

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

A. Yes, I believe they were made very clear. The RFP informed prospective bidders that price factors would comprise 60 percent of the evaluation criteria and non-price would comprise 40 percent. In addition, the RFP included a list of all of the non-price factors that would be considered. Exhibit No. 106 is a copy of the scoring criteria that was included in the RFP.

In some cases, additional explanations and cautions were provided to inform potential bidders of special concerns. For example, the RFP included the following warnings: "Idaho Power is concerned about the impact of degradation of air quality in the Treasure Valley on the long-term availability of energy from generation projects developed in the Treasure Valley. Proposals using generation resources, located in Ada or Canyon Counties, will be stringently scrutinized and may not receive full points for this category. The Company will also consider whether community opposition to a proposed generation facility will delay the completion of necessary facilities."

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 for each bid that was submitted.

Q. Did the RFP inform bidders of the likely transmission constraints that might be encountered based on where projects might be located?

A. Although no specific transmission cost information was included, the RFP did inform bidders that the preferred point of delivery for power is a direct interconnection with Idaho Power's transmission system, located near the Treasure Valley load center. In addition, the RFP made clear that most of Idaho Power's long-term rights to transmission are already dedicated to existing resources. Respondents were directed to assume that Idaho Power has no un-utilized, long-term firm transmission rights that are available to be re-directed to transmit proposed resources to Idaho Power's service territory.

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

A. Idaho Power initially proposed to use the 2007 median forecast of the Northwest Power and Conservation Council. However, believing that the forecast was low compared to prices at the time, Idaho Power revised the forecast to include substantially higher prices. A copy of the revised forecast was available to all prospective bidders as an addendum to the RFP. Gas prices were assumed to be $9.39 per MMBtu in 2012 and were escalated to $14.29 in 2030. In its sensitivity analysis of short-listed proposals, Idaho Power used a high gas forecast in which prices were assumed to be 150 percent of expected, and a low forecast in which prices were 50 percent of expected.

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 (i.e. higher efficiencies) had lower fuel costs on a cost per MWh basis. In the Aurora analysis, more efficient units were dispatched more often than less efficient ones under all gas price scenarios. Consequently, more efficient units were also able to generate more energy for surplus sales to the regional market, and thus had lower overall costs at both high and low gas prices. As a result, the price ranking of the short-listed proposals remained the same under all price assumptions.

**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 proposals from two bidders and the Benchmark Resource team were short-listed and meetings with representatives of the short-listed entities were held in January 2009. Through these meeting and follow-up phone calls and correspondence, Idaho Power was able to clarify bids, such as definitively determining what things were or were not included in the bid. All short-listed bidders were permitted to refresh their bids following meetings with Idaho Power's evaluation team. Final negotiations were pursued with all three of the short-listed bidders.

**Analysis of Final Candidate Proposals**

Q. Please briefly describe the projects that made the final short list.

A. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

Idaho Power's Benchmark Resource proposal was also one of the short-listed finalists. I will discuss that proposal in more detail later in my testimony.

Q. How did the overall scores compare for the two top-ranked proposals?

A. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

Q. Please explain the top half of Exhibit No. 107.

A. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

**Q. This section of Staff's direct testimony contains confidential information subject to protective agreement.**

**LANGLEY GULCH PROJECT DESCRIPTION**

Q. Please describe the Benchmark Resource plant.

A. The proposed Langley Gulch plant would be a natural gas-fired CCCT plant with a nameplate capacity of approximately 330 MWs. The facility would be located on the south side of Interstate 84 approximately four miles south of New Plymouth. The proposed project's combustion turbine is a single Siemens SGT6-5000F. The plant would also include a Siemens SST-900 steam turbine. The plant would be water-cooled and be equipped with state-of-the-art emission control equipment.

**Operation**

Q. Please describe the expected operation of the proposed Langley Gulch plant.

A. If approved, the Langley Gulch plant will be operated as a base load facility to serve Idaho Power's load. However, when it is not needed to meet the Company's own load, it would be economically dispatched to make surplus sales whenever it could do so profitably. The opportunity for sales of surplus energy will depend on the difference between the market price of power and the Langley Gulch plant's cost of production. Because Langley Gulch is a very efficient state-of-the-art combined cycle plant, its dispatch cost is lower than many combined cycle plants in the region; consequently, it may frequently be cost effective to operate the plant to make off-system sales. In the Aurora analysis of the proposal, annual capacity factors ranging from 50 percent in 2013 to 75 percent in 2031 have been computed. The plant is currently scheduled to be online in December of 2012.

**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 prior to full inclusion in base rates. 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 were handled for the Bennett Mountain and Danskin plants prior to full inclusion in base rates. After normalized fuel-related costs are included in base rates, only extraordinary fuel costs will flow through the PCA.

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

A. The location of the proposed Langley Gulch project is approximately three-fourths of a mile from the Williams Northwest Pipeline. A short interconnection pipeline will be constructed as part of the project. Idaho Power has not yet negotiated or entered into any agreements for the purchase of natural gas fuel supplies for the proposed plant.

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

A. Idaho Power already has several gas transportation and storage agreements in order to provide gas to its other gas-fired plants. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

Q. How does Idaho Power plan to 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 its Risk Management Policy.

Idaho Power also has gas hedging guidelines for its existing gas-fired plants (Evander Andrews/Danskin and Bennett Mountain). If the new Langley Gulch 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 its gas-fired plants. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

Because it is a base load plant that is expected to operate at a relatively high capacity factor, fuel costs for the Langley Gulch plant will be substantial. A well-planned and executed hedging strategy and risk management plan will be crucial to managing fuel price risk in the future.

**Water Supply**

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

A. Water would be used by the plant primarily for evaporative cooling, which is normally only required in the summer months. Water would be supplied with water from the Snake River. This will require a pumping station and an 8-mile pipeline. Idaho Power has already paid $2.2 million to purchase a water right to secure water for the plant. Construction of the pipeline has been estimated to cost $8.1 million.

**Electrical Interconnection**

Q. What transmission work would have to be done in order to interconnect the proposed plant?

A. The site is relatively close to existing transmission facilities. As planned, the Langley Gulch plant would be connected to the existing Ontario-Caldwell 230 kV line located 2.5 miles away. It would also be looped to connect to a tap approximately three miles from Caldwell via construction of a new 18 mile 138 kV line. The total cost for the transmission work is estimated at $22.1 million. At this point, costs are estimated based on a system impact study and are considered accurate to within plus or minus 20 percent. Detailed costs would be developed in a Design Study.

**Project Permits**

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

A. 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 reported that the Permit to Construct application is in draft preparation and is expected to be submitted in June 2009.

Idaho Power's air quality consultant has modeled air quality impacts for the Langley Gulch site **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

Q. Will other permits be required?

A. Yes, other major permits include a Comprehensive Plan change from Payette County, a Right-Of-Way permit from BLM for transmission and water lines, a Stream Alteration permit and a Water Quality Certification from the Corps of Engineers, a Groundwater Injection permit from the Idaho Department of Water

Resources, and miscellaneous construction permits. There do not appear to be any insurmountable obstacles in obtaining permits to construct and operate the plant.

**Project Risks**

Q. What are some of the risks associated with the Langley Gulch project?

A. One risk is simply the risk associated with using natural gas for fuel. As evidenced by the past year, gas prices can be extremely volatile. The project would increase the amount of gas-fired generation in Idaho Power's fleet to over 700 MW. Nevertheless, whether Idaho Power chose the Benchmark Resource proposal or one of the tolling agreements submitted in the RFP, it would face the same risk.

However, by choosing the Benchmark Resource proposal, Idaho Power will face some risks that it would have avoided with a tolling agreement. First, by being the owner and operator of the plant, Idaho Power will be responsible for any ongoing capital investment that may be required to keep the plant operational, and for any O&M costs that exceed project estimates. Second, there are potential construction-related risks, perhaps due to delays or liquidated damages, that Idaho Power could be responsible for by constructing the plant itself. Third, by being the project owner, the Company may be liable for equipment failures or decreases in heat rate that occur after equipment warranties expire. Finally, there is the risk that Idaho Power will not be able to obtain financing construction of the plant. This issue is discussed in more detail in the testimony of Idaho Power witness Smith and Staff witness Carlock.

**Project Benefits**

Q. Besides the advantages of the Benchmark Resource proposal that were considered in the scoring and ranking of proposals, are there any additional benefits to the Langley Gulch project?

A. All of the tolling proposals considered in the RFP were for only 20 year terms, and only the 20-year costs and benefits of the Benchmark Resource proposal were considered in the ranking and scoring of proposals. However, the Langley Gulch project is expected to have a useful life of 35 years. Consequently, there are an additional 15 years of residual value to the plant that was not accounted for in the evaluations. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

**COMMITMENT ESTIMATE**

Q. Idaho Power has proposed a Commitment Estimate of $427 million. Please discuss the items that make up the $427 million.

A. Exhibit No. 108 shows a breakdown of costs included in the Commitment Estimate. Idaho Power has already signed contracts with Siemens for the gas and steam turbine equipment following competitive bids by capable turbine manufacturers. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

All of the items from lines 22 through 32 are estimated costs, which with few exceptions have yet to be incurred. Transmission costs associated with building a new transmission line and interconnecting the plant are shown on line 51 ($22.1 million). The estimated costs of financing the plant (AFUDC) are shown on line 55 ($49.3 million). I will discuss the remaining items (lines 36-38 and lines 42-47) in more detail below.

Q. Please discuss the items on lines 36-38 of the

Commitment Estimate shown in Exhibit No. 108.

A. As I discussed earlier in my testimony, Idaho Power decided to delay the proposed online date of the project from June 2012 to December 2012. In turn, the scheduled start of engineering and construction was also delayed. As a condition of agreeing to delay the start of construction, the EPC contractor required Idaho Power to accept responsibility for any increases in labor in the interim (up to 2% of the original labor component) **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

Q. Please discuss the items on lines 41-47 of the Commitment Estimate shown in Exhibit No. 108.

A. The costs shown on line 42 is the estimated cost to construct a gas line tap to the Williams Northwest pipeline and to install a gas meter. Idaho Power informed all bidders that it would assume these costs and that bidders did not need to include them in their bids. Line 43 represents the costs incurred by Idaho Power's Benchmark Resource team in preparing its proposal. Line 44 is an estimate of the cost of fuel that will be required during start-testing and commissioning of the plant. Line 45 is an estimate of the cost of transmission upgrades that have been recommended to improve the transmission system but that are not required to integrate the Langley Gulch plant. Line 46 is a 20 percent contingency for transmission costs. The transmission estimate included in the Benchmark Resource bid was deemed to be accurate to within plus or minus 20 percent, so the 20 percent contingency was not included in the original bid. The "sub-synchronous resonance" (SSR) Study/Implementation cost of $1 million included on line 47 refers to analysis Idaho Power believes it will need to do to determine whether the Langley Gulch facility will cause potentially harmful interactions with other parts of the Company's transmission system.

Q. Please discuss the "Soft Cap" proposed by Idaho Power.

A. The Company has proposed that the Commitment Estimate be treated as a "Soft Cap." Idaho Power proposes that all costs up to the $427 million Commitment Estimate be pre-approved under *Idaho Code* § 61-541 and that any costs above this amount be brought before the Commission for specific approval.

Q. Do you believe the Commission should allow in the Commitment Estimate all of the costs requested by Idaho Power?

A. No, I do not.

Q. What guidelines do you believe the Commission should follow in determining an appropriate Commitment Estimate amount?

A. I believe that only those costs that are known with reasonable certainty and based on a competitive procurement process be approved for recovery under *Idaho Code* § 61-541. Approximately three fourths of the cost items in the Commitment Estimate are known with certainty and competitively procured. Contracts have been signed with Siemens Power Equipment for the gas and steam turbines, and an EPC contract has also already been signed for a specific amount. Other amounts included in the Commitment Estimate are based on estimates and contingencies, and are not known with enough certainty to be included in a Commitment Estimate. While some of the estimated costs will almost certainly be incurred, I do not believe they should be subject to pre-approval under *Idaho Code* § 61-541. Estimated costs and contingencies should be subject to the usual rigorous prudence standards to which other utility investments are held.

Q. Do you believe that a Soft Cap, regardless of the amount, offers sufficient protection to ratepayers that costs will be controlled?

A. No, I think it is also necessary to establish an absolute "not to exceed" amount, or Hard Cap, to protect ratepayers in the event extreme costs must be incurred to complete the plant and make it operational. If unforeseen circumstances were to occur and costs were to balloon out of control, Idaho Power should not be allowed to present an endless parade of cost approval requests to the Commission claiming that unless the additional investment is made, the plant cannot come online and all investment up to that point is wasted. A Hard Cap will provide incentives for the Company to contain costs and manage the project efficiently.

Q. How do you propose to establish a "not to exceed" or Hard Cap limit?

A. I propose that a Hard Cap be established that is equal to the expected project cost plus a reasonable contingency for those portions of the project cost that were based on estimates.

Q. Please discuss how you propose to determine an appropriate Commitment Estimate amount. Please specifically identify any amounts you propose not to include in the Commitment Estimate and explain why you propose to exclude them.

A. My recommended Commitment Estimate amount is shown on Exhibit No. 109. On the right side of the exhibit, I have shown three primary columns. In the leftmost column, I have simply reproduced the Commitment Estimate proposed by Idaho Power. The middle column labeled "Soft Cap" shows my recommendations for a commitment estimate. The right hand column labeled "Hard Cap" is my "not to exceed" recommendation.

Within each primary column for the Soft Cap and the Hard Cap, I show a percentage amount that I recommend should be allowed. For example, I recommend that 100 percent of the gas turbine, steam turbine and EPC contract amounts be included in the Soft Cap and Hard Cap because there is a signed contract and these amounts are known with certainty. Similarly, any other amounts that are known with certainty I recommend be included at 100 percent. This would include site procurement on line 18, NEPA permitting on line 20, Air Permitting on line 21, Transmission/Network study costs on line 27. Capitalized property tax is included on line 30 as it is a certain expenditure but the actual amounts will vary based on property valuations and levy rates. I have included water right costs on line 19 at the exact contract amount I was able to verify, which is slightly less than the amount Idaho Power included in its Commitment Estimate amount.

In the Soft Cap column, I have included many items at only 50 percent of the amount estimated by Idaho Power. I am assuming that the accuracy of the estimates for these items is plus or minus 50 percent. For example, the engineer's report used as a basis for the water line construction shown on line 22 states the following:

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Q. It appears that some of the costs included in the Company's Commitment Estimate amount are due to delaying the project's planned online date from June 2009 to December 2009. Please explain these costs.

A. Idaho Power has added amounts it labeled "Commitment Estimate Contingencies" to its Commitment Estimate. These are the amounts shown on lines 36-38 of Exhibit No. 109 that I described previously.

Q. Do you believe that any of these costs should be recoverable?

A. First, we cannot be certain that any of these costs will actually be incurred. However, if they are, because these costs were solely due to Idaho Power delaying the project's online date by six months, I do not believe they should entirely be the responsibility of ratepayers. All bidders were expected to be able to meet a June 1, 2009 online date, and as far as I know, all of them were willing and able to meet that date. Concerns about financing was the reason given by Idaho Power for the delay, yet this appears to only have been an issue with the Company's Benchmark Resource proposal. As a result, I do not believe these costs should be included in either the Soft Cap or the Hard Cap.

Q. Do you believe that "RFP Team Expenses" (line 43) should be included in the Commitment Estimate?

A. The team that prepared the Company's Benchmark Resource proposal undoubtedly has incurred costs and will likely continue to incur additional costs, although I cannot confirm the amounts. In any case, this is a cost that should not be included in either the Soft Cap or the Hard Cap. Other bidders would have had to include these costs in their bid amount, so it would be unfair for Idaho Power to exclude them from the Benchmark Resource bid during the evaluation process, but add the costs to its Commitment Estimate after it determined that the Benchmark Resource was the winning bid.

Q. What is your recommendation regarding start-up test fuel shown on line 44 of Exhibit No. 109?

A. I recommend that none of the costs of start-up test fuel be included in either the Soft Cap or the Hard Cap. Idaho Power's reason for including them is that it believes that because it would have been required to supply fuel for ongoing operations under any of the tolling agreements, it would logically have to also supply any fuel needed for start-up testing. I do not believe this would necessarily be the case, however.

Because no final tolling agreements were ever negotiated, we can only speculate about what the terms might have been. However, the draft tolling agreement included with the RFP and provided to all prospective bidders clearly indicates that bidders, not Idaho Power, would be responsible for the cost of start-up testing fuel. Section 6.5.3.5 of the draft tolling agreement states as follows: "Seller shall reimburse Idaho Power for supplying and delivering the Fuel required during Start-Up Testing to reach the minimum load of the Facility."

**This section of Staff's direct testimony contains confidential information subject to protective agreement.**

Q. What is your recommendation regarding transmission upgrades shown on line 45 of Exhibit No. 109?

A. I recommend that none of the costs of transmission upgrades be included in either the Soft Cap or the Hard Cap. I am not suggesting that upgrades are unnecessary or unwise, or that their cost should be unrecoverable. Instead, because these upgrades are not required as part of the Langley Gulch project, I am recommending that Idaho Power be required to demonstrate the prudence of the investments in a future general rate case just like it would other new investments in transmission.

Q. What is your recommendation regarding the 20 percent transmission contingency shown on line 46 of Exhibit No. 109?

A. The transmission study conducted by the Company's transmission group included a cost estimate believed accurate to within plus or minus 20 percent. The estimate transmission cost was used in preparing the Benchmark Resource proposal and was also used in comparing and scoring bids; however, Idaho Power recognizes that actual costs could exceed or be less than the estimate.

I agree that the transmission contingency might be incurred, but I do not agree that the contingency should be allowed as part of the pre-approved Commitment Estimate. Consequently, I recommend that the transmission contingency not be included in the Soft Cap, but included in the Hard Cap.

Q. What is your recommendation regarding the SSR ("sub-synchronous resonance") study shown on line 47 of Exhibit No. 109?

A. I recommend that 50 percent of the estimated cost be included in the Soft Cap and 150 percent be included in the Hard Cap. The Company seems to be quite uncertain about what the study may show, and the scope of possible remedies if SSR problems are identified in the study.

Q. What is your recommendation regarding the transmission costs shown on line 51 of Exhibit No. 109?

A. I recommend that 80 percent of the estimated costs be included in the Soft Cap and 120 percent be included in the Hard Cap. Idaho Power has stated that the transmission cost estimate has an accuracy of plus or minus 20 percent; therefore, actual costs could be as low as 80 percent of the estimate included in the Benchmark Resource bid or as high as 120 percent of the estimate. All other projects considered in the bid analysis included transmission cost estimates with the same degree of accuracy; consequently, I would have proposed the same treatment of transmission contingencies had one of them been the winning bidder.

Q. What is your recommendation regarding AFUDC costs shown on line 55 of Exhibit No. 109?

A. Details of Staff's recommendations are addressed in the testimony of Staff witness Harms. However, in summary, AFUDC will be accrued based on the actual amounts, timing, and borrowing rate for funds needed to construct the plant. Thus, the exact amount of AFUDC incurred can be computed and audited after the plant is completed. Therefore, Staff recommends that the actual amount of AFUDC incurred be recoverable, but that it be considered an addition to both the Soft Cap and the Hard Cap amounts.

Q. What are some of the factors you believe the Commission should consider when deciding whether to approve costs above the Commitment Estimate if the Commission decides that those costs should be subject to prudence review and Commission approval?

A. Some of the factors which I believe the Commission should consider are the following:

- the reasonableness of cost;
- the necessity of the expenditure;

- the consistency with project plans;
- the method of selection of contractors, materials, equipment, and vendors;
- whether the cost is based on competitive procurement of equipment, materials or services,
- the nature of expense;
- whether the work is completed on time;
- whether any costs are penalties or liquidated damages, and
- whether costs are consistent with pre-construction estimates.

I do not believe that any additional costs caused by Idaho Power's delay or negligence should be recoverable.

Q. Are there any additional costs that Idaho Power may incur because of its decision to delay the project's online date by six months?

A. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

On May 28, 2009, Idaho Power notified the Commission of changes to the Company's contract with Hoku Materials, Inc. One of the changes to the contract was a 40 MW required reduction in Hoku's summertime load in 2012. I cannot be certain whether Hoku voluntarily agreed to reduce its load during this period or whether Idaho Power required the reduction as a condition of Hoku delaying the start of its contract in the summer of 2009. Nevertheless, Idaho Power presumably would have been able to serve the load if Langley Gulch were available when originally scheduled. Now, with the delayed online date, Idaho Power will lose the revenue it would have otherwise received from Hoku. Depending on the cost Idaho Power would have incurred to serve Hoku during these months, Idaho Power could either make money or lose it due to Hoku's reduced load.

Q. Earlier you discussed the Commitment Estimate and all of the cost elements that compose it. Were all of the cost elements that are included in Idaho Power's proposed Commitment Estimate included in the Benchmark

Resource proposal that was scored by the Evaluation Team?
A. No, not all of the costs were included.
Q. Please describe how the Commitment Estimate is different than the Benchmark Resource proposal cost.
A. The Commitment Estimate includes several costs and contingencies that were added after the Benchmark Resource proposal was selected. Generally, those costs that were added are the items listed on lines 36-38 and lines 41-47 of Exhibit No. 108.
Q. Do you believe it was appropriate to add costs to the Commitment Estimate that were not included in the Benchmark Resource bid after the Benchmark Resource proposal was chosen as the winning bid?
A. In some cases it was appropriate because it was clear that some costs that were Idaho Power's responsibility would be added to every bid if chosen. However, in other cases, while I believe the costs are likely to be incurred, I think they should have been included in the Benchmark Resource proposal cost that was actually considered in scoring the proposals.
Q. Did Idaho Power reevaluate the costs of the top proposals and revise bid price scores based on the costs included in the Commitment Estimate?
A. Yes, in response to a production request, Idaho Power did compute revised price scores based on the

Commitment Estimate amount. The results of that re-scoring are shown on Exhibit No. 113. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

***Idaho Code* § 61-541**

Q. Idaho Power has requested approval of the proposed Langley Gulch project under *Idaho Code* § 61-541. Please discuss the requirements of this new legislation.

A. For reference purposes, I have included a copy of *Idaho Code* § 61-541 as Exhibit No. 115. *Idaho Code* § 61-541 provides that utilities may file an application with the Commission for an order specifying in advance the ratemaking treatments that shall apply when the costs of the proposed facility are included in the utility's revenue requirements. Among the ratemaking treatments the Commission may apply are to specify the maximum amount of costs that will be included in rates at the time without the utility having the burden of moving forward with additional evidence of the prudence and reasonableness of such costs. Effectively, this means that the Commission may pre-approve some portion of the project's expected costs.

Q. How would approval under *Idaho Code* § 61-541 differ from approval that has been given to prior new generation projects?

A. *Idaho Code* § 61-541 provides that all amounts approved under the legislation not be subject to further prudence review. This is really no different than the process recently used in approving Idaho Power's Evander Andrews/Danskin and Bennett Mountain plants because a CPCN for those plants was granted, along with a commitment estimate, prior to project construction. Any costs in excess of the commitment estimates approved in those cases were required to be submitted to the Commission for later approval.

Q. Do you believe Idaho Power has met the requirements of *Idaho Code* § 61-541 with its filing in this case?

A. *Idaho Code* § 61-541 requires the Commission in reviewing the application to determine whether:

(i) The public utility has in effect a commission-accepted integrated resource plan;

(ii) The services and operations resulting from the facility are in the public interest and will not be detrimental to the provision of adequate and reliable electric service;

(iii) The public utility has demonstrated that it has considered other sources for long-term electric supply or transmission;

(iv) The addition of the facility is reasonable when compared to energy efficiency, demand-side management and other feasible alternative sources of supply or transmission; and

(v) The public utility participates in a regional transmission planning process.

Assuming the Commission makes a ruling in this case addressing whether the proposed project is in the public interest, I believe all of these requirements will have been satisfied. Idaho Power does have an acknowledged integrated resource plan on file with the Commission. In the IRP, the utility considers other sources of supply, including transmission, energy efficiency and demand-side management. Idaho Power also participates in multiple regional transmission planning processes.

Q. If the Commission wishes to approve the Company's request to construct Langley Gulch, must it do so under *Idaho Code* § 61-541?

A. No, although Idaho Power has requested approval under *Idaho Code* § 61-541, the Commission may accept, deny of modify the proposed ratemaking treatment proposed by the utility. In addition, the Commission may determine the maximum amount of cost to be pre-approved for inclusion in rates without the utility having the burden of moving forward with additional evidence of the prudence and reasonableness of such costs. The Commission can require that amounts above the maximum be subject to the usual requirements of demonstration of prudence and reasonableness after the actual expenditures have been made and the utility seeks to recover them in rates.

Q. Do you believe preapproval of the Langley Gulch project is warranted in this case?

A. Because it is likely that preapproval is necessary in order for Idaho Power to obtain financing, I believe that those portions of the estimated project cost that are known with a high degree of certainty be preapproved under *Idaho Code* § 61-541. However, as I explained earlier, I believe that some portions of the project's estimated costs are not known with high enough certainty to merit preapproval. Regardless, issuance of CPCNs in the recent past have effectively provided preapproval anyway.

**TOTAL EXPECTED POWER COST**

Q. What is the total expected power cost for the proposed Langley Gulch plant?

A. **This section of Staff's direct testimony contains confidential information subject to protective agreement.**

It is also extremely important to recognize that the power cost 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 $9.39 per MMBtu in 2012, increasing to $15.55 per MMBtu in 2036. These estimates seem high based on recent gas prices and forecasts, but prices could turn out to be much different than assumed in the analysis or that are forecasted today. It should also be pointed out that the actual cost will ultimately also depend on the actual capacity factor. The actual capacity factor will vary from year to year and will be driven by loads, weather, and gas and electric market conditions. Higher capacity factors would lower the cost estimate while lower capacity factors would increase it. The cost estimate I have included here is only intended to be a rough indication of the total cost of energy produced by the plant.

Q. Are avoided cost rates for PURPA contracts a fair comparison to expected costs of the Langley Gulch plant?

A. I do not believe avoided cost rates used for PURPA QF contracts are a fair comparison to the cost Idaho Power will pay for power produced by the Langley Gulch plant. Although avoided cost rates are computed based on a surrogate combined cycle combustion turbine (SAR) very similar to Langley Gulch, assumptions about how the SAR and the Langley Gulch plant would be operated are much different. Avoided cost rate computations assume that the SAR plant is not economically dispatched and is instead operated at nearly its maximum achievable capacity factor. This is consistent with PURPA QFs that are not dispatchable and operate at as high a capacity factor as they can. The Langley Gulch plant clearly will be dispatchable, and will be operated only when it is cost effective to meet load or make surplus sales. Unlike the assumptions for the SAR or PURPA QFs, it will not be operated when it is not needed or when it is not profitable. Langley Gulch will almost certainly have a capacity factor less than the capacity factor assumed for the SAR. Consequently, there will be fewer hours over which to spread fixed costs, resulting in a higher cost per kWh than the PURPA avoided cost rate.

Q. How does the capital cost of the Langley Gulch project compare to other CCCT alternatives?

A. Based on the $427 million Commitment Estimate proposed by Idaho Power and Langley Gulch's 330 MW nameplate capacity, the capital cost is $1,294 per kW. By comparison, the current surrogate CCCT cost (which is based on current costs as reported by the Northwest Power and Conservation Council) used to establish the Idaho published avoided cost rate is $1,313/kW. Idaho Power's 2009 IRP proposes to use approximately $1,350 per kW for its assumption of new CCCT costs. PacifiCorp's just filed 2008 IRP shows new cost ranging from $1,180 to $1,491/kW for comparable plants, and Avista's nearly completed 2009 IRP shows new CCCT capital costs of approximately $1,050/kW. All cost listed here include an assumed amount for AFUDC. A 2008 RFP issued by PacifiCorp returned CCCT capital costs in the range of $1,000 to $1,300/kW.

Comparisons could also be made to recent transactions by Avista and PacifiCorp. In Avista's current general rate case, Avista is seeking approval of a tolling agreement for the Lancaster CCCT plant in Northern Idaho. Avista and its consultant separately performed net present value and DCF analysis to compare the Lancaster tolling agreement to other theoretical tolling agreements based on capital construction costs of existing regional CCCT resources. The analysis also compared the agreement to expected costs to construct a new CCCT in the region. The analyses show that the tolling agreement is essentially equivalent to a Company owned greenfield plant with a capital cost of about \$530/kW. Further analysis shows that the value of the tolling agreement is equivalent to paying up to \$677/kW. Another recent example of a comparable CCCT transaction was the purchase by PacifiCorp of the existing 500 MW Chehalis CCCT at a cost of approximately \$610/kW. It should be pointed out, however, that both the Lancaster plant and the Chehalis plants were built several years ago, so their costs may not be directly comparable to a new plant built today like Langley Gulch.

**FUEL COSTS**

Q. Idaho Power is requesting that the Project's prudently incurred costs for fuel, fuel storage, and fuel transportation for recovery through the Company's existing Power Cost Adjustment ("PCA") mechanism. Do you agree that this would be appropriate?

A. Yes, I do believe it would be appropriate to include these costs in the PCA until the Company's next general rate case when these costs can be normalized and included in base rates. Once these costs are included in base rates, only deviations from the normalized amounts of these costs would be included in the PCA, subject to the currently-approved 95-5 sharing percentages.

**STAFF CONCLUSIONS**

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

A. Yes, I am convinced that a new base load power plant is needed by Idaho Power beginning in 2012 and is in the public interest. The project is consistent with the Company's acknowledged IRPs. Under the right set of weather, load and hydro conditions, it could turn out that the plant may not actually be needed as soon as planned, but I believe it would be unacceptably risky to delay the plant. I do not believe Idaho Power could have pursued enough other alternatives that collectively could eliminate or be an acceptable substitute for the Langley Gulch plant.

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 for those proposals that were submitted. However, I think Idaho Power should have allowed build and transfer bids to be submitted.

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

A. Yes, with reservations. I recommend that the Commission approve a Commitment Estimate of $347.0 million plus actual AFUDC under *Idaho Code* § 61-541, and that any costs incurred above this commitment estimate be subject to review and approval by the Commission, with a "Not to Exceed limit" of $376.6 million plus actual AFUDC. If the Commission approves a Certificate of Convenience and Necessity for the project, I recommend that Idaho Power be ordered to provide the Commission with periodic progress reports during the construction phase. The progress reports should cover project costs, construction progress, permitting milestones, legal issues, problems encountered, or any other issues that should be brought to the attention of the Commission.

Q. Do you have any additional comments?

A. Yes, I would like to comment on the timing in this case. The need for a base load power plant has been a primary element in the Company's IRPs for many years. Even though the type of resource has changed since the need for new base load resource was first identified and it's exact timing has been a little uncertain, Idaho Power has had ample time to prepare for the addition of a new base load resource. Nevertheless, the Company in this case has stated that it did not have time to prepare detailed plans and specifications that would have been needed in order to accept build and transfer proposals. The Company has already signed agreements to purchase major equipment and has signed an EPC contract for work to commence in September, immediately following a Commission order in this case. Work must begin in September, according to the Company, in order to meet an online date of December 2012.

By filing its application when it did and by requiring such a tight schedule for initiation and project completion, Idaho Power has handcuffed the Commission in its decision making. Idaho Power's urgency has foreclosed the Commission from some decisions it might otherwise wish to make. There are few or no realistic alternatives that can be considered at this point that will not lead to higher costs. Unless the Commission approves the Company's requests in this case, any other decisions would likely cause additional costly delays. Staff does not believe that either ratepayers or the Commission should be held hostage because of the

Company's inability to plan and acquire resources in a less time constrained manner.

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

A. Yes, it does.

**Table 10. Updated Near-Term Action Plan through 2010**

**Activity**

***2008***

1. January - Issue RFP for 50-100 MW of geothermal energy.
2. March – 170 MW Danskin expansion on-line.
3. March – Prepare and submit the 2007 Demand-Side Management Annual Report.
4. April - Solicit expressions of interest from industrial customers for CHP development.
5. April - Issue 2012 Baseload Resource RFP.
6. June – Submit 2008 IRP Update to the Idaho and Oregon Commissions.
7. July – Begin the 2009 IRP process with the IRP Advisory Council.
8. September – Announce successful bidder(s) in the geothermal RFP process.
9. October – Bids due for the 2012 Baseload Resource RFP.

***2009***

1. Conclude the 2012 Baseload Resource RFP process.
2. Continue DSM implementation plans with guidance from the EEAG.
3. Continue working with industrial customers on CHP development opportunities.
4. Complete the 2009 IRP and submit to the Idaho and Oregon Commissions in June 2009.
5. Make final commitments on 225 MW Hemingway-Boardman Transmission Project.
6. Make final commitments on 500 kV Gateway West Transmission Project.
7. Activities associated with the 2012 Baseload Resource RFP depending on the outcome of the RFP process.

***2010***

1. Continue DSM implementation plans with guidance from the EEAG.
2. Issue RFP for wind generation depending on current level of PURPA wind development.

**Table 11. 2006 IRP Preferred Portfolio and Updated Portfolio**

| **2006 IRP Preferred Portfolio** | | | **Updated Portfolio** | | |
|---|---|---|---|---|---|
| **Year** | **Resource** | **MW** | **Year** | **Resource** | **MW** |
| 2008 | Wind (2005 RFP) | 100 | 2008 | Wind (2005 RFP)[1] | 100 |
| 2009 | Geothermal (2006 RFP) | 50 | 2009 | Geothermal (2006 RFP)[2] | 50 |
| 2010 | CHP | 50 | 2010 | CHP (2008 Solicitation)[3] | 50 |
| | | | 2011 | Geothermal (2008 RFP)[4] | 50 |
| 2012 | Wind | 150 | 2012 | Wind[5] | 150 |
| 2012 | Transmission McNary–Boise | 225 | 2012 | Trans. Hemingway-Boardman[6] | 225 |
| | | | 2012 | Southwest Idaho CCCT[7] | 250 |
| 2013 | Wyoming Pulverized Coal[7] | 250 | | | |
| 2017 | Regional IGCC Coal | 250 | 2017 | Regional IGCC Coal | 250 |
| 2019 | Transmission Lolo–IPC | 60 | 2019 | Transmission Lolo–IPC | 60 |
| 2020 | CHP | 100 | 2020 | CHP | 100 |
| 2021 | Geothermal | 50 | 2021 | Geothermal | 50 |
| 2022 | Geothermal | 50 | 2022 | Geothermal | 50 |
| 2023 | INL Nuclear | 250 | 2023 | INL Nuclear | 250 |
| | **Total Nameplate** | **1,585** | | **Total Nameplate** | **1,635** |

1 Horizon Wind Energy Contract (100.65 MW) - Elkhorn Valley Wind Project (on-line December 2007).

2 U.S. Geothermal Contract (45.5 MW) - Raft River #1 (13 MW on-line October 2007), Raft River #3 (6.5 MW) and Neal Hot Springs #1 (13 MW) and #2 (13 MW) are under development.

3 In April 2008, Idaho Power began soliciting industrial customers within its service area for expressions of interest in the development of combined heat and power projects at existing industrial facilities. Depending on the level of interest, a formal RFP may be issued in late 2008.

4 An RFP for 50 to 100 MW of geothermal energy was released in January 2008 to offset deficits resulting from PURPA contract terminations.

5 Actual quantity will depend on level of PURPA wind development.

6 Project was renamed once actual termination points were identified.

7 Due to escalating construction costs and continued uncertainty surrounding future GHG laws and regulations, Idaho Power has shifted its focus from a conventional coal-fired resource to the development of a combined-cycle, natural gas resource located closer to its load center in southern Idaho.

Exhibit No. 101
Case No. IPC-E-09-3
R. Sterling, Staff
06/19/09

## 2006 IRP Average Energy Load and Generation (70th% Water, 70th% Load)

Mar-08

| Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2006 IRP Load Forecast | (2,367) | (2,412) | (2,459) | (2,494) | (2,529) | (2,577) | (2,624) | (2,676) | (2,728) | (2,781) | (2,836) | (2,892) | (2,949) | (3,007) | (3,068) | (3,129) | (3,191) | (3,254) | (3,324) | (3,393) |
| Coal | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 | 895 |
| Hydro (70th%) - HCC | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 | 563 |
| Hydro (70th%) - ROR | 325 | 325 | 325 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 | 340 |
| CSPP (including wind) | 186 | 186 | 180 | 177 | 177 | 178 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 |
| PURPA Wind Capacity | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL MT | 45 | 45 | 46 | 43 | 43 | 45 | 45 | 45 | 43 | 43 | 43 | 45 | 45 | 46 | 43 | 43 | 45 | 45 | 44 | 44 |
| Existing Imports | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas Peakers | 353 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 | 383 |
| **Subtotal** | **0** | **(15)** | **(67)** | **(93)** | **(128)** | **(173)** | **(229)** | **(281)** | **(335)** | **(389)** | **(443)** | **(497)** | **(554)** | **(612)** | **(675)** | **(736)** | **(796)** | **(859)** | **(931)** | **(999)** |
| 2008 Wind - Elkhorn | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| 2009 Geothermal - US Geo | 0 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| 2010 CHP | 0 | 0 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| 2012 IRP Wind | 0 | 0 | | | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 |
| 2012 McNary - Boise | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2013 Coal | 0 | 0 | 0 | 0 | 0 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 |
| 2017 IGCC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| 2019 Lolo - IPCo | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2020 CHP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| 2022 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 48 | 48 | 48 | 48 | 48 |
| 2023 INL Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 225 | 225 | 225 | 225 | 225 |
| DSM | 6 | 15 | 25 | 35 | 43 | 50 | 56 | 61 | 66 | 69 | 71 | 74 | 76 | 78 | 81 | 83 | 85 | 88 | 88 | 88 |
| **Subtotal** | **37** | **94** | **149** | **159** | **214** | **441** | **447** | **452** | **457** | **660** | **662** | **665** | **757** | **807** | **858** | **1,085** | **1,087** | **1,090** | **1,090** | **1,090** |
| **2006 IRP Energy Surplus/Deficits** | **37** | **79** | **82** | **66** | **86** | **268** | **218** | **171** | **122** | **271** | **219** | **168** | **203** | **195** | **183** | **349** | **291** | **231** | **159** | **91** |
| **2006 IRP Modifications** | | | | | | | | | | | | | | | | | | | | |
| Shoshone Falls | 0 | 0 | 0 | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) |
| Fish Water | (112) | (114) | (115) | (116) | (118) | (119) | (121) | (122) | (124) | (125) | (127) | (127) | (127) | (127) | (127) | (127) | (127) | (127) | (127) | (127) |
| PURPA Wind Capacity Cor. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CSPP Updates | (46) | (44) | (38) | (2) | (2) | (10) | (2) | (2) | (7) | (24) | (29) | (32) | (42) | (45) | (47) | (57) | (74) | (74) | (76) | (78) |
| US Geothermal Timing | 13 | (24) | (24) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Lucky Peak Exchange | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| New Geothermal (Jan 2012) | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Remove 2010 IRP CHP | 0 | 0 | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) |
| Remove 2012 IRP Wind | 0 | 0 | 0 | 0 | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) | (47) |
| Remove 2013 IRP Coal | 0 | 0 | 0 | 0 | 0 | (220) | (220) | (220) | (220) | (220) | (220) | (220) | (220) | (220) | (220) | (220) | (220) | (220) | (220) | (220) |
| Remove 2017 IRP IGCC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) |
| New Gas-Fired CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Remove IRP DSM | (6) | (15) | (25) | (35) | (43) | (50) | (56) | (61) | (66) | (69) | (71) | (74) | (76) | (78) | (81) | (83) | (85) | (88) | (88) | (88) |
| **Total** | **(151)** | **(196)** | **(252)** | **(219)** | **(225)** | **(462)** | **(461)** | **(468)** | **(478)** | **(701)** | **(709)** | **(715)** | **(727)** | **(732)** | **(737)** | **(749)** | **(768)** | **(771)** | **(773)** | **(775)** |
| **Load Forecast Change** | **32** | **(1)** | **9** | **8** | **25** | **44** | **74** | **99** | **111** | **142** | **172** | **187** | **199** | **211** | **223** | **236** | **250** | **262** | **276** | **287** |
| **Year** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** |
| **Updated Energy Surplus/Deficits** | **(82)** | **(119)** | **(161)** | **(144)** | **(114)** | **(150)** | **(170)** | **(198)** | **(246)** | **(287)** | **(318)** | **(360)** | **(325)** | **(326)** | **(331)** | **(164)** | **(227)** | **(278)** | **(338)** | **(397)** |

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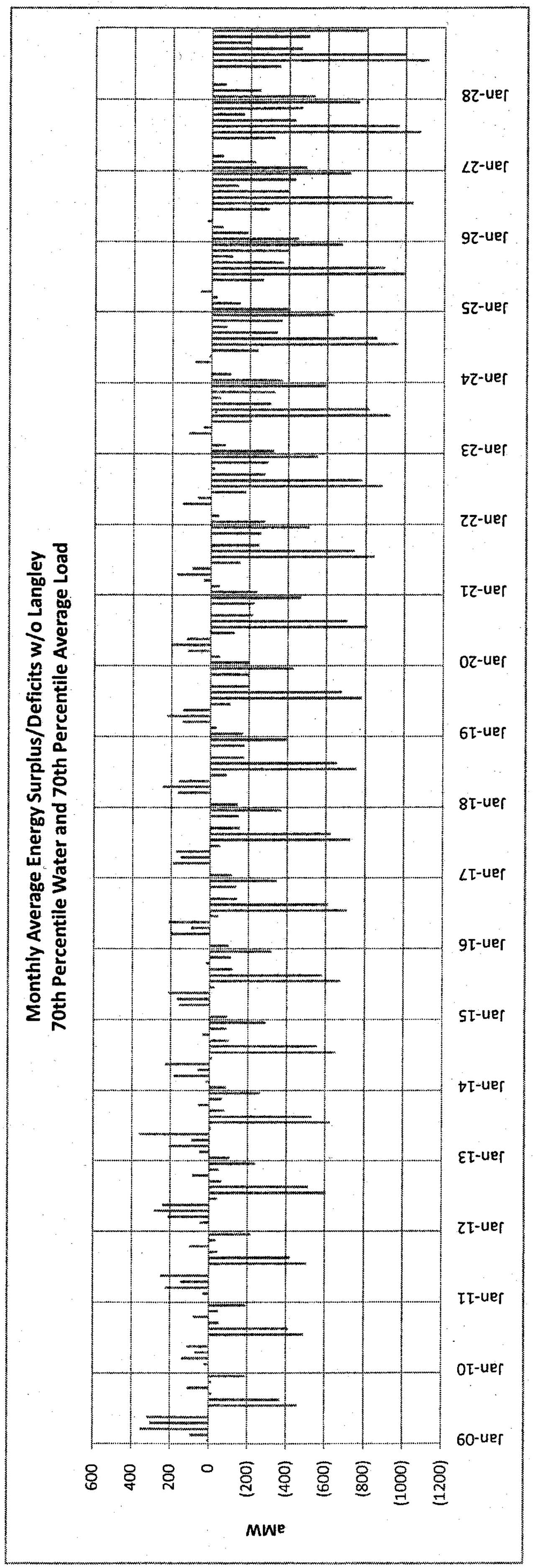
## 2006 IRP Peak-Hour Load and Generation (90th% Water, 95th% Load)

Mar-08

| Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2006 IRP Load Forecast | (3,312) | (3,372) | (3,442) | (3,506) | (3,570) | (3,647) | (3,723) | (3,805) | (3,888) | (3,972) | (4,058) | (4,144) | (4,231) | (4,321) | (4,411) | (4,503) | (4,595) | (4,689) | (4,783) | (4,880) |
| Coal | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 | 973 |
| Hydro (90th%) - HCC | 1,049 | 1,055 | 1,045 | 1,039 | 1,025 | 1,009 | 1,003 | 1,013 | 1,005 | 1,000 | 988 | 978 | 965 | 978 | 973 | 968 | 946 | 945 | 943 | 941 |
| Hydro (90th%) - ROR | 309 | 309 | 309 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 | 323 |
| CSPP (including wind) | 160 | 159 | 153 | 150 | 150 | 150 | 142 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 |
| PURPA Wind Capacity | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| PPL MT | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Existing Imports | 340 | 326 | 272 | 328 | 257 | 344 | 342 | 322 | 319 | 314 | 195 | 316 | 318 | 161 | 285 | 138 | 127 | 279 | 250 | 250 |
| Gas Peakers | 387 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **(1)** | **(40)** | **(181)** | **(183)** | **(332)** | **(338)** | **(430)** | **(523)** | **(616)** | **(711)** | **(928)** | **(903)** | **(1,001)** | **(1,235)** | **(1,206)** | **(1,449)** | **(1,575)** | **(1,518)** | **(1,643)** | **(1,742)** |
| 2008 Wind - Elkhorn | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 2009 Geothermal - US Geo | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| 2010 CHP | 0 | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| 2012 IRP Wind | 0 | 0 | 0 | 0 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 2012 McNary - Boise | 0 | 0 | 0 | 0 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 |
| 2013 Coal | 0 | 0 | 0 | 0 | 0 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2017 IGCC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2019 Lolo - IPCo | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2020 CHP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| 2022 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 50 | 50 | 50 |
| 2023 INL Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 250 | 250 | 250 | 250 | 250 |
| DSM | 16 | 45 | 71 | 92 | 110 | 127 | 141 | 152 | 163 | 165 | 168 | 171 | 174 | 176 | 179 | 182 | 185 | 187 | 187 | 187 |
| **Subtotal** | **21** | **100** | **176** | **197** | **448** | **715** | **729** | **740** | **751** | **1,003** | **1,006** | **1,009** | **1,112** | **1,164** | **1,217** | **1,470** | **1,473** | **1,475** | **1,475** | **1,475** |
| **2006 IRP Peak Surplus/Deficits** | **20** | **60** | **(5)** | **14** | **116** | **377** | **299** | **217** | **134** | **292** | **78** | **106** | **111** | **(71)** | **12** | **21** | **(102)** | **(43)** | **(168)** | **(267)** |
| **2006 IRP Modifications** | | | | | | | | | | | | | | | | | | | | |
| Shoshone Falls | 0 | 0 | 0 | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) |
| Fish Water | (56) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) | (58) |
| PURPA Wind Capacity Cor. | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | (14) |
| CSPP Updates | (46) | (44) | (43) | (36) | (36) | (44) | (36) | (36) | (40) | (58) | (62) | (66) | (76) | (79) | (80) | (91) | (108) | (108) | (108) | (110) |
| US Geothermal Timing | 13 | (24) | (24) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Lucky Peak Exchange | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| New Geothermal | 0 | 0 | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| CHP | 0 | 0 | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) | (50) |
| 2012 IRP Wind | 0 | 0 | 0 | 0 | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) |
| Remove 2013 Coal | 0 | 0 | 0 | 0 | 0 | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) |
| Remove 2017 IGCC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) | (250) |
| New Gas-Fired CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Remove IRP DSM | (16) | (45) | (71) | (92) | (110) | (127) | (141) | (152) | (163) | (165) | (168) | (171) | (174) | (176) | (179) | (182) | (185) | (187) | (187) | (187) |
| **Total** | **(118)** | **(185)** | **(259)** | **(214)** | **(241)** | **(515)** | **(521)** | **(533)** | **(547)** | **(818)** | **(824)** | **(831)** | **(844)** | **(850)** | **(854)** | **(868)** | **(887)** | **(890)** | **(890)** | **(892)** |
| **Load Forecast Change** | 28 | (11) | (4) | (5) | 12 | 30 | 57 | 82 | 95 | 126 | 157 | 172 | 184 | 197 | 209 | 223 | 236 | 249 | 256 | 265 |

| Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Updated Peak Surplus/Deficits | (70) | (136) | (268) | (205) | (113) | (108) | (165) | (234) | (318) | (400) | (590) | (554) | (550) | (724) | (633) | (624) | (754) | (684) | (802) | (894) |

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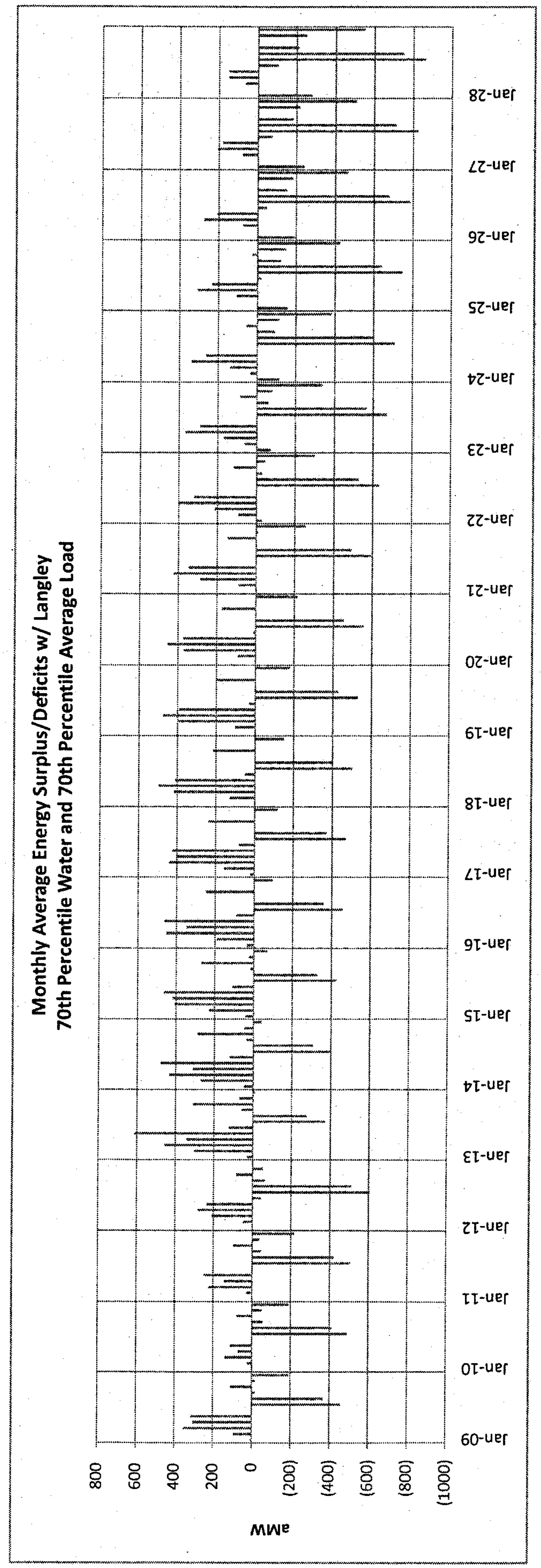
Monthly Average Energy Surplus/Deficits w/ Langley
70th Percentile Water and 70th Percentile Average Load
aMW
800
600
400
200
0
(200)
(400)
(600)
(800)
(1000)
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20
Jan-21
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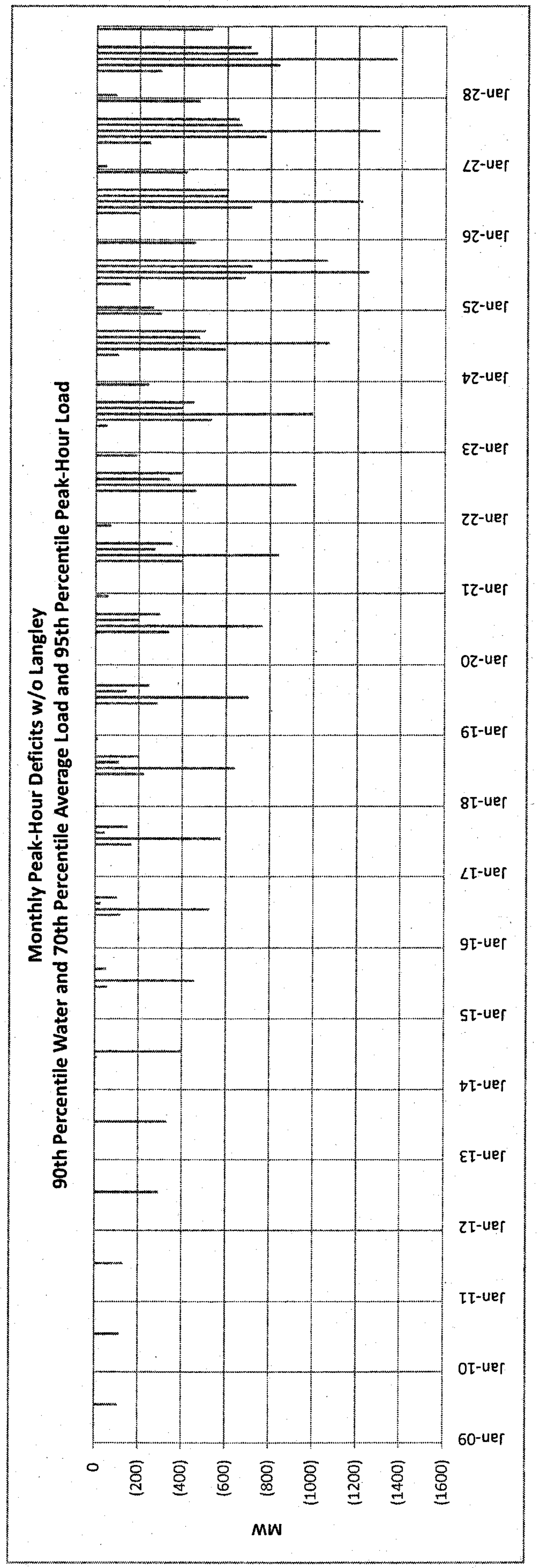
Jan-23
Jan-24
Jan-25
Jan-26
Jan-27
Jan-28

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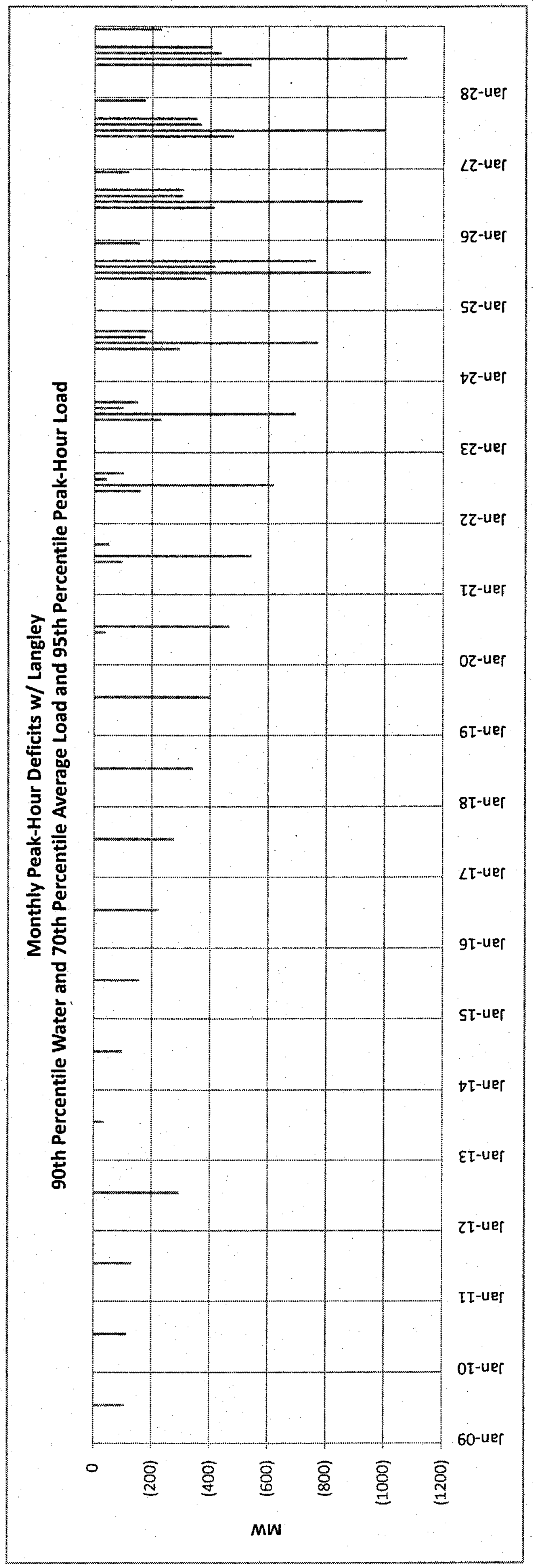


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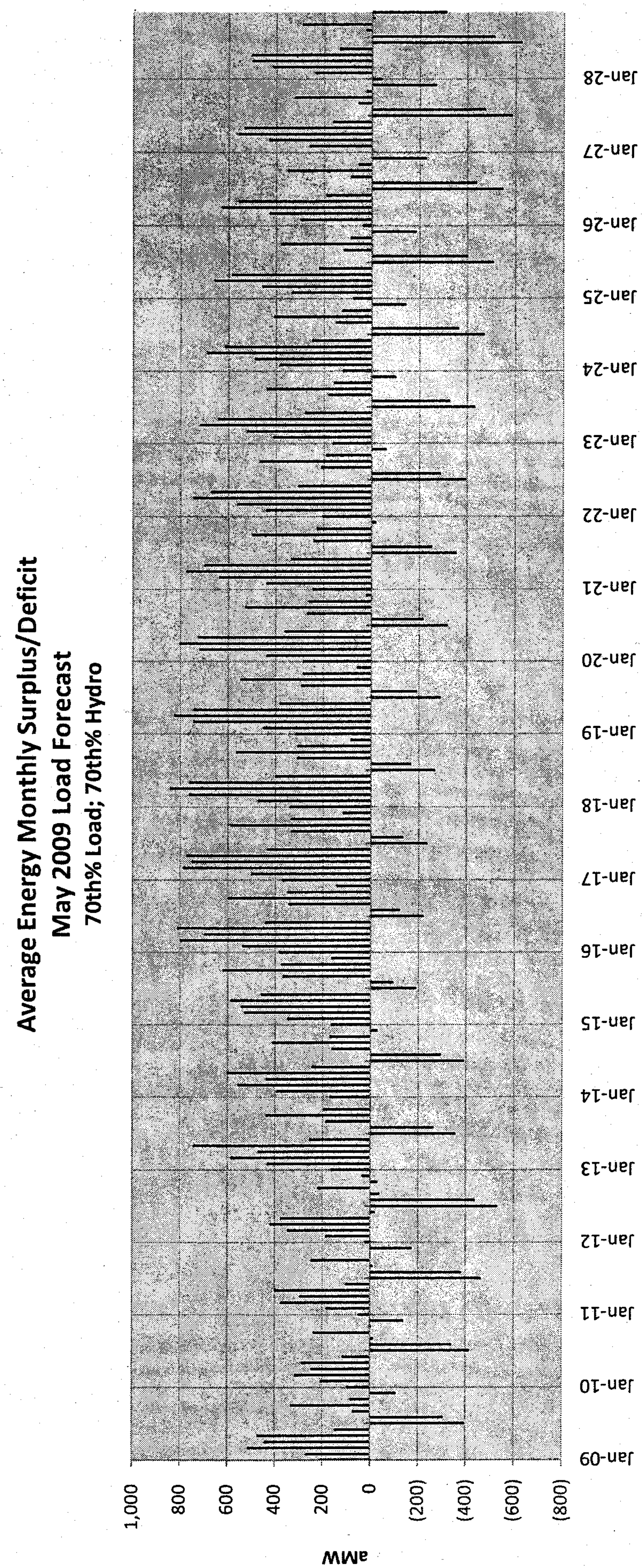


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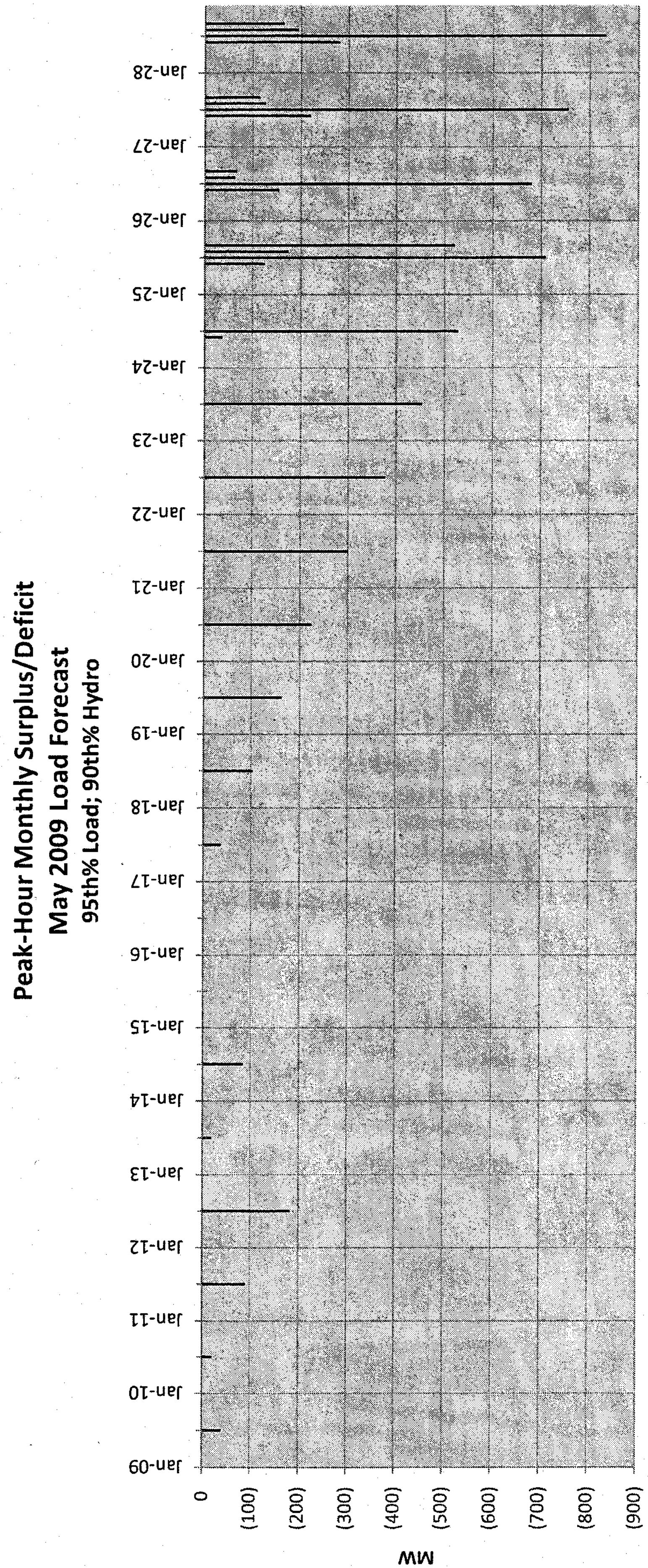


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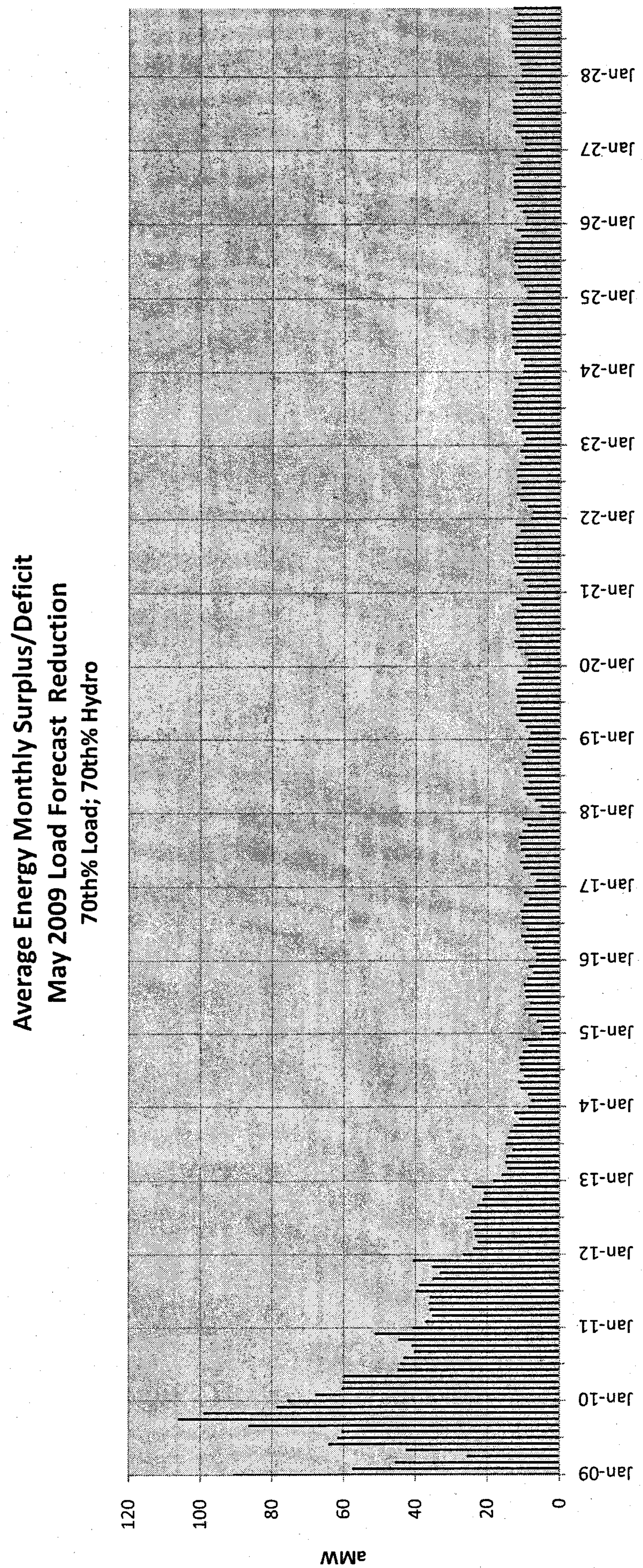


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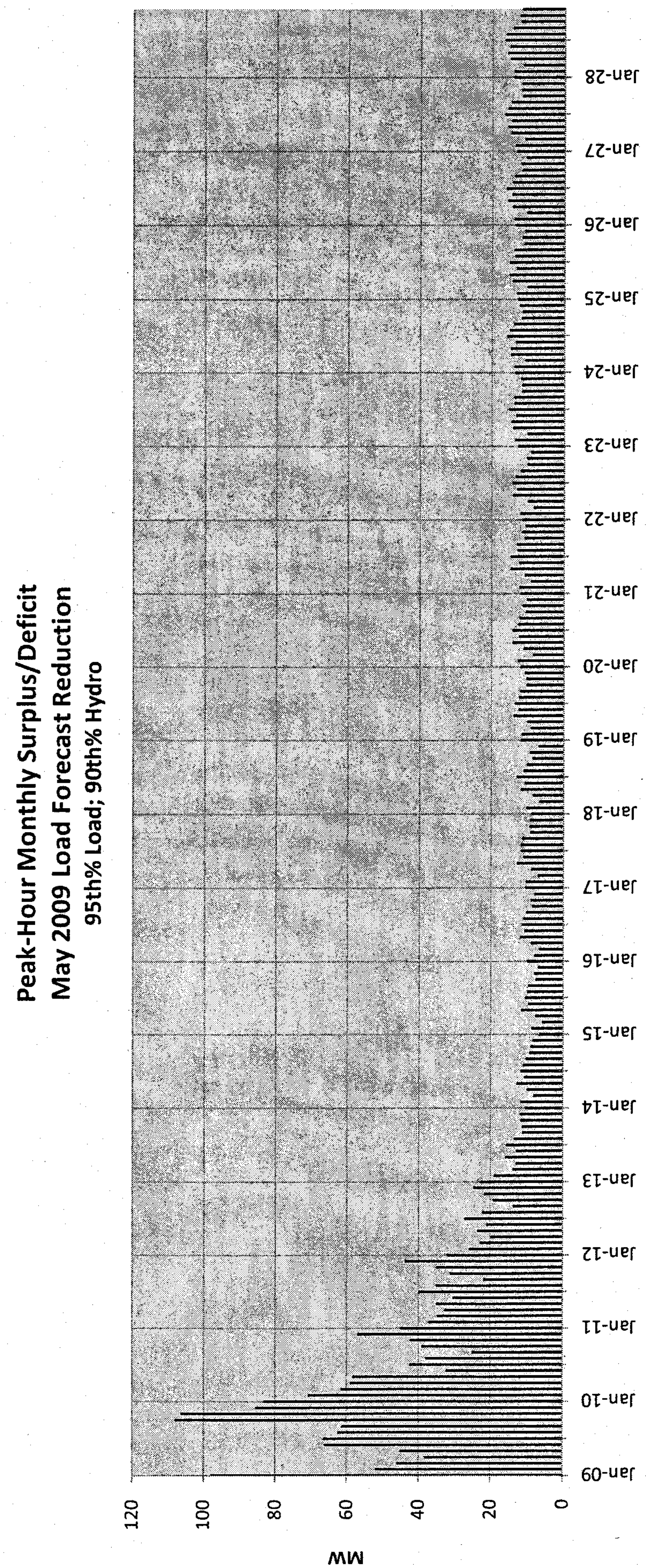


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## 9.0 Criteria Used for Scoring Qualified Proposals

This section briefly describes the criteria Idaho Power will use to evaluate proposals submitted in response to the RFP. The following tables summarize these criteria. For a more detailed description of information that should accompany each proposal, see Attachment G, "Required Proposal Information".

**Table 1. Evaluation Criteria**

| Factors | Descriptions | Subtotal | Total |
|---|---|---|---|
| Price | Price - This category captures all fixed and variable costs of the capacity and energy delivered under the proposal. This evaluation will include the nominal and present worth costs of delivered power. | | 60% |
| Non-Price | | | 40% |
| A | Project Development: This category captures the Respondents general background, financing capability and ability to get the project completed on time.<br>1. Permitting status<br>2. Developer experience<br>3. Project financing<br>4. Site Control | 8% | |
| B | Project Characteristics: This category captures the physical characteristics of any generation resource necessary to support Respondent's proposal. The evaluation criteria for this category generally addresses physical and operational characteristics associated with the production and delivery of power to Idaho Power.<br>1. Point-of-Delivery[3]<br>2. Resource base of energy project<br>3. O&M reliability characteristics<br>4. Extension option<br>5. Option to purchase after initial term<br>6. Impact on most severe single contingency | 8% | |
| C | Product Characteristics: This category scores how well the proposed product matches Idaho Power's operational needs. The evaluation criteria for this category generally address price and performance along with the benefits of flexibility and optionality.<br>1. Guaranteed Availability Factor (GAF)<br>2. Compensation for failure to meet GAF<br>3. Flexibility, dispatch and load following capability<br>4. Contract term<br>5. Seasonal de-rating<br>6. Operational limitations | 8% | |
| D | Project Location: This category captures the siting characteristics of any generation resource(s) necessary to support Respondent proposed projects. Specifically: with EPA's recent announcement to change the ozone standard and the likelihood of Ada County being listed as a non-attainment area, the Company is concerned about potential future operating restrictions being placed on any projects located in the Treasure Valley. Idaho Power's evaluation will strictly scrutinize proposals that are supplied or supported by generation resources planned to be built in Ada or Canyon counties; It will also consider whether community opposition to a plant will delay the completion of necessary facilities. | 8% | |
| E | Environmental: This category captures the environmental impacts of proposals, including CO2 emissions.<br>1. Land use<br>2. Water use and discharge<br>3. Fish and wildlife<br>4. Noise output<br>5. Emissions | 3% | |
| F | Credit Factors and Financial Strength: This category captures the creditworthiness and strength of the Respondent's financial sustainability. | 5% | |
| Total: | | | 100% |

[3] Please refer to Section 11.0 Transmission Interconnection



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**Case No. IPC-E-09-3**

**Exhibit No. 107 prepared and sponsored by Rick Sterling is Confidential and only available to those persons who have signed Protective Agreements**

# Case No. IPC-E-09-3

**Exhibit No. 108 prepared and sponsored by Rick Sterling is Confidential and only available to those persons who have signed Protective Agreements**

Case No. IPC-E-09-3

Exhibit No. 109 prepared and sponsored by Rick Sterling is Confidential and only available to those persons who have signed Protective Agreements

**Case No. IPC-E-09-3**

**Exhibit No. 110 prepared and sponsored by Rick Sterling is Confidential and only available to those persons who have signed Protective Agreements**

# Case No. IPC-E-09-3

## Exhibit No. 111 prepared and sponsored by Rick Sterling is Confidential and only available to those persons who have signed Protective Agreements

# Case No. IPC-E-09-3

**Exhibit No. 112 prepared and sponsored by Rick Sterling is Confidential and only available to those persons who have signed Protective Agreements**

Case No. IPC-E-09-3

Exhibit No. 113 prepared and sponsored by Rick Sterling is Confidential and only available to those persons who have signed Protective Agreements

**Case No. IPC-E-09-3**

**Exhibit No. 114 prepared and sponsored by Rick Sterling is Confidential and only available to those persons who have signed Protective Agreements**

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2009 JUL 10 AM 11:23

IDAHO PUBLIC
UTILITIES COMMISSION

To: Parties of Record
Commission Secretary

From: Commission Staff

Date: July 10, 2009

RE: Case No. IPC-E-09-03

Attached please find Exhibit No. 115 to the Direct Testimony of Staff witness Rick Sterling previously filed on June 19, 2009. Exhibit No. 115 was erroneously labeled as a confidential exhibit.

Substitute pages will be provided at the hearing on July 14, 2009.

Please contact me if you have any questions at (208) 334-0320.

LEGISLATURE OF THE STATE OF IDAHO

Sixtieth Legislature First Regular Session - 2009

IN THE SENATE

SENATE BILL NO. 1123

BY STATE AFFAIRS COMMITTEE

AN ACT

RELATING TO PUBLIC UTILITY RATES; AMENDING CHAPTER 5, TITLE 61, IDAHO CODE, BY THE ADDITION OF A NEW SECTION 61-541, IDAHO CODE, TO DEFINE A TERM, TO PROVIDE THAT PUBLIC UTILITY COMMISSION BINDING RATEMAKING TREATMENTS ARE APPLICABLE WHEN COSTS OF A NEW ELECTRIC GENERATION FACILITY ARE INCLUDED IN RATES, TO PROVIDE PROCEDURES AND TO PROVIDE FOR RULES.

Be It Enacted by the Legislature of the State of Idaho:

SECTION 1. That Chapter 5, Title 61, Idaho Code, be, and the same is hereby amended by the addition thereto of a NEW SECTION, to be known and designated as Section 61-541, Idaho Code, and to read as follows:

61-541. BINDING RATEMAKING TREATMENTS APPLICABLE WHEN COSTS OF A NEW ELECTRIC GENERATION FACILITY ARE INCLUDED IN RATES. (1) As used in this section, "certificate" means a certificate of convenience and necessity issued under section 61-526, Idaho Code.

(2) A public utility that proposes to construct, lease or purchase an electric generation facility or transmission facility, or make major additions to an electric generation or transmission facility, may file an application with the commission for an order specifying in advance the ratemaking treatments that shall apply when the costs of the proposed facility are included in the public utility's revenue requirements for ratemaking purposes. For purposes of this section, the requested ratemaking treatments may include nontraditional ratemaking treatments or nontraditional cost recovery mechanisms.

(a) In its application for an order under this section, a public utility shall describe the need for the proposed facility, how the public utility addresses the risks associated with the proposed facility, the proposed date of the lease or purchase or commencement of construction, the public utility's proposal for cost recovery, and any proposed ratemaking treatments to be applied to the proposed facility.

(b) For purposes of this section, ratemaking treatments for a proposed facility include but are not limited to:

(i) The return on common equity investment or method of determining the return on common equity investment;

(ii) The depreciation life or schedule;

(iii) The maximum amount of costs that the commission will include in rates at the time determined by the commission without the public utility having the burden of moving forward with additional evidence of the prudence and reasonableness of such costs;

(iv) The method of handling any variances between cost estimates and actual costs; and

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R. Sterling, Staff
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(v) The treatment of revenues received from wholesale purchasers of service from the proposed facility.

(3) The commission shall hold a public hearing on the application submitted by the public utility under this section. The commission may hold its hearing in conjunction with an application for a certificate.

(4) Based upon the hearing record, the commission shall issue an order that addresses the proposed ratemaking treatments. The commission may accept, deny or modify a proposed ratemaking treatment requested by the utility. In determining the proposed ratemaking treatments, the commission shall maintain a fair, just and reasonable balance of interests between the requesting utility and the utility's ratepayers.

(a) In reviewing the application, the commission shall also determine whether:

(i) The public utility has in effect a commission-accepted integrated resource plan;

(ii) The services and operations resulting from the facility are in the public interest and will not be detrimental to the provision of adequate and reliable electric service;

(iii) The public utility has demonstrated that it has considered other sources for long-term electric supply or transmission;

(iv) The addition of the facility is reasonable when compared to energy efficiency, demand-side management and other feasible alternative sources of supply or transmission; and

(v) The public utility participates in a regional transmission planning process.

(b) The commission shall use its best efforts to issue the order setting forth the applicable ratemaking treatments prior to the date of the proposed lease, acquisition or commencement of construction of the facility.

(c) The ratemaking treatments specified in the order issued under this section shall be binding in any subsequent commission proceedings regarding the proposed facility that is the subject of the order, except as may otherwise be established by law.

(5) The commission may not require a public utility to apply for an order under this section.

(6) The commission may promulgate rules or issue procedural orders for the purpose of administering this section.

# CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 10TH DAY OF JULY 2009, SERVED THE FOREGOING **NON-CONFIDENTIAL EXHIBIT NO. 115 OF RICK STERLING'S DIRECT TESTIMONY,** IN CASE NO. IPC-E-09-03, BY ELECTRONIC MAIL AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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Jo Nelson
SECRETARY

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 19TH DAY OF JUNE 2009, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING,** IN CASE NO. IPC-E-09-3, BY ELECTRONIC MAIL AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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