STATE OF IDAHO

OFFICE OF THE ATTORNEY GENERAL

LAWRENCE G. WASDEN

HAND DELIVERED

December 15, 2003

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington Street
Boise, ID 83720-0074

RE: Staff Comments in Case No. IPC-E-03-12

Dear Secretary:

Enclosed with this transmittal letter are the Staff Comments in the above referenced case. Attachment 7 to the Staff Comments contains trade secret or confidential material exempt from public inspection, examination or copying per *Idaho Code* § 9-340D(1). Accordingly, Confidential Attachment 7 is separately submitted under seal pursuant to Rule 67, IDAPA 31.01.01.067.

I appreciate your assistance in this matter.

Sincerely,

Donald L. Howell, II
Deputy Attorney General

Enclosure

cc: Parties of Record

bls/L:IPCE0312_dh

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE RATEBASING OF THE BENNETT MOUNTAIN POWER PLANT.	)	**CASE NO. IPC-E-03-12** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Donald L. Howell, II, Deputy Attorney General, and submits the following comments in response to Order No. 29370 issued on October 30, 2003.

On September 26, 2003, Idaho Power Company filed an Application for a Certificate of Public Convenience and Necessity to construct a new generating plant in Mountain Home, Idaho. *Idaho Code* §61-526 prohibits any electrical corporation from constructing a generating plant "without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction." Idaho Power requested that the Commission issue an Order granting a Certificate of Public Convenience and Necessity to construct the project and authorize the ratebasing of plant costs up to the "Commitment Estimate" of $54.0 million (excluding transmission). Idaho Power also requested

that the Order confirm that the fuel costs for the project, if approved, will be included in the Company's annual Power Cost Adjustment (PCA) proceeding.

BACKGROUND

Idaho Power maintains that its decision to construct the new generating plant is based on its 2002 integrated resource plan (IRP). The IRP process evaluated Company future loads and resources and evaluated various options for meeting projected loads. The options for meeting load include: the purchase of power from the wholesale market; the acquisition of additional generating resources; the implementation of pricing options; and/or implementing demand-side management programs. In short, the IRP is a planning process on how the Company intends to meet its statutory obligations to serve its customers' loads.

Idaho Power's strategy for meeting future load was described in the 2002 IRP as follows:

1) continue to make seasonal market purchases of 100 average megawatts (aMW) in the months of June, July, November and December throughout the ten-year planning period;
2) integrate demand side measures where economical to address the short duration peaks of system load;
3) issue a Request for Proposal (RFP) for approximately 100 MW of a utility-owned and operated peaking resource to be available in 2005;
4) upgrade the Brownlee to Oxbow transmission line to be in service in 2005, thus increasing the import capabilities from the Northwest;
5) upgrade the Shoshone Falls plant to increase its capacity by 64 MW; and
6) purchase up to 250 MW of capacity and associated energy from the Garnet plant beginning in June 2005.

Case No. IPC-E-02-8.

As set out above, the Company's 2002 IRP included an assumption that Idaho Power would purchase up to 250 MW of capacity from the proposed Garnet plant that was to be constructed in Middleton, Idaho. The Garnet capacity was intended to meet the summer peaks beginning in June 2005. In October 2002, the Company reported that the Garnet project was being abandoned because Garnet was unable to secure the necessary financing.

The 2002 IRP was modified as a result of Garnet's inability to acquire financing. At the request of the Commission, Idaho Power supplemented its 2002 IRP with the "Garnet Report" in October 2002. In the Garnet Report, the Company identified alternatives to the Garnet project including potential purchases from the east side of its system. The Garnet Report also stated that the Company was seriously considering increasing the planned 2003 RFP from 100 MW to approximately 170 MW. The Commission acknowledged the 2002 IRP as supplemented with the Garnet Report in February 2003.

Idaho Power has been able to acquire at least one of the alternatives to Garnet as discussed in the 2002 Garnet Report. On July 8, 2003, the Commission approved a Power Purchase Agreement between Idaho Power and PPL Montana, LLC. Order No. 29286. The PPL Montana agreement will provide 83 MW of firm power during heavy load hours, six days a week, 16 hours per day in the months of June, July and August beginning in June 2004. Adjusting for losses, the 83 MW purchase replaces approximately 80 MW of the Garnet project, which was anticipated to provide up to 250 MW during the same summer season peak hours. The Bennett Mountain plant (162 MW) is also intended to replace, in part, the loss of the Garnet capacity.

STAFF ANALYSIS

IRP Planning

Idaho Power issued its "Garnet RFP" based on conclusions it reached after completion of the 2000 IRP. In early 2000, during the time Idaho Power was preparing the 2000 IRP, market prices were much higher than previous years due in part to poor water conditions. Idaho Power recognized that poor water conditions increased its reliance on the market and that such a heavy reliance on the market presented greater risk if market prices were to rise even further. Very shortly after the IRP was filed with the Commission in July 2000, market prices began to skyrocket, eventually reaching unprecedented levels. Idaho Power began searching for lower cost alternative sources of power. In early 2001, Idaho Power decided to build the 90 MW simple-cycle gas-fired Danskin plant at Mountain Home. The plant eventually went on-line in September 2001. In addition, the Company implemented several load reduction programs including the irrigation buy-back program, and leased several mobile diesel generators.

The extreme run up in prices during 2000-2001 affected Idaho Power's IRP planning. The extremely high market prices and poor water conditions caused Idaho Power to incur huge purchased power costs that ultimately had to be passed through the PCA. That, in turn, led to the highest rates in Idaho Power's history. In response, the Company developed a new risk management policy and, for the 2002 IRP, changed the water condition upon which it plans from a "median" water condition to a 70th percentile water condition. The 70th percentile water condition means that Idaho Power plans generation based on stream flows that occur in seven out of 10 years on average. Stream flow conditions are expected to be worse than the planning criteria 30 percent of the time. A 70th percentile monthly water planning criteria differentiates Idaho Power from other northwest utilities that typically plan resources based on having annual generating capability sufficient to meet forecast annual energy requirements under "critical" water conditions. Critical water conditions are generally defined to be the worst, or nearly the worst, annual water conditions based on historical stream flow records. The 90th percentile water condition is also now examined for planning purposes. In addition, the Company now plans for 70th percentile load conditions that can result from periods of severe hot or cold weather.

Staff believes that the Company's decision to begin planning based on the 70th percentile water conditions and 70th percentile weather related load conditions is appropriate. Planning based on median water conditions was more acceptable in the past when the western power market could be relied on for an adequate supply of predictably priced power. Now, however, Idaho Power has identified transmission constraints that limit the availability of power from the market during certain times of the year. In addition, even though market prices have dropped from 2000-2001 highs, prices are much more volatile than in the past. Even if the market could be relied on when conditions differ from median, the price volatility and its effect on retail rates can be problematic for customers. Staff believes that it is prudent for Idaho Power to employ more conservative planning criteria than in the past.

On an annual basis, median water generation capability exceeds the 70th percentile condition by about 125 MW and exceeds the 90th percentile water condition by about 300 MW. However, differences in generation capability, of course, vary by month. In the June-August summer period, for example, median exceeds 70th percentile by about 140 MW and median exceeds 90th percentile by about 255 MW. Thus, by adopting the 70th percentile water condition for planning purposes, Idaho Power's generation requirement increases by 125 MW on an annual basis.

Staff does not believe that Idaho Power simply changed its planning criteria in order to make it easier to demonstrate a need for either the proposed Garnet contract in 2001 or the Bennett Mountain project today. Capacity and energy from these types of plants has been a part of Idaho Power's plans even before the events of the past three years.

Need for Power

Idaho Power has just begun preparing its 2004 IRP. As an initial part of that process, the Company has prepared new load forecasts and has analyzed the future balance between loads and resources. The addition of the Danskin plant, the loss of FMC (Astaris) load and a revised load growth forecast have all been included in the new load-resource balance. Based on the new load resource balance, the Company forecasts it will be deficit in the peak hours during the months of June-July and November-December in all ten years of the forecast, even under median water planning and expected load conditions. Summer peak-hour deficiencies are projected to increase from 352 MW in 2005 to 770 MW by 2011. Winter peak-hour deficiencies are expected to increase from 291 MW in 2005 to 574 MW in 2011. (See Attachment No. 1).

Under 70% water and 70% load conditions (the Company's adopted planning criteria), summer peak-hour deficiencies begin in June and are highest in July. In July 2005, the projected peak-hour deficiency is 495 MW, increasing to 928 MW by 2011. Winter deficiencies under low water conditions are expected to be about 210 MW higher than under median water conditions. (See Attachment No. 2).

Under extreme conditions (90% water, 70% load), Idaho Power is peak-hour deficit in all but three months of the year as early as 2005. By 2007, the Company is deficit in all months of the year. The highest monthly peak-hour deficit grows from 552 MW in July 2005 to nearly 1000 MW in July 2011. (See Attachment No. 3).

Clearly the loss of the FMC (Astaris) load combined with the addition of the Danskin plant did not free up enough available capacity that acquisition of new peaking resources could be avoided. The Company's most recent load-resource balance still demonstrates a significant need for capacity and associated energy during peak hours in the summer and winter. Even if the Bennett Mountain plant is built, the Company expects to have significant summer and winter deficits.

Transmission Constraints

Under median water conditions, even with the Bennett Mountain plant, the Company expects that there will be times that it will not be able to import enough power from the Northwest to meet load. As shown by Attachment No. 4, Idaho Power will experience summer transmission constraints beginning in 2007 under normal water and load conditions. Transmission deficiencies of approximately 30 MW in 2007 grow to approximately 400 MW by 2011. Under low water and high load conditions, the summer transmission constraints become even more severe and occur sooner. (See Attachment Nos. 5 and 6). It is very possible that the Company will need to acquire additional peaking resources in the near future if these constraints cannot be relieved or if summertime peak hour loads cannot be reduced.

It should be pointed out that the durations of the transmission constraints are very limited, amounting in some cases to relatively few hours during the month. Although these hours seem fairly minimal, the consequences of the transmission constraints during these hours could be severe. Unless some other means could be found to either reduce peak hourly loads or increase generation, load curtailment would be necessary.

Request for Proposals/Overview of Process

As a consequence of its need for peaking power and the presence of transmission constraints, Idaho Power decided to issue a request for proposals (RFP) in February 2003. The RFP sought proposals for a variety of resource size configurations to supply from 85 MW to 200 MW of capacity and energy during the months of June-August and November-December, beginning in 2005. The RFP noted that Idaho Power would be willing to combine individual proposals to meet the specified capacity. Bids were sought for an initial term of ten years plus the option to renew the contract annually for any or all of the following five years. The RFP clearly stated that proposals would not be accepted from any Idaho Power affiliates.

The RFP indicated Idaho Power's transmission constraints and preferences as to where new generation should be located. The RFP stated that the Idaho Power transmission system has several constraints that would substantially limit the amount of energy that could be transferred from points upstream of the constraints and delivered to the Boise area without the construction of additional transmission reinforcement. The RFP advised respondents that proposals that depend on transfers of energy across the transmission constraints for delivery to the Boise area

would have an extremely heavy burden to demonstrate that sufficient transmission capacity could be made available in time to meet the June 1, 2005 projected delivery deadline.

Because the Company was unsure of the extent to which the Garnet project could be replaced, the Company issued a flexible RFP request. Rather than requesting 100 MW proposals as suggested in the original 2002 IRP, the Company allowed bidders to propose projects up to 200 MW. In the RFP, the Company advised bidders it was willing to consider either power purchase agreements or build and transfer arrangements. Discussions at the pre-bid meeting covered the assumption that for a power purchase agreement to be successful, it would need to provide significant savings to the Company's customers as a result of the bidder's ability to operate the plant as a merchant plant and sell the output from the plant to third parties whenever the Company was not utilizing it.

Bids

Idaho Power received 21 Notices of Intent to bid projects in response to the RFP. Ultimately, the Company received 11 bids by the April 28, 2003 deadline. With one exception, all of the bids involved gas-fired combustion turbine technology. The bids included simple cycle combustion turbine proposals, combined cycle combustion turbine proposals and a biomass proposal.

A bid was prepared representing Idaho Power's own self-build option. The self-build proposal was prepared in response to the RFP and followed all of the same bidding rules. The bid was prepared by the Company's Power Supply group in coordination with Black and Veatch, the project engineer, and The Industrial Company, the project construction contractor. The bid was prepared independently from the Company group who prepared the RFP and from the Company group that evaluated the submitted bids.

Several of the bids were build and transfer proposals, i.e., proposals in which projects would be built by other entities and Idaho Power would take ownership of the project once completed. Other bids were power purchase agreements or "tolling agreements" under which other entities would build and own the project and Idaho Power would purchase and supply gas and pay the project owner to convert the fuel to electrical power at a specified efficiency. In two cases, the same bidder offered multiple proposals.

A tolling agreement is usually structured around a gas-fired facility. Since the purchaser must provide gas to the facility in order to receive power, the purchaser assumes the risk associated with a short exposure to natural gas. A tolling agreement often quotes a heat rate and a variable O&M component, which forms the basis for the dispatch decision. Such an agreement may provide for a fixed capacity payment – usually quoted in $/kW on a monthly or annual basis – that contributes to the fixed expense of the operator or contracting party.

A brief summary of the proposals is as follows:

- A power purchase agreement for 200 MW of capacity from a proposed 1100 MW combined cycle plant to be located in Wyoming.
- A power purchase agreement for output from a proposed 164 MW simple cycle plant to be located in the Treasure Valley.
- A build and transfer agreement for a 120 MW simple cycle plant to be located at a site of Idaho Power's choosing.
- A power purchase agreement for 124 MW of output from a combined cycle plant located in Washington.
- A power purchase agreement for output from a proposed 30 MW simple cycle plant to be located either in Canyon or Payette counties.
- A proposal to purchase, at avoided cost rates, the output from five, separate 10 MW biomass-fired QF projects to be located somewhere in the Treasure Valley area.
- A power purchase agreement for output from a proposed 82 MW simple cycle plant to be located near Mountain Home.
- A power purchase agreement for output from a proposed 130 MW simple cycle plant to be located near Boise.
- A build and transfer agreement for a proposed simple cycle plant to be located in the Mountain View Industrial park at Mountain Home. The proposal included three separate equipment options: 1) a 150 MW GE equipment package, 2) a 157 MW Siemens Westinghouse equipment package, and 3) a 92 MW Pratt and Whitney/United Technologies equipment package. The proposal also included an option to simply purchase the site at Mountain Home. Mountain View Power, Inc. of Boise, Idaho, submitted the proposal.

- A self-build proposal, prepared under a joint teaming arrangement for a 148 MW simple cycle plant to be located at the site of Idaho Power's existing Danskin plant.

Staff believes that the number and variety of proposals was sufficient to give reasonable assurance that all realistic options could be considered and that a competitive price could be obtained. The bids were nearly evenly split between power purchase agreements and build and transfer agreements. Two bids involved combined cycle plants, while nine involved simple cycle plants. Staff believes that more proposals would have been received if not for Idaho Power's need that a new plant be located close to Boise due to transmission constraints. In addition, Idaho Power's need for the plant in only five months of the year may have discouraged some bidders whose proposals relied on sales to other buyers during the remaining months of the year. Staff believes it has become difficult to obtain financing for merchant plants and for developers of projects that do not have a long-term commitment to sell enough power to recover plant costs.

Evaluation of Bids

Idaho Power used a two-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. Proposals from three bidders were eliminated at this stage – one bidder (five biomass QFs) was encouraged to develop its projects through the normal PURPA process, and two bids were rejected because of plant locations outside of Idaho Power's control area.

In the second stage, a more comprehensive evaluation was conducted based on a methodology established with the assistance of R.W. Beck, an independent third-party consultant retained by the Company to assist in the development of the 2003 RFP and evaluation criteria. R.W. Beck also provided further assistance in the review and evaluation of bids.

Idaho Power used a combination of both price and non-price evaluation criteria in its second stage analysis. A 5-year, 10-year and 30-year present worth cost was computed for each proposal. Five and ten-year costs were examined because the RFP sought bids for a minimum initial 10-year term. A 30-year period was also examined because plant life for those proposals

requiring plant construction is 30 years. When a proposal was for less than a 30-year term, unless there were buyout provisions at the end of ten years, it was assumed that the proposal would be replaced in the remaining years with a Company-owned simple cycle plant. The assumed costs for a Company-owned simple cycle plant were obtained from the Company's self-build proposal, scaled up or down proportionately to account for differences in capacity.

Although the Company calculated costs for various capacity factors, bids were evaluated assuming a 20 percent capacity factor reflective of peak hour production in the five months of June, July, August, November and December only.

Transmission costs were considered when evaluating all bids. Idaho Power added its own estimate of transmission costs whenever they were not included in bids, and revised transmission estimates it believed were inaccurate. Although considered in the bid analysis, transmission costs have not been included in the Company's "Commitment Estimate."

Non-price factors were also part of the scoring criteria. The following non-price factors were evaluated.

a. Contract Start of June 1, 2005
b. Dispatchability
c. Purchase Option
d. Performance Guarantees
e. Experience
f. Delivery Assurances
g. Maintenance Scheduling
h. Project Location
i. Construction

To evaluate the bids based on non-price criteria, Idaho Power's evaluation team reviewed the proposals and awarded points to each proposal in each category. Scores for all factors were then totaled for each bid. Staff believes the evaluation criteria were reasonable and not intended to favor one proposal over another.

Gas prices were assumed to be $4.52 per MMBtu in 2005 and were escalated throughout the life of the project based on forecasts available to the Company. The same gas price was utilized for all natural gas-fired project proposals and, as a result, projects with lower guaranteed heat rates had lower fuel costs on a cost per MWh basis.

Power purchase agreements were evaluated on an equal footing with build and transfer proposals by comparing 5, 10 and 30-year costs. Power purchase agreements always included requirements for capacity charges to be paid over time, while build and transfer proposals required up-front payment for the capital investment.

Combined and simple cycle proposals were compared on an equal footing, again, simply by comparing 5, 10 and 30-year costs. Combined cycle plants are more efficient, but also more costly to build. Combined cycle plants are usually less costly than simple cycle plants on a cost per MWh basis because, at high capacity factors, fixed costs can be spread over more megawatt-hours. In order to achieve such a high capacity factor, however, Idaho Power or another project owner would have to be able to market output from a combined cycle plant during those periods when Idaho Power would not need the output. Because the Company evaluated costs using a 20 percent capacity factor, simple cycle plants tended to fare better in the analysis. Staff believes it was reasonable for the Company to base its cost evaluation on a 20 percent capacity factor because that is the capacity factor that would result if the plant were operated solely to meet Idaho Power's needs.

Short List Analysis

After the initial screening was completed, the top five proposals were short-listed and meetings with representatives of the short-listed entities were held in June 2003. The Company sent a document to each of the short-listed bidders detailing the Company's understanding each respective bid. The review of those documents and the meetings with bidder's enabled Idaho Power to clarify bids, such as definitively determining what things were or were not included in the bid, so that a revised second-round analysis could be completed. A copy of Idaho Power's summary of the 5, 10 and 30-year revenue requirements for each proposal, along with a summary of the non-price factor scores is attached in confidential Attachment 7.

As shown in Attachment 7, proposal 8b (Mountain View Power's Siemens Westinghouse proposal) ranked highest. The Company's self-build SCCT option ranked second. Following the meetings with the short-listed bidders and based on the results of the second-round evaluations, the Company pursued final negotiations with these two bidders.

Analysis of Final Candidate Proposals

Additional due diligence meetings were conducted with representatives of the two final bids and final modifications to bids were accepted through September 12, 2003. As a result of its due diligence efforts, Idaho Power was able to identify issues that enabled the Company to successfully negotiate concessions from the developers of the short-listed projects. Based on the final negotiations, the RFP evaluation team made its recommendation to the Company's management, who in turn recommended to the IdaCorp Board of Directors that Mountain View Power, Inc. be selected as the successful bidder.

Project Description

The proposed Bennett Mountain plant will be a nominal 162 MW natural gas fired, simple cycle power plant to be located on an almost ten acre site within the Mountain View Industrial Park north of I-84 and west of State Highway 20 in Mountain Home. The Bennett Mountain site is approximately four miles southeast of the site of Idaho Power's Danskin plant. The facility's combustion turbine is a single Siemens Westinghouse model 501F. The plant site is large enough to accommodate an additional future generating unit and the plant can also be modified to operate as a combined cycle plant at some point in the future.

Operation

If approved, the Bennett Mountain plant will be operated to meet peak-hour loads in the months of June, July, August, November and December. The plant is currently scheduled to be available to meet peak loads in the summer of 2005. While there may be occasional opportunities to market the output of the Bennett Mountain plant during the light load hours of those same months and during heavy and light load hours of other months, Idaho Power does not anticipate marketing a significant amount of Bennett Mountain plant output during these periods. The opportunity for sales of surplus energy will depend on the difference between the market

price of power and the Bennett Mountain plant's cost of production. Because Bennett Mountain is a simple cycle plant, its dispatch cost is higher than combined cycle plants in the region; consequently, it may not often be cost effective to operate the plant to make off-system sales.

During the months when it is expected to be operated, the Bennett Mountain plant will most likely be started several times per week, and perhaps as often as daily, to provide output during the heavy load hours. However, the decision to start and stop the plant will depend on current market conditions, system needs, reliability considerations and the plant's estimated cost of production.

Fuel Supply and Transportation

A major component of the operating costs of a combustion turbine generating plant is the cost of natural gas fuel. 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. 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.

A natural gas fuel supply will be delivered from the Williams Northwest Pipeline that passes less than one mile from the site. Idaho Power has not yet negotiated or entered into any agreements for the purchase of natural gas fuel supplies for the Bennett Mountain plant. However, in general, the approach Idaho Power intends to pursue is as follows: (1) sourcing fuel from several geographic areas, (2) staggering terms of agreements if multiple agreements are executed, (3) incorporate a mixture of forward and spot purchases, and (4) utilize a combination of firm and non-firm or released transportation capacity.

Idaho Power does have 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. The Company's current practice is to discuss longer-term forward gas transactions (such as purchasing gas for July 2004 now) with its Risk Management Committee before execution.

Idaho Power does have existing hedging guidelines for the Danskin Power plant. However, the Company states that it intends to develop its fuel procurement strategy for both natural gas and transportation capacity as well as expanded hedging guidelines and risk

management strategies for both the Danskin and Bennett Mountain power plants. The Company plans to retain an outside consultant to assist in the analysis. Idaho Power anticipates that management of the fuel supply will be done either by Idaho Power personnel or by Idaho Power personnel in conjunction with a third party such as IGI, Inc. Staff recommends that the gas risk management strategies, including hedging strategies and transportation options, be discussed at the next Customer Advisory Committee (CAG) meeting.

First year fuel and O&M costs for the project are currently estimated to be $57.55 per MWh based on a 20% capacity factor and a gas price of $4.52 per MMBtu.

Idaho Power has already purchased firm fuel transportation rights that can be used for both Danskin and the Bennett Mountain projects. Sufficient transportation rights to serve the Bennett Mountain plant are available without a pipeline expansion.

Interconnection to Williams NW Pipeline

For the Bennett Mountain Power plant to access the Williams Northwest Pipeline, an interconnecting pipeline approximately 3,400 feet in length will need to be constructed. Mountain View's bid included an 8-inch diameter pipeline, which will have sufficient capacity to supply the planned 162 MW unit. Idaho Power and Mountain View are currently investigating increasing the pipeline size from 8 inches to 12 or 16 inches in diameter. Idaho Power states that it will most likely elect to increase the pipeline size to 16 inches in diameter. A 16-inch diameter line will be sufficient to fuel two 162 MW units and will also result in a reduced pressure drop between Northwest Pipeline and the Bennett Mountain Power plant.

If Idaho Power elects to increase the pipeline's size to 16 inches in diameter, then Idaho Power rather than MVP will be responsible for the additional cost. This design change will be handled through a Change Order under the Idaho Power-Mountain View Agreement. Idaho Power will own the interconnecting pipeline.

If the pipeline is increased to 16 inches in diameter, then the pipeline would be oversized for just one unit. However, Idaho Power considers the Bennett Mountain site a viable candidate for a future peaking unit. Considering Idaho Power's anticipated future resource needs, Idaho Power believes that incurring the relatively small incremental cost to increase the pipeline capacity at this time is prudent. Idaho Power contends that this is the only additional cost that would be incurred solely to enable additional future capacity to be constructed at the Bennett Mountain site.

While Staff agrees that it may be prudent at this time to increase the size of the interconnecting pipeline, *Idaho Code* §61-502A prohibits utilities from earning a return on property held for future use. Staff recommends that Idaho Power be allowed to recover the incremental cost of a larger pipeline. The upgrade should be booked as Plant Held for Future Use, where it would not be included in rate base or earn a return until the incremental amount is used and useful.

Water Supply and Wastewater Treatment

Mountain View Power has obtained letters of commitment from the City of Mountain Home to provide both water and sewer service for the plant. The City has constructed a network of wells, lines and storage facilities and has substantial water supply capacity and priority water rights. Water will be purchased at city rates for industrial use. Water usage at the plant is primarily a function of the number of hours the plant operates the evaporative cooling system. The ambient temperature during those hours and the number of cycles the water is used also impacts the total water use. The expected range of water usage under different conditions is 38 to 91 gallons per minute.

Wastewater from the plant is, of course, a function of the water used by the plant. The plant will be connected to the city sewer system and sewer rates will be charged based on equivalent dwelling units. The City has already constructed a sewer line to serve the Mountain View Industrial Park. Sewer discharges are expected to range from 10-23 gallons per minute.

Electrical Interconnection

A 230 kV line would need to be constructed between the plant switchyard and Idaho Power's existing 230 kV line located approximately four miles north of the project site. Interconnection studies are still underway regarding the integration of the Bennett Mountain plant into the Company's transmission system. Depending upon the outcome of the studies, one of two plans will be implemented to upgrade transmission on the Boise Bench-Midpoint #2 230 kV line between Mountain Home and Boise. Idaho Power estimates that the more costly upgrade plan will cost $11.6 million, while the least costly will be about $5.5 million. The cost of this transmission upgrade is <u>not</u> included in the project commitment cost estimate.

Project Permits

There are a number of permits that must be obtained in order for the project to be built and operated. Certainly one of the most critical permits is a State air quality permit issued by the Department of Environmental Quality (DEQ). A Final Permit to Construct was issued to Mountain View Power on September 9, 2002; however, the permit was for the operation of an earlier project design. On October 21, 2003, Mountain View submitted an amended application for the same equipment package that is included in the accepted proposal. Idaho Power has stated that Mountain View expects to receive a Permit to Construct on or before December 31, 2003.

The project also requires a Conditional Use Permit from the City of Mountain Home. Such a permit was initially granted on February 12, 2000, and an amended permit was later approved and issued on April 24, 2003. The permit requires that it be acted upon before December 31, 2004.

In order to use the site within the Mountain View Industrial Park, Mountain View Power must obtain a lease from the City of Mountain Home. A draft lease agreement has been prepared and the terms of the lease have been agreed to in principle. Idaho Power states that Mountain View will execute the lease when the Company provides a Notice to Proceed, which it will provide after the Commission issues an acceptable Certificate of Public Convenience and Necessity.

A permit to acquire right-of-way for purposes of constructing an underground pipeline for natural gas interconnection has been obtained from the Idaho Transportation Department. Permits have also already been obtained from the Bureau of Land Management to cross BLM land to construct the electrical transmission line and the natural gas pipeline. Additional permits will be necessary for the project to proceed. Permits will be necessary for such things as demonstrating no impact on fish or wildlife; demonstrating no interference with historic, cultural or archaeological sites; transporting materials and equipment on public highways; confirming no pre-existing site contamination; disposing of excavated materials; insuring compliance with construction noise; building permits and other minor permits.

If any permits necessary to begin construction are not received by Mountain View on or before December 31, 2003, and if such delays invoke penalties or cause additional costs to be incurred, Staff recommends that the Commission insist that ratepayers be held harmless.

Environmental Impacts

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

Mountain View Power does not intend to maintain capability to utilize a secondary source of fuel for the plant, such as diesel fuel. Consequently, there will be no environmental risks from on-site fuel storage.

Capital Cost Commitment Estimate

Idaho Power has negotiated a contract with Mountain View Power containing a firm bid for the completed project in the amount of $44.6 million. Based on this contract, Idaho Power states that it is able to make a reliable estimate of the total capital cost of the project. This estimate, which Idaho Power has termed a "Commitment Estimate" is a good faith estimate of the project's total capital cost based on the contract with Mountain View Power plus certain additional costs the Company knows it will incur but cannot quantify with precision at this time. These additional costs include (but are not limited to) sales taxes, AFUDC on progress payments made to Mountain View Power during construction, the cost of Idaho Power oversight of the project and the cost of capitalized start-up fuel. The Commitment Estimate also covers contingencies such as change orders and other unforeseen events. Idaho Power's Commitment Estimate for the project is $54 million, or nearly $10 million more than Mountain View's bid.

The Commitment Estimate does not include the cost of constructing or upgrading transmission facilities to interconnect the project with the Company's existing transmission system. Interconnection may require construction of a substation adjacent to the plant. The studies needed to fully define interconnection and transmission upgrade costs have not been completed. However, Idaho Power's Delivery Business Unit has provided a preliminary upper limit estimate of $11.6 million to interconnect the project and to upgrade the existing 230 kV transmission system. *Idaho Code* §61-526 requires certificates of public convenience and necessity for generation projects but not for extension of existing transmission systems. Thus, once the new transmission line has been built and is used to provide power to customers, Idaho Power states that it will seek to include these transmission costs in rate base.

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

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

Staff believes that the Commitment Estimate for the project is very reasonable, especially by standards of the past several years. Due to a current abundance of turbines available in the market, Mountain View is able to construct the project at significantly lower costs than similar projects constructed just a short time ago. Idaho Power states that the commitment cost of $54 million for the 162 MW Bennett Mountain project is just $5 million more than the $49 million cost of the 90 MW Danskin project completed in September 2001.

The Idaho Power–Mountain View contract amount of $44.6 million is a known amount that, except for possible change orders, will not change once Idaho Power takes ownership of the plant. Moreover, the amount was established through a competitive bidding process that the Staff finds acceptable. However, those costs above the $44.6 million contract amount, up to the Commitment Estimate of $54.0 million, cannot be quantified with precision at this time according to Idaho Power. Furthermore, those expected costs will not be subject to a competitive bidding process, nor to the advance scrutiny of the Commission or its Staff. Consequently, Staff recommends that these expected costs (up to a maximum $ 9.4 million) be subject to audit by the Commission Staff, and that the Commission withhold rate base consideration of these costs until after the project is constructed and the audit is completed.

Total Expected Power Cost

Based on Idaho Power's economic analysis of the proposal, including the upper end estimate of $11.6 million for the cost of transmission and the Mountain View contract amount of $44.6 million, the cost of energy from Bennett Mountain will be $78 per MWh over a ten-year

period based on a 20% capacity factor. The 20% capacity factor assumes the project will only be utilized during the peak hours of need June, July, August, November and December.

It is important to realize that the plant's estimated energy costs are highly dependent on its capacity factor, i.e., how much time the plant actually operates in a year. For instance, if Idaho Power operates the Bennett Mountain plant at less than a 20% capacity factor, the fixed costs of the project would be spread over fewer kilowatt-hours, making the price per kWh higher. On the other hand, if Idaho Power operates the Bennett Mountain plant at more than a 20% capacity factor, the overall cost per kWh would be less. For example, at a 40% capacity factor, the cost of energy would drop to $60 per MWh, and at a 60% capacity factor the price is $54 per MWh when analyzed over a 10-year period.

Similarly, if the cost of energy from Bennett Mountain is analyzed over 30 years, the expected life of the plant, the cost of energy decreases even further. Assuming a 20% capacity factor, the energy cost is $44.61 per MWh. At a 40% capacity factor the price is $35 per MWh, at 60% the price is $32, and at an 80% capacity factor the price drops to approximately $30 per MWh. Analysis at various capacity factors and over various lengths of time is important in order to make comparisons with other proposals. It is also important so that comparisons can be made to other alternatives, such as market purchases, existing contracts and other generating resources.

Staff believes that the most accurate indication of the long-term cost of power from Bennett Mountain is the 30-year cost at capacity factors ranging from 20 to 80%. Staff believes that as the Company's loads increase over time, it is likely that the plant will operate at increasingly higher capacity factors, possibly eventually being converted to a combined cycle plant.

It is also extremely important to recognize that the price of energy computed for analysis purposes is highly dependent on the cost of gas that is assumed in the analysis. Idaho Power's analysis assumed a starting gas price of $4.52 per MMBtu, with prices in future years based on various forecasts available to the Company. These estimates are reasonably based on today's gas prices and forecasts, but prices could turn out to be much different than assumed in this analysis. Because each of the proposals considered by Idaho Power in the final analysis proposed to use gas as fuel, the effect of different gas prices was similar on each proposal's cost, except to the extent some projects may have been more efficient than others.

Idaho Power notes that the 10-year, 20% capacity factor price of $78 per MWh is very similar to the ten-year cost of $77 per MWh that was anticipated for the Garnet contract.

However, unlike the Garnet project, this project will be available year round rather than just during certain months of the year. Whereas the Garnet contract offered significant discounts from total project costs in order to retain a merchant role for their project, the Company states that projects can currently be developed at lower costs such that today's undiscounted project costs are similar to discounted Garnet costs. Ultimately, as market conditions changed, merchant projects were considered risky and the Garnet project could not obtain acceptable financing. It should also be noted that the Garnet contract evaluation assumed gas prices of $3. 75 per MMBtu whereas the RFP evaluation process assumed gas prices of $4.52 per MMBtu in 2005.

In its Application and accompanying testimony, Idaho Power compared the dispatch cost of Bennett Mountain to the cost of its recent six-year, summer heavy load hour contract with PPL Montana. The total first year fuel plus variable O&M cost for the Bennett Mountain project is expected to be $57.55 per megawatt hour compared to the $44.50 per megawatt hour cost (not including transmission cost) of the PPL Montana contract. However, it is important to remember that the PPL Montana contract is a take or pay contract whereas Bennett Mountain would be dispatchable. If Bennett Mountain does not need to be operated, fuel costs can be avoided.

It is difficult to make a comparison to other market alternatives because it could be argued that the market is not really an alternative to the Bennett Mountain plant due to transmission constraints. However, just for the sake of comparison, Staff tabulated nine years of the monthly heavy load hour prices as shown by the 2002 IRP for the months in which Bennett Mountain is expected to operate. This tabulation is shown in Attachment 8. As indicated by the tabulation, the average forecasted market price during the months Bennett Mountain is expected to operate is approximately $60 per MWh. This is lower than the $78 per MWh 10-year average energy cost estimated for Bennett Mountain. It is important to note, however, that power from Bennett Mountain may not be taken during all heavy load hours during a day. In addition, the forecasted prices from the 2002 IRP are probably somewhat stale and will be different as forward market prices change and as gas price forecasts change.

Another indirect comparison can be made to prices recently forecasted by the Northwest Power and Conservation Council. As a part of the upcoming Fifth Northwest Power Plan, the Council intends to include long-term price forecasts for various locations throughout the West. Attachment 9 is a preliminary draft forecast to be included in the Plan. The draft forecast shows the Council's predicted on-peak and off-peak prices for southern Idaho. Note that the Council is

forecasting on-peak prices to begin peaking in the summer of 2006, reaching levels above $150 per MWh in August 2011. Because the forecast prices are monthly average on-peak prices, Staff would expect that some days in each month would have prices substantially above the prices shown. Further confirmation of extreme hourly prices is illustrated by Attachment 10, the Council's forecast of Mid-C prices for four different time segments in each week. Forecasted prices for Segment 1 (the 8 a.m. to 6 p.m. weekday time period) exceed $200 per MWh in the summer of 2008. The Council's forecasted prices referred to here were prepared before the recent increase in gas prices; consequently, comparable prices would be even higher using current gas prices. The gas prices assumed by the Council were lower than the prices used by Idaho Power in its analysis. Again, although these are only forecasted prices, they do provide at least a rough basis for comparison to the $78 per MWh estimated cost of energy from Bennett Mountain.

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

Project Risks

There will be some risk associated with the Bennett Mountain project simply because it uses natural gas for fuel. Just because Idaho Power will own the Bennett Mountain plant does not mean the Company will escape the risk exposure it would otherwise have if it relied on the electric market. Gas prices, while perhaps being historically less volatile over the short term due to the ability to store significant amounts of gas, can still be quite volatile. Owning gas-fired generation could perhaps ultimately lead to slightly greater rate stability than if the same output were purchased from the market.

Furthermore, if market purchases were a realistic option, there could be credit uncertainties with many counterparties, both regulated and unregulated. The tenuous financial health of many energy companies is reflected in recent ratings downgrades and bankruptcy filings in the industry. As just one close to home example, Idaho Power's recent agreement with PPL Montana for 83 MW requires a transmission agreement with NorthWestern Energy, whose parent company recently filed for Chapter 11 bankruptcy. Although the transmission agreement is not believed to be in jeopardy, it nevertheless illustrates the potential risk of relying on the market for long-term supply.

Project Benefits

Staff believes there are several notable benefits to the proposed Bennett Mountain project. First, the cost of the project is very attractive, primarily due to the availability of the combustion turbine at a bargain price. Staff estimates that the cost of the turbine for this project will be far less than it would have been just two years ago. Turbine prices are currently extremely low because equipment destined for new plants now has nowhere to go due to numerous plant cancellations, the financial difficulties of many developers, and the demise of others.

Second, the Bennett Mountain project appears to have strong local acceptance. Mountain View Power has worked closely with the Mountain Home community to gain support for the project. Staff is not aware of any local opposition. Permitting of the plant is nearly complete.

Third, the proposed Bennett Mountain plant is in close proximity to the Danskin plant, enabling possible sharing of operational staff and equipment. The plant site is also reasonably close to the Company's primary load center in Boise, minimizing transmission constraint concerns.

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

Finally, the Company will have two expandable sites (Danskin and Bennett Mountain) at which to place additional gas-fired resources if future IRPs identify such generation resources as the resource of choice.

IDAHO POWER – MOUNTAIN VIEW AGREEMENT

Idaho Power has negotiated an Asset Purchase and Sale Agreement (Agreement) with Mountain View Power, Inc. Mountain View, in turn, has contracted with Siemens Westinghouse Power Corporation to furnish all of the labor, equipment and materials and to perform all of the engineering and construction of the project. Idaho Power's contract with Mountain View provides that if Mountain View defaults, Mountain View shall assign its rights and obligations under contracts with Siemens Westinghouse and its major subcontractors to Idaho Power. Thus, Idaho Power effectively can "step-through" Mountain View and work directly with Siemens Westinghouse to complete the project. As a result, Idaho Power can rely on Siemens Westinghouse and the financial strength and experience of both Siemens Westinghouse and its parent, Siemens Corporation, to assure the performance of the contract and the successful completion of the project. Upon completion of construction and passage of the necessary performance tests, including guaranteed net capacity and guaranteed heat rate, title to the project will transfer from Mountain View to Idaho Power.

Responsibilities of Idaho Power, Mountain View Power, and Siemens Westinghouse

Idaho Power is responsible for construction of the 230 kV switchyard and the transmission line needed to interconnect the project to the Company's existing transmission system. The Company must also provide operators and pay for any start-up fuel and electricity used in commissioning the plant. Mountain View is responsible for obtaining all permanent facility permits and licensing. Siemens Westinghouse will perform all other tasks necessary to build the plant, including engineering, equipment and materials procurement, construction, operator training, and performance testing.

Liquidated Damages

The Asset Purchase and Sale Agreement between Idaho Power and Mountain View Power (Agreement) contains liquidated damages for project delays or turbine performance shortfalls. If the Siemens-Westinghouse gas turbine has not been delivered to the site by December 1, 2004, $10,000 per day in liquidated damages will be assessed against Mountain View. Mountain View is required to have the project approximately 95% complete by year-end 2004. Completion of construction and all performance testing of the project, including

guaranteed capacity and guaranteed heat rate, must be completed by April 1, 2005. Project ownership will transfer to Idaho Power at that time provided that all provisional acceptance criteria identified in the contract have been satisfied. Liquidated damages of $5,000 per day in April, $10,000 per day in May, $15,000 per day in June and $20,000 per day thereafter will be assessed for a delay in achieving provisional acceptance. If the plant fails to achieve guaranteed net capacity and net heat rate, liquidated damages will be assessed based on the level of performance shortfall. Idaho Power contends that a back-loaded payment schedule insures that Mountain View Power and Siemens Westinghouse have adequate incentive to see the project through to completion.

Experience of Mountain View Power

Mountain View Power claims experience in the development of at least six simple cycle combustion turbine projects with a combined total capacity of nearly 2,000 MW. Mountain View also claims to have developed at least seven combined cycle plants totaling over 3,000 MW. Mountain View is Boise based, although some of the principals are not local.

Mountain View Power is too small to be rated by any credit rating agency. Idaho Power is relying on the credit of Siemens Westinghouse Power Corporation and its parent, the Siemens Corporation, for the credit support for the Bennett Mountain project.

Financing and AFUDC

There are no special and/or separate financing arrangements for the construction of the Bennett Mountain plant. Idaho Power will make progress payments to Mountain View during construction. Idaho Power will finance the plant's construction through its normal corporate financing process.

Idaho Power's request in this case includes recovery of AFUDC. Even though Mountain View Power will own the project until ownership is transferred to Idaho Power in April 2005, the Company contends AFUDC is appropriate for recovery as a project cost because the Company is helping to finance the project by making progress payments. Such financing, Idaho Power alleges, allows for a lower total cost to ratepayers than if Mountain View Power were to finance the project in a different manner.

Recovery of AFUDC is typically allowed only in instances where the utility itself is performing the construction. In this case, however, Staff agrees that recovery of AFUDC should be allowed based on the project price reduction. If Mountain View were to completely finance the project, Mountain View's financing costs would have to be added to the total project cost. The AFUDC Idaho Power will otherwise incur should be allowed up to the $2,500,000 project price reduction. Idaho Power Company should be required to justify any additional amounts with a cost/benefit analysis prior to inclusion in rates.

Super Bonus Depreciation Tax Benefits

Officially known as "additional first-year depreciation allowance," bonus depreciation was made law in 2002, and was expanded as "super bonus depreciation" in 2003. Under the expanded law, for assets placed in service after May 5, 2003, 50% of a qualifying asset's basis can be claimed as depreciation in its first year of service, in addition to normal tax depreciation on the remaining basis. If an asset meets the applicable date restrictions, a significant portion of the project's costs would qualify for the 50% first year deduction. In the case of Bennett Mountain, 95% of the project costs are expected to be incurred by December 31, 2004 and will be eligible for the bonus depreciation. Spending during 2005 would be eligible for the normal tax depreciation rules. This bonus depreciation provides value to Idaho Power by increasing cash flow. Customers receive the benefit of increased deferred taxes in early years as a reduction to rate base. The increased first-year tax depreciation is approximately $28 million with increased deferred taxes of approximately $10 million. Idaho Power is seeking an order in this case by December 31, 2003, in part, to accommodate a construction schedule that maximizes its ability to utilize super bonus depreciation.

It is unlikely that the planned construction schedule will allow 100% of the plant equipment to qualify for bonus depreciation. One of the liquidated damages provisions in the Asset Purchase and Sale Agreement between Idaho Power and Mountain View is specifically intended to provide a strong incentive for Siemens and Mountain View to accelerate the manufacture and delivery of the largest portion of the plant equipment in an ongoing course of construction to maximize the qualification of assets for bonus depreciation.

The Company's tax department was consulted because of potential bonus tax depreciation benefits that could be derived based upon percentage of completion of power plants by December 31, 2004. Bidders were encouraged to prepare their construction schedules to

maximize the tax benefits while at the same time ensure that they would not complete the project too far in advance of the Company's identified need in June 2005. Mountain View Power was very cooperative in proposing a schedule that would complete 95% of the project by year-end 2004, but ownership of the project would not be transferred until April 2005.

Tax Increment Financing

In preparation of its bid, Mountain View explored whether the City of Mountain Home could form an urban renewal district, thereby allowing use of tax increment financing on qualifying portions of the project's infrastructure. By using tax increment financing (TIF), project development costs could be reduced. Mountain View, in preparing its project bid, estimated these savings at $3 million, and possibly higher. Qualifying improvements could include gas pipeline interconnection, electrical interconnection, water supply and sewer interconnection, storm water management systems, road access, communication facilities, and site grading. Section 2.3 (b) of the Agreement provides that TIF may cause the base price of the project to increase.

Idaho Code §50-2001 *et seq* provides for TIF. Formation of an urban renewal district is possible because the Mountain View Industrial Park is located within the city limits of Mountain Home. If the City appropriately forms an urban renewal district, the City could then issue economic development bonds to pay for infrastructure improvements. The bonds are then retired by using the net increase in property tax payments attributable to the increased value of property resulting from the urban renewal improvements in the district.

Staff recommends that to the extent tax increment financing reduces project costs beyond the $3 million amount included in Mountain View's bid, that any additional savings be passed on to Idaho Power. In other words, TIF in excess of $3 million should not increase the price paid to Mountain View or be included in rate base. Any change in the base price due to TIF in excess of $3 million should be reviewed in a subsequent proceeding.

Sales Taxes

Sales taxes on purchase of the combustion turbine for the project were not included in Mountain View's bid, but sales taxes on the balance of plant and other equipment were included. Because the turbine intended for the project has been purchased from the secondary market, sales

and use taxes have already been paid by the previous buyer and can be applied against Idaho sales tax obligations.

OTHER ALTERNATIVES CONSIDERED

Staff does not believe that by simply issuing an RFP, Idaho Power can be assured that it will automatically be presented with all viable alternatives. Staff believes that many other alternatives should be considered besides construction of a new generation plant. Because Idaho Power's needs are driven primarily by peak-hour loads and transmission constraints of short duration, it makes sense to make all cost-effective transmission upgrades and to implement all cost-effective load management programs prior to, or in addition to, acquiring power from a new plant. Not all of these alternatives will necessarily prove viable or be able to alleviate the need for new generation, but they should at least be examined. Possible alternatives include market purchases, upgrades or additions to existing generation facilities, additional transmission upgrades, load management programs, traditional demand side management programs, and various pricing options.

Even if the Commission approves Bennett Mountain, not all of the Company's anticipated deficiencies are satisfied by Bennett Mountain. The potential to implement cost-effective DSM alternatives still exists.

Market Purchases

Idaho Power states that it is not aware of any market products that are capable of providing Idaho Power's system with capacity and energy comparable, or nearly comparable, to the 162 MW of internal generation provided by the Bennett Mountain plant during its first five years of operation. Several alternatives to replace the defunct Garnet project were identified in the Garnet Report. These alternatives included firm wholesale purchases delivered to the east side of Idaho Power's system and a firm wholesale purchase or exchange involving an existing resource located within Idaho Power's control area. While each alternative is possible, Idaho Power does not believe either is comparable to the 162 MW of dispatchable internal generation that Bennett Mountain would provide.

Of these listed alternatives, Idaho Power believes firm wholesale purchases delivered to the east side of its system would be the least desirable because they 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. Firm wholesale purchases or exchanges involving existing resources

located inside Idaho Power's control area would be more desirable because import capacity would still be available for emergencies. Furthermore, depending on contract terms, Idaho Power's ability to dispatch the existing resource would most likely be limited. Finally, Idaho Power believes a dispatchable resource such as Bennett Mountain, strategically located in Idaho Power's control area, is the most desirable for three reasons: (1) the reliability benefits associated with having another generator on-line inside the control area, and (2) preservation of import capacity for system emergencies, and (3) the operational flexibility associated with a dispatchable unit.

If market products were available inside the Idaho Power control area and were capable of being delivered to the Boise area, then Staff believes they probably would be comparable to the cost of new generation. The problem, according to Idaho Power, is that a sufficient quantity of these products are not available inside Idaho Power's control area, and if they were available at Idaho Power's border, internal transmission constraints could prevent them from being delivered to the Boise load area. This is why, Idaho Power states, the 2003 RFP specified the product as being a generating resource located inside the Idaho Power control area.

Even if Idaho Power could rely on the regional power market as an alternative to building new generation, as was demonstrated in 2000 and 2001, Staff believes 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.

There is also considerable uncertainty going forward, Staff believes, as to the continued availability of long-term market products. Just a few years ago there were West-wide plans for thousands of megawatts of new merchant generation. Of those planned capacity additions, extremely few have materialized. Many merchant sector developers and marketers have exited the business. Some utilities, including Idaho Power, have closed their power market affiliates. For some of the remaining power market participants, credit issues have become a major concern. Over the long term, Staff believes it will be more difficult in the future for utilities to rely on the market as much as they have in the past.

Conservation

Traditional energy conservation (examples include lighting retrofits, building insulation, efficient appliances, energy codes, etc.) should be an ongoing part of all utilities' IRP programs whenever cost effective. Idaho Power has recently reintroduced conservation programs for its irrigation and industrial sectors. Both programs pay financial incentives to customers that modify existing systems or install new efficient systems, however, both will primarily result in kilowatt-hour savings, rather than reductions in demand.

Conservation programs of the past, as well as programs underway now, have certainly proven that energy usage can be reduced cost effectively. However, even the most successful conservation programs take time to have an impact and can rarely eliminate the increasing load growth that must be met. Conservation programs cannot, in Staff's opinion, achieve enough demand reduction, nor can they achieve it quickly or reliably enough, to realistically satisfy the Company's immediate need to meet growing peak loads. Furthermore, traditional conservation is usually spread over all hours and is not necessarily focused on the super peak hours of need identified by Idaho Power. As a result, traditional conservation was not considered a viable stand-alone option to issuance of an RFP for new generation.

Load Management

Staff inquired as to whether Idaho Power considered any load management programs, rate designs or other strategies that could reduce the Company's peak load during those months or hours when the Bennett Mountain plant is expected to operate. Idaho Power responded that it had contracted with Quantum Consulting to perform a Peak Load Reduction Assessment within its service territory. The purpose of the study is to identify potential peak reduction opportunities within the residential and commercial customer classes. The study has yet to be completed and will not likely be available until at least January 2004.

1. Air Conditioning.

The increase in residential and commercial air conditioning is obviously one of the primary contributors to Idaho Power's increased summer peak hour loads. In its Application in this case, Idaho Power cited its air conditioner cycling pilot program as an example of its efforts to implement load management. The first season of the pilot just concluded in August 2003. Under the air conditioner cycling pilot, nearly 400 participants will ultimately be selected. Idaho

Power will manage air conditioning use between 1 p.m. and 9 p.m. for up to 10 days a month from June through August, turning it off no more than 15 minutes at a time. The air conditioner cycling program targets heavy-load hours between June and August. If it is ultimately determined that an air conditioner cycling program is a cost-effective way to reduce critical system peaks, such a program would address essentially the same peak periods of time that are the primary concern addressed by Bennett Mountain, and could potentially mitigate the continuing need for additional resources similar to this project.

2. Water Heating.

Idaho Power has not investigated water heating load control. Although water heating does not exhibit the same seasonal load shape as air conditioning, seasonal load control can have a similar effect as air conditioning load control. A recent study by Portland General Electric showed 100% customer acceptance of water heating load control, but less than 80% customer acceptance when it came to air conditioning load control. The cost effectiveness of water heating load control proved to be higher as well. Staff is not suggesting that air conditioning load control be abandoned, but rather that the Company investigate water heating load control with equal vigor.

3. Energy Exchange.

During 2001, in response to extremely high market prices and low water conditions, Idaho Power implemented an Energy Exchange program for its largest commercial, industrial and large irrigation customers. Participating customers were required to be able to reduce their electrical load by 1000 kW at each meter point. Under this voluntary load reduction program, Idaho Power offered to credit customers half of the then current market price for each kWh reduced during declared Exchange Events. An Exchange Event was a set of hours during which Idaho Power would ask participants to reduce their electric load during specific hours on specific days. Exchange Events would be announced for the day of, day ahead, or two days ahead of an Event. Exchange Events were guaranteed to be a minimum of two consecutive hours. Participating customers could then specify which hours and days they wished to reduce their load. Idaho Power could then accept or reject the offer of load reduction.

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

4. Irrigation.

Idaho Power has never tested a load management program for its irrigation customers. PacifiCorp, however, made interruptible rates available to all of its irrigation customers in the past. Last summer, PacifiCorp introduced a new irrigation load management program. An evaluation report on the program was recently submitted to the Commission on November 28, 2003 in Case No. PAC-E-03-3. According to the evaluation report, 207 irrigation customers representing 402 pumping sites participated in the program. This represents approximately 10% of the customers eligible to participate. Under the program, participants agreed to have their loads interrupted up to 12 hours per week in exchange for a credit for the utility. Interruptions were pre-scheduled for each customer at the beginning of the season. Credit amounts were also determined at the beginning of the season. According to the program evaluation, PacifiCorp's Idaho peak irrigation load was reduced by 18-24 MW, depending on the day of the week and the month during the season. The report concludes that the program is cost effective. PacifiCorp intends to continue the program next season with few modifications. If a similar program were implemented by Idaho Power, Staff believes the results could be scaled up to reflect the greater number of Idaho Power irrigation customers.

Alternative Rate Designs

Time-of-use (TOU) rates and interruptible rates, particularly for those customer classes whose summertime usage is most responsible for causing the high hourly peaks, are alternative rate designs that could be viable options. TOU rates charge customers a higher rate during on-peak hours. One of their objectives is to entice customers into shifting their usage to times of the day when demand is lower. PacifiCorp, for example has offered TOU rates for residential customers for many years. Interruptible rates are another possible mechanism to achieve a

similar goal. PacifiCorp has offered interruptible rates to its irrigation customers for many years as well.

Idaho Power cites its rate design proposal in its pending general rate case, IPC-E-03-13, as one effort to possibly reduce peak load requirements. The Company's filing includes the proposal to establish seasonal pricing for all residential, commercial and industrial customers and to establish TOU pricing in addition to seasonal pricing for all industrial customers. Under the Company's proposal, prices for energy and demand will be higher during the three summer months of June, July and August and additionally for industrial customers during the peak hours of the day. Because irrigation usage is already seasonal, irrigation rates are also seasonal.

Idaho Power also recently investigated the potential for TOU rates for residential customers, but never implemented a program or conducted a pilot. Based on its analysis, the Company concluded that the potential benefits of such a program were insufficient to outweigh the costs of installing a metering system capable of TOU metering and the lost revenues associated with power sales during off-peak periods. The Company is, however, currently planning to implement an automated meter reading (AMR) pilot project, and TOU rates may be included as part of the program.

Idaho Power introduced a TOU pilot program for irrigation customers in the summer of 2001, partly in response to the extremely high market prices. Under this pilot, participating irrigation customers are billed three different rates depending upon when their usage occurs. Usage during the peak afternoon and evening hours is billed at the highest rate while usage during the nighttime hours is billed at the lowest rate. Over the course of the pilot, 228 irrigation customers participated in the program. Following the 2002 irrigation season, Idaho Power submitted its final report on the pilot program. It appears that participating customers shifted 11% of load from on-peak hours in the first year and 7% in the second. Idaho Power concluded, however, that the program was a losing proposition due to the fact that it lost more revenue from kilowatt-hours being billed at lower rates than it saved from the lower cost of energy it purchased at off-peak prices. (See Case No. IPC-E-01-6).

In the case of the irrigation pilot program, the Energy Exchange Program for large commercial and industrial customers, and in the case of TOU metering analysis for residential customers, Staff believes there are extremely important benefits to the programs that the Company repeatedly overlooks. In its analysis of each of these alternatives, Idaho Power looks only at the immediate costs and revenues associated with the programs, and fails to consider the

long-term impacts. It is true that each of these programs reduces revenues below current levels and that if the difference between on-peak and off-peak prices is minimal, the program may not seem cost effective. However, the simple fact that a program reduces critical peak hourly demand has great value, especially if peak hourly demand is what dictates Idaho Power's need for new generation. The value of reducing critical peak hourly demand equals the value of eliminating or deferring the need for new generation. This value has been completely neglected by Idaho Power in its program analysis. Perhaps if this value were considered, these types of demand reduction and load management programs would be judged to be cost effective.

It may have been true in the past that TOU and interruptible rates were not cost effective for Idaho Power because of its ability to meet peak loads through the peaking capability of its hydro plants. For many years, Idaho Power was energy constrained rather than capacity constrained. Now, however, Idaho Power is capacity constrained rather than energy constrained. The Hells Canyon Complex is no longer capable of being ramped up and down enough to meet peak hourly loads.

It is interesting to note that PacifiCorp has had both interruptible rates and TOU rates for many years. Because PacifiCorp has historically been mostly dependent on coal-based generation, it has not had the capability to meet peak loads as easily as hydro-based utilities. Thus, PacifiCorp has had more incentive for programs and rate designs that encourage load shifting. Now, Idaho Power is facing similar constraints in meeting peak loads, yet it is failing to fully recognize the benefit of load shifting measures.

Conversion of Danskin to Combined Cycle

Conversion of the Danskin simple cycle plant to a combined cycle plant would increase its capacity from 90 MW to 129 MW. While converting Danskin to combined cycle certainly improves plant efficiency, the conversion has been estimated to cost $1559/kW – much higher than the cost of new simple cycle capacity. Considering Idaho Power's peaking needs and the cost of combustion turbines at the time the RFP was being developed, converting Danskin to combined cycle was not considered an economical alternative. Instead, adding an additional 148 MW simple cycle unit at the Danskin site was considered as an alternative (i.e., the Company's self-build alternative). Conversion of the plant to combined-cycle may be a more attractive option for meeting future load growth, particularly if Idaho Power develops a need for base load resources.

Renewables and PURPA QFs

It has sometimes been suggested that if Idaho Power embraced renewables or increased its avoided cost rates so that more PURPA QFs would be viable, that its need for new generation could be satisfied. The Commission's decision about a year ago to increase the threshold for published rates to ten MW and to lengthen the standard contract length to 20 years may spur the development of additional independent power projects. It is unknown, however, how much additional capacity might be developed and when such development might occur. It is very unlikely that enough additional capacity would be developed soon enough to meet Idaho Power's current capacity needs because it has taken nearly 25 years to develop a comparable amount since the inception of PURPA.

Staff does not believe that either renewables or PURPA QFs are well suited to meet the extreme peaking needs of Idaho Power. Idaho Power's 2003 RFP did not restrict the types of projects eligible to bid. No renewables bids were received that met the requirements of the RFP. The primary reason, Staff believes, is that no renewables projects are able to deliver energy and capacity in only five months of the year at a cost competitive with gas-fired generation. New projects that produce power at times when Idaho Power does not need it are not really helpful in meeting its peak hourly loads that occur only in the summer and winter. Moreover, PURPA projects typically are not dispatchable, thus they cannot be used just to help meet the peaking needs of Idaho Power.

Transmission Upgrades

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. Idaho Power has been upgrading a portion of its transmission system to reduce this constraint. The Brownlee to Oxbow project is expected to be completed and in service by the summer of 2004 (item no. 4 on page 2). It will increase the Brownlee East capacity by approximately 100 MW. Even with these improvements, however, Idaho Power's transmission system is still constrained at certain times.

Idaho Power contends that additional transmission upgrades that would relieve its constraints and increase access to Northwest markets would be more costly than other alternatives and would be expected to take at least 8 years to complete. In its 2002 IRP, the Company estimates that transmission upgrades to further access Pacific Northwest markets

would add $10 to $20 per MWh to purchased energy prices; with even higher costs if some of the transmission capacity is not subscribed.

Shoshone Falls

In its 2002 IRP, Idaho Power identified an upgrade to its Shoshone Falls plant as one means of helping to meet load through 2008. An upgrade at the plant would add approximately 64 MW of capacity. It was initially anticipated that capacity expansion of the Shoshone Falls plant would be completed in conjunction with its scheduled FERC relicensing application to be filed in 1997, and that the expansion would be completed in 2004. At present, Idaho Power is awaiting a new FERC license for the Shoshone Falls power plant. Rather than modifying the currently pending license application, Idaho Power intends to wait until a new license is issued before proceeding with permitting for the Shoshone Falls upgrade. Idaho Power expected to receive the new license in late 2002; however, the new license is yet to be issued. If a new license is received in the next month or so, then a 2007 in service date for the upgrade is still possible. If receipt of the license continues to be delayed, the Shoshone Falls upgrade will most likely be delayed until 2008 or later.

Although the Company still intends to proceed with the upgrade project, Staff believes it holds no promise for helping to meet peak summer and winter loads. The generation at Shoshone Falls is minimal in the summer due to nearly complete diversion of the Snake River upstream at Milner, and flows in the winter are generally not high enough to permit any increased capacity to be utilized.

Bennett Mountain's Effect on Danskin

Once the Bennett Mountain plant becomes operational, it is likely that it will dispatch before the Danskin plant given the difference in heat rate, or efficiency, between the two plants. At 90 degrees, Danskin's heat rate is approximately 11,900 Btu/kWh while Bennett Mountain's heat rate is approximately 10,600 Btu/kWh. Converting those heat rates to fuel costs, using a hypothetical natural gas price of $4.00/MMBtu, the fuel cost per MWh generated by Danskin is $47.60/kWh while the fuel cost for power generated by Bennett Mountain would be $42.40/MWh – a savings of over $5/MWh. Ultimately the operation of each plant will depend on numerous factors including power prices, system needs, transmission constraints, unit availability, and variable O&M costs.

Both plants are intended to meet Idaho Power's peak load requirements in the summer and winter daytime hours. With the Bennett Mountain plant not yet online, the Danskin plant operated slightly more than 500 hours during 2002, and operated approximately 475 hours through September of 2003. Both years have been considered low water years in which above normal thermal generation and market purchases have been required. Since first going online in August 2001, Danskin has operated in all but two months. Once Bennett Mountain becomes available, however, Danskin will likely operate far less hours. Both plants will need to be operated at times during the summer daytime hours, but still, Staff believes Danskin's operation could easily be cut in half from its current operational level.

Future Needs

It is likely that Idaho Power will need additional peaking resources in the future. The 2002 IRP identified the need for approximately 450 MW of capacity and energy to satisfy deficiencies primarily in three summer months and two winter months. The plan was to utilize 250 MW from the Garnet project, acquire another 100 megawatts via an RFP and establish market purchases of approximately 100 megawatts. The Garnet project will not be built and the PPL Montana contract has replaced only 80 megawatts of that 250 MW project. With the addition of Bennett Mountain at 162 MW, 242 MW of required capacity will have been acquired. That leaves approximately 208 MW to be acquired via the market or development of additional projects. That 208 MW amount is 108 MW greater than the level of planned market purchases in the 2002 IRP and, according to the Company, exceeds its comfort level for resource adequacy.

Idaho Power is currently in the process of preparing the 2004 IRP, which will investigate both the magnitude and timing of the Company's future resource needs. Possibly, the 2004 IRP may recommend issuance of additional RFPs. While Idaho Power has no firm plans at present to issue additional RFPs during the next five years, the Company reports that RFPs for wind generation, DSM, and additional peaking resources have been discussed, as well as the need for future base-load resources. These alternatives will be considered in the 2004 IRP.

RECOMMENDATIONS

Staff is convinced that Idaho Power has demonstrated a genuine need for peaking power in the months of June July, August, November and December beginning in 2005. The request for proposals, the criteria used by Idaho Power to evaluate bids, and analysis of the bids was fair to all proposals, Staff believes. Consistent with prior orders, Idaho Power has evaluated a range of cost-effective power-conservation resources. The Company has also provided a Commitment Estimate as a rate base cap. Staff concurs with Idaho Power that Mountain View Power's proposal for the Bennett Mountain project is superior to the other proposals received.

Staff recommends that the Commission issue to Idaho Power a Certificate of Public Convenience and Necessity to construct the Bennett Mountain plant. Staff believes that in the ordinary course of events the Commission may authorize the ratebasing of the amount of the Mountain View Agreement amount of $44.6 million. Staff recommends that the actual amount of capital costs to be rate based above the bid price of $44.6 million up to the Commitment Estimate of $54 million be subject to review in a subsequent case. If the Commission approves the project for rate base treatment, Staff recommends that Idaho Power be ordered to provide the Commission with periodic percentage of completion and cost expenditure reports during the construction phase. Staff also recommends that the audit capabilities allowing Idaho Power access to Mountain View's books be extended to the Commission Staff. This will allow verification of the final costs.

Staff also recommends that the Company be strongly encouraged to diligently continue to investigate and, where warranted, begin implementing conservation, load management and pricing options that could potentially displace or defer the need for additional future peaking generation.

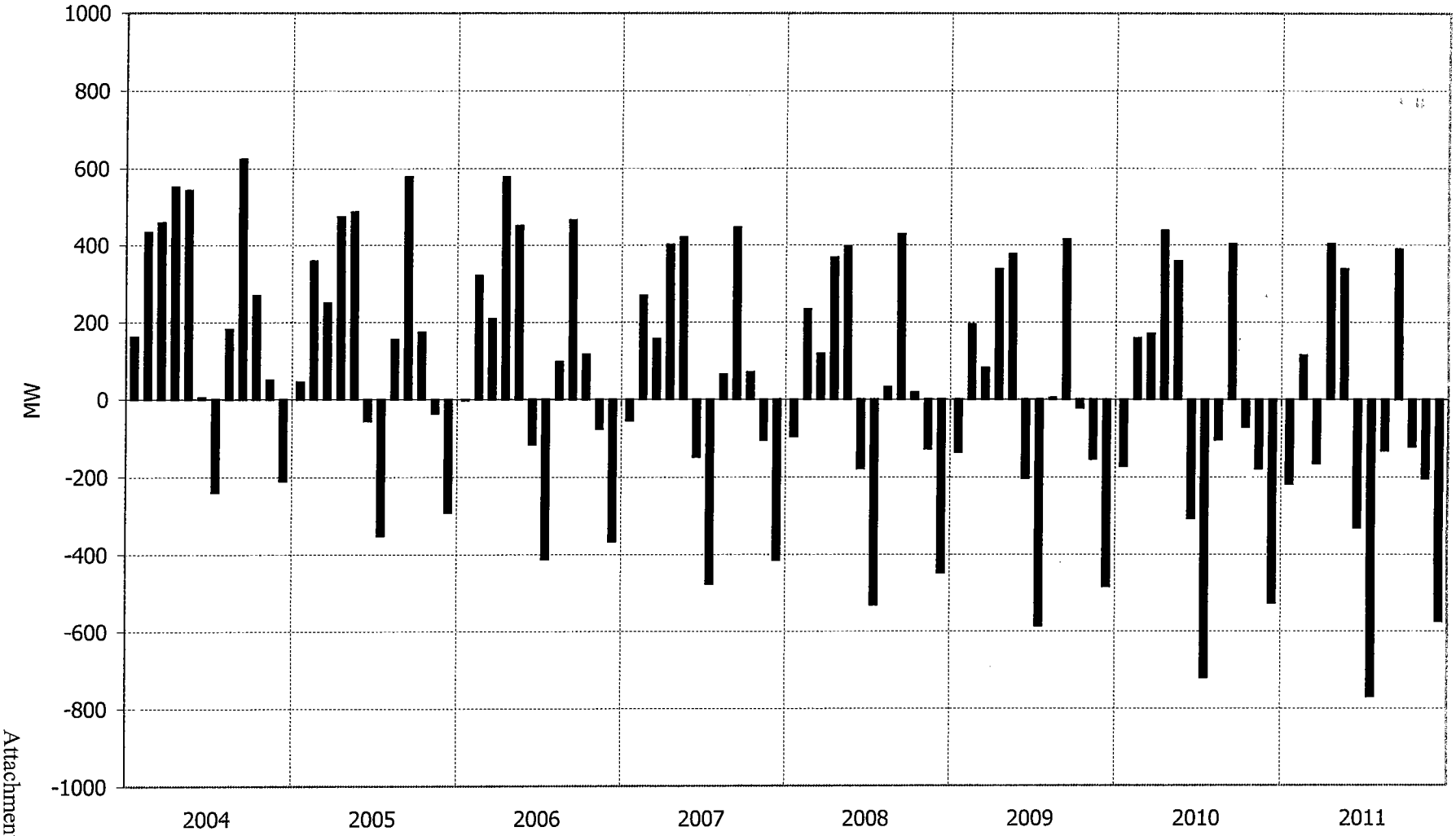
Respectively submitted this 15th day of December 2003.

Donald L. Howell, II
Deputy Attorney General

Technical Staff: Rick Sterling
Terri Carlock

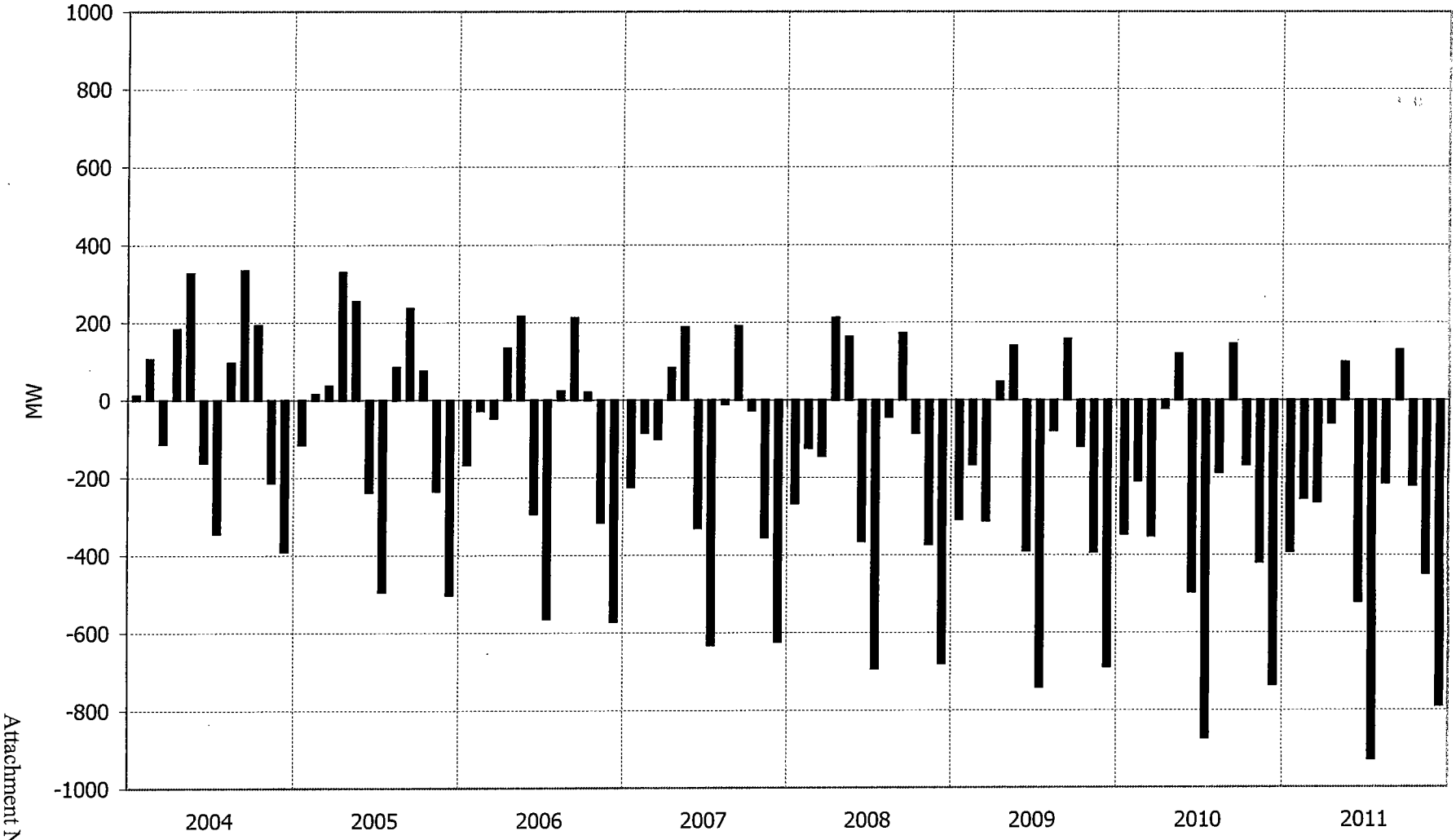
i:umisc:comments/ipce03.12dhrps

Monthly Peak-Hour Load Resource Balance Data
50% Water, 50% Load, Bennett Mountian Not Included



Attachment No. 1
Case No. IPC-E-03-12
Staff Comments
12/15/03

Monthly Peak-Hour Load Resource Balance Data
70% Water, 70% Load, Bennett Mountian Not Included



Attachment No. 2
Case No. IPC-E-03-12
Staff Comments
12/15/03

Monthly Peak-Hour Load Resource Balance Data
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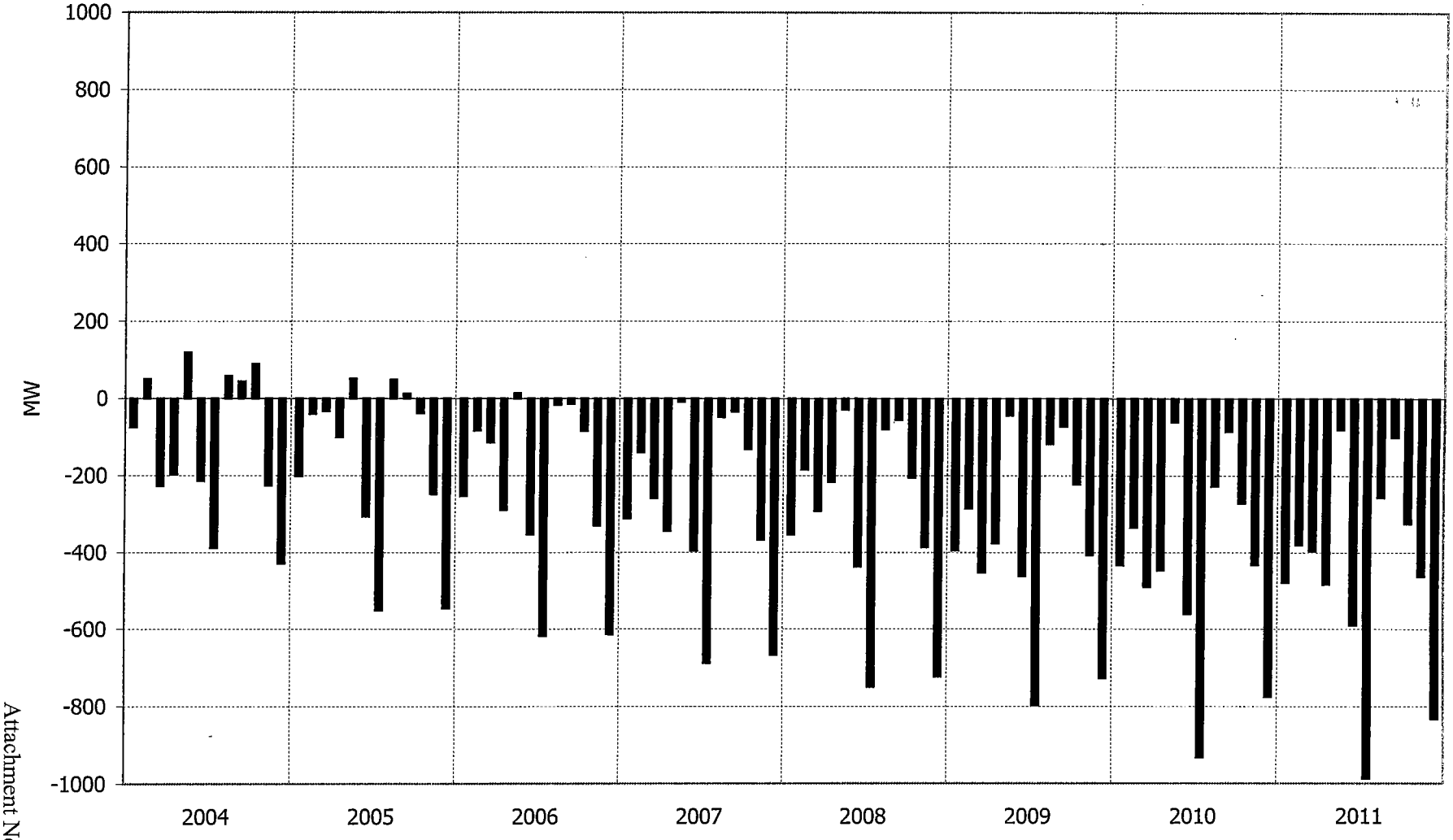
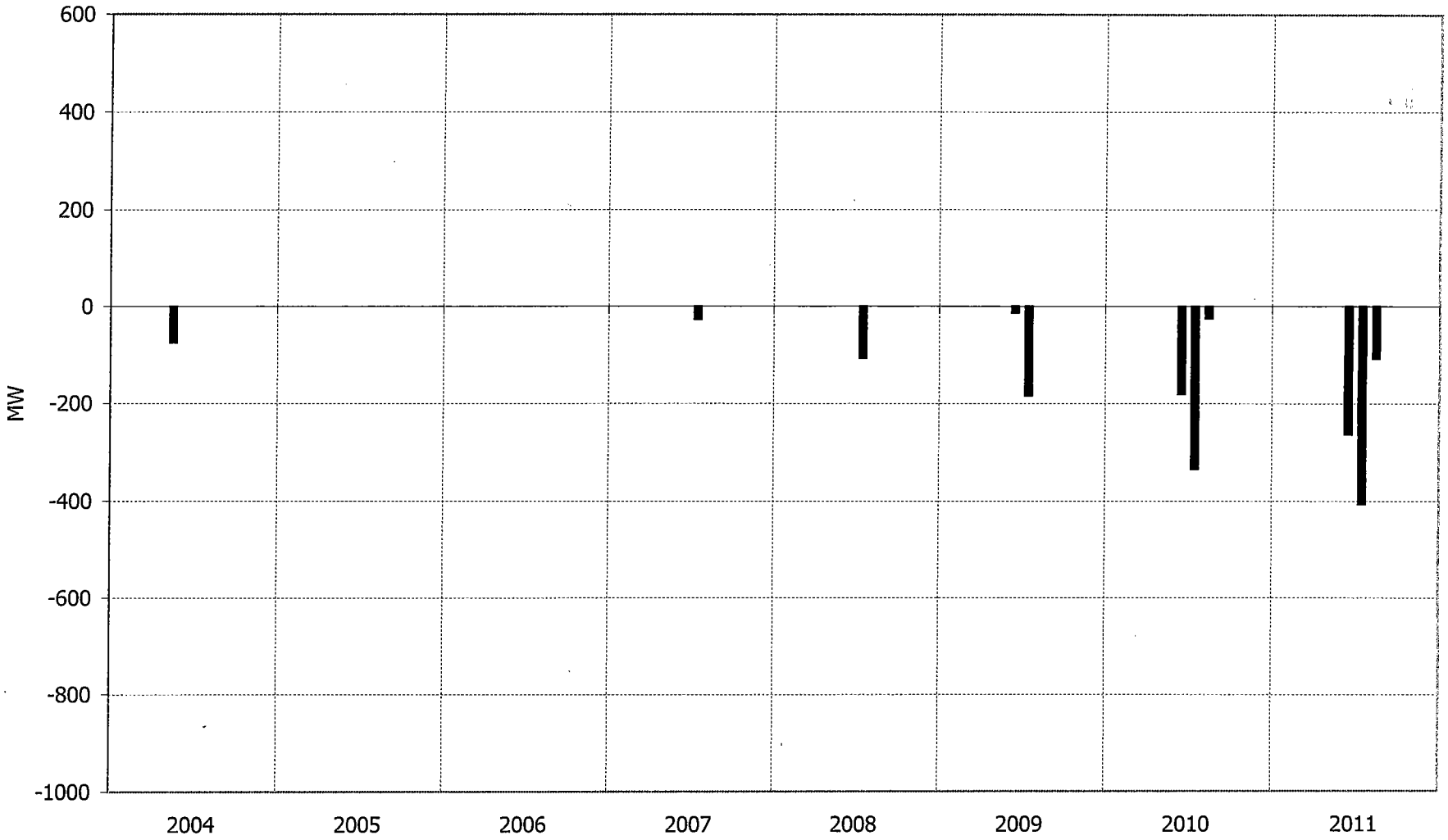


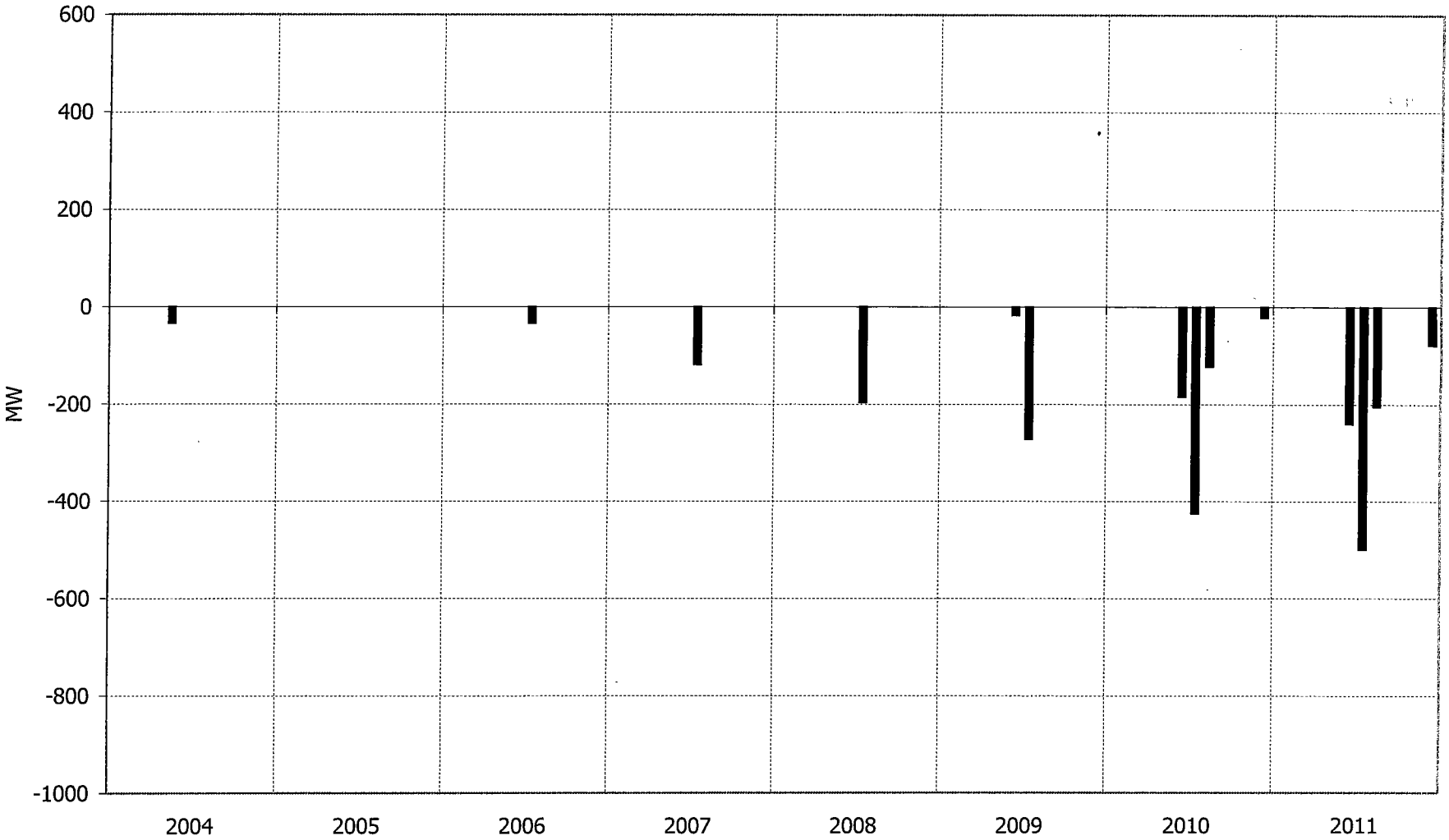
Attachment No. 3
Case No. IPC-E-03-12
Staff Comments
12/15/03

Northwest Transmission Deficit Data
50% Water, 50% Load, Bennett Mountain Included



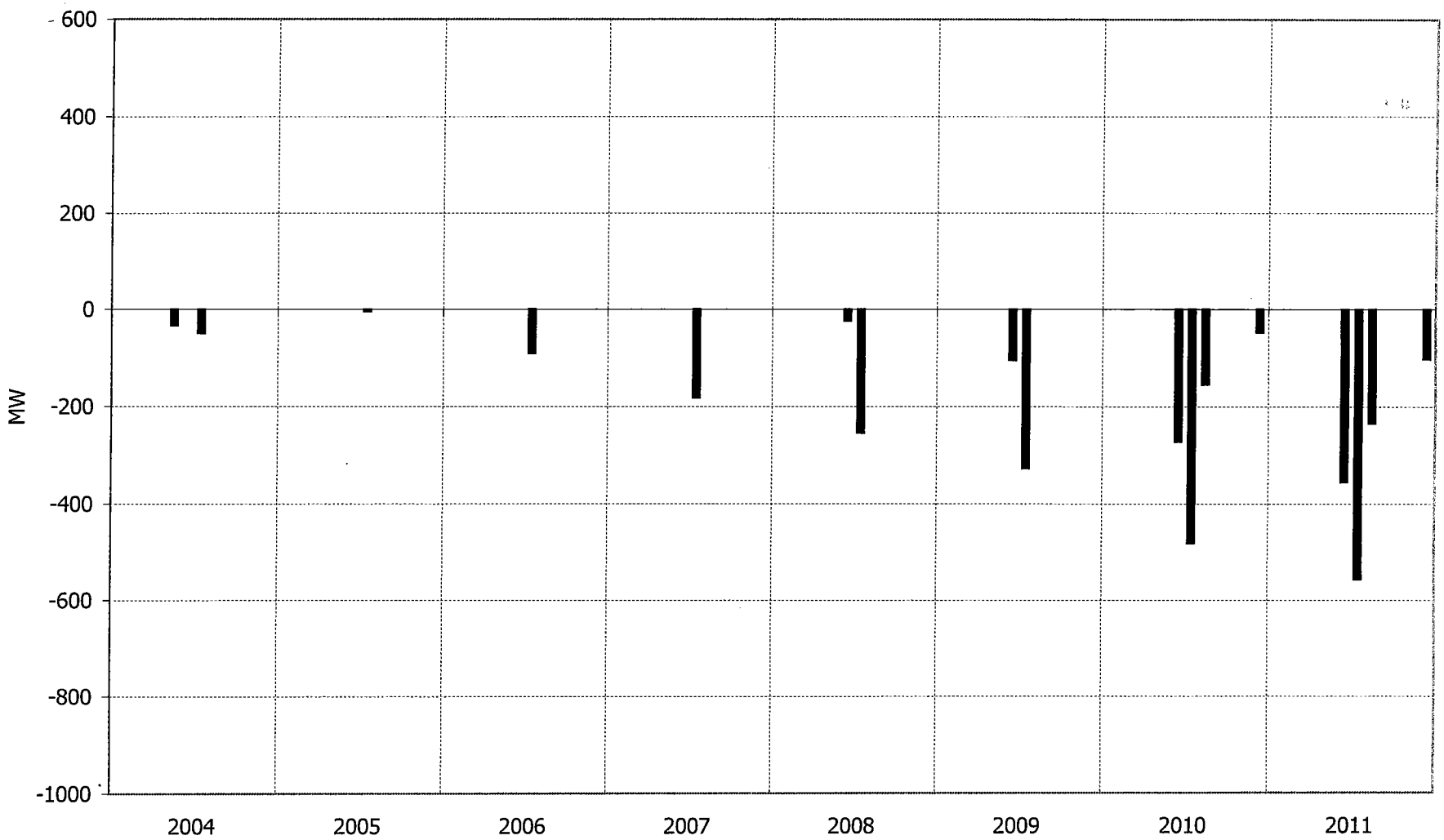
Attachment No. 4
Case No. IPC-E-03-12
Staff Comments
12/15/03

Northwest Transmission Deficit Data
70% Water, 70% Load, Bennett Mountain Included



Attachment No. 5
Case No. IPC-E-03-12
Staff Comments
12/15/03

Northwest Transmission Deficit Data
90% Water, 70% Load, Bennett Mountain Included



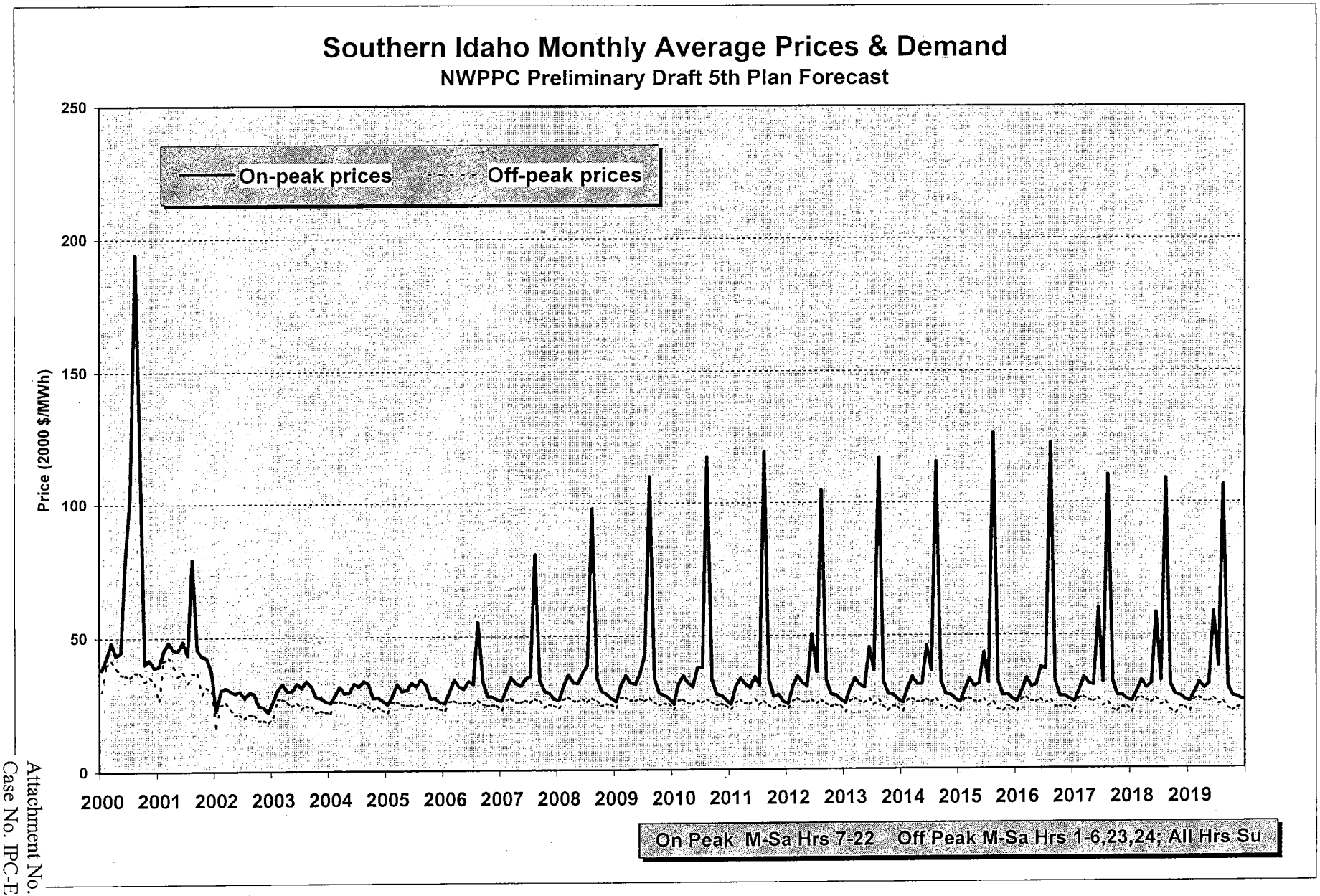
Attachment No. 6
Case No. IPC-E-03-12
Staff Comments
12/15/03

ATTACHMENT NO. 7 IS CONFIDENTIAL

2002 IRP
Electric Price Forecast
Mid C Heavy Load Hour Prices

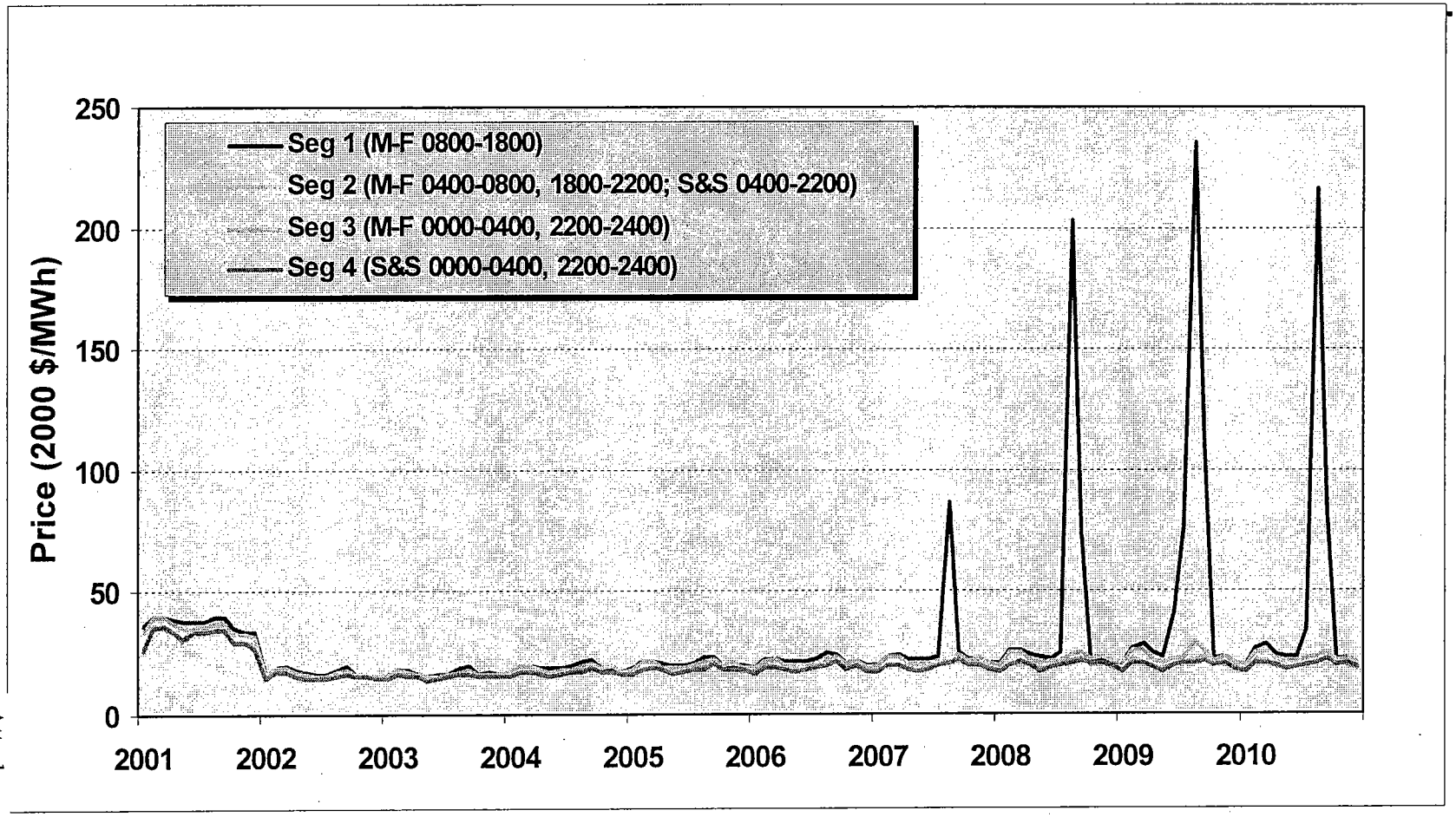
	Month	Price ($/MWh)	Source
2005	Jun	25.72	Forward Market Price as of March 15, 2002
	Jul	38.45	Forward Market Price as of March 15, 2002
	Aug	44.95	Forward Market Price as of March 15, 2002
	Nov	38.97	Forward Market Price as of March 15, 2002
	Dec	42.61	Forward Market Price as of March 15, 2002
2006	Jun	26.44	Forward Market Price as of March 15, 2002
	Jul	39.53	Forward Market Price as of March 15, 2002
	Aug	46.21	Forward Market Price as of March 15, 2002
	Nov	40.06	Forward Market Price as of March 15, 2002
	Dec	43.80	Forward Market Price as of March 15, 2002
2007	Jun	36.48	AURORA Base Case Price Forecast V 6.1.3
	Jul	46.65	AURORA Base Case Price Forecast V 6.1.3
	Aug	121.70	AURORA Base Case Price Forecast V 6.1.3
	Nov	40.71	AURORA Base Case Price Forecast V 6.1.3
	Dec	41.08	AURORA Base Case Price Forecast V 6.1.3
2008	Jun	43.39	AURORA Base Case Price Forecast V 6.1.3
	Jul	46.90	AURORA Base Case Price Forecast V 6.1.3
	Aug	129.65	AURORA Base Case Price Forecast V 6.1.3
	Nov	43.88	AURORA Base Case Price Forecast V 6.1.3
	Dec	41.70	AURORA Base Case Price Forecast V 6.1.3
2009	Jun	41.64	AURORA Base Case Price Forecast V 6.1.3
	Jul	47.93	AURORA Base Case Price Forecast V 6.1.3
	Aug	140.80	AURORA Base Case Price Forecast V 6.1.3
	Nov	46.13	AURORA Base Case Price Forecast V 6.1.3
	Dec	43.44	AURORA Base Case Price Forecast V 6.1.3
2010	Jun	41.47	AURORA Base Case Price Forecast V 6.1.3
	Jul	50.06	AURORA Base Case Price Forecast V 6.1.3
	Aug	146.23	AURORA Base Case Price Forecast V 6.1.3
	Nov	44.72	AURORA Base Case Price Forecast V 6.1.3
	Dec	44.11	AURORA Base Case Price Forecast V 6.1.3
2011	Jun	43.58	AURORA Base Case Price Forecast V 6.1.3
	Jul	53.71	AURORA Base Case Price Forecast V 6.1.3
	Aug	149.10	AURORA Base Case Price Forecast V 6.1.3
	Nov	45.51	AURORA Base Case Price Forecast V 6.1.3
	Dec	46.61	AURORA Base Case Price Forecast V 6.1.3
2012	Jun	46.61	AURORA Base Case Price Forecast V 6.1.3
	Jul	66.91	AURORA Base Case Price Forecast V 6.1.3
	Aug	150.17	AURORA Base Case Price Forecast V 6.1.3
	Nov		AURORA Base Case Price Forecast V 6.1.3
	Dec	49.05	AURORA Base Case Price Forecast V 6.1.3
2013	Jun	46.36	AURORA Base Case Price Forecast V 6.1.3
	Jul	57.28	AURORA Base Case Price Forecast V 6.1.3
	Aug	155.41	AURORA Base Case Price Forecast V 6.1.3
	Nov		AURORA Base Case Price Forecast V 6.1.3
	Dec	50.11	AURORA Base Case Price Forecast V 6.1.3
	Average	60.14	

Attachment No. 8
Case No. IPC-E-03-12
Staff Comments
12/15/03



Attachment No. 9
Case No. IPC-E-03-12
Staff Comments
12/15/03

Mid-C four-segment monthly averages



Northwest Power Planning Council: April 2002

Attachment No. 10
Case No. IPC-E-03-12
Staff Comments
12/15/03

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **15TH** DAY OF DECEMBER 2003, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-03-12, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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VICE PRESIDENT – POWER SUPPLY
IDAHO POWER COMPANY
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Terri D. Koch
SECRETARY