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February 16, 2007

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket No. LC 41

Pursuant to the discussion at the Prehearing Conference held on February 5, 2007, Idaho Power provides the enclosed courtesy copies of Report on CHP Project and the comments filed in its Idaho 2006 IRP docket—IPC-E-06-24.

Very truly yours,

Lisa F. Rackner

Enclosures
cc: Service List

STATUS REPORT
February 2006

POTENTIAL CHP LOCATED IN EASTERN OREGON

In the spring of 2005, Idaho Power was advised by a large industrial customer it was beginning the process of searching for a development partner for a potential combined heat and power (CHP) project at its processing facility located in eastern Oregon. After selecting a developer, Idaho Power was notified CHP projects ranging in size from 30 – 130 MW were being considered by the developer. As required under PURPA for QF projects larger than 10 MW, Idaho Power began negotiations with the developer to determine if a pricing methodology and contract terms could be agreed upon.

After several months of negotiations, the initial developer stopped communicating with Idaho Power and the facility owner notified Idaho Power it had approached other developers with an interest in the project. In addition to working with other developers, the facility owner expressed an interest in trying to work out an arrangement directly with Idaho Power whereby the utility would build a natural gas-fired plant for the purposes of generating electricity and providing steam for the owner's processing facility.

In August of 2006, Idaho Power hired a consultant to perform a feasibility study for the construction of a CHP project at the site. The study was completed in December 2006 and the facility owner and Idaho Power are in the process of evaluating the options proposed in the study which range in size from 16 to 48 MW. Idaho Power's 2006 IRP identifies a 50 MW CHP resource to come on-line in 2010 and Idaho Power is investigating this project as a potential way to meet that need.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2006 INTEGRATED RESOURCE PLAN.	**CASE NO. IPC-E-06-24** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Cecelia A. Gassner, Deputy Attorney General, in response to the Notice of Filing and Notice of Comment Deadline in Order No. 30185 issued on November 21, 2006, submits the following comments.

BACKGROUND

On September 24, 2006, Idaho Power Company ("Idaho Power" or "Company") filed its 2006 Integrated Resource Plan (IRP). On October 18, 2006, the Company filed a revised plan that corrected certain typographical errors and revised certain exhibits. The Company's filing is pursuant to a biennial requirement established in Commission Order No. 22299, Case No. U-1500-165. The IRP describes the Company's growing customer base, load growth, supply-side resources, demand-side management and risk analyses. Additionally, the 160-page IRP document and related appendices contain information regarding available resource options, planning period forecasts, potential resource portfolios, a twenty-year resource plan, and a near-term action plan.

THE INTEGRATED RESOURCE PLAN

The IRP filing consists of five documents: the IRP, a Sales and Load Forecast, the Company's 2005 Demand-Side Management Annual Report, an Economic Forecast, and a Technical Appendix.

Idaho Power has worked with stakeholders over the last 12 months to develop the subject IRP. The Integrated Resource Plan Advisory Council (IRPAC) consisted of members of the environmental community, major industrial customers, agricultural interests, an Idaho state legislator, Commission Staff, a representative from the Idaho Governor's Office, and others. The Company also conducted presentations open to the general public from November 13-16, 2006 in Boise, Pocatello, and Twin Falls, Idaho, and Ontario, Oregon.

According to the Plan Summary, the Company anticipates that its customer base will increase from approximately 455,000 to over 680,000 by the end of the planning period of 2025, an increase of 11,000 to 12,000 new customers each year. The Company states that it used a conservative resource plan based upon a worse-than-median hydro conditions. It used 70^{th} percentile water conditions and 70^{th} percentile average load for energy planning. In addition, for peak-hour capability planning, it used 90^{th} percentile water conditions and 95^{th} percentile peak-hour load.

The IRP states that it includes 1,300 MW (nameplate) of supply-side resource additions and demand side management (DSM) programs designed to reduce peak load by 187 MW and average load by 88 aMW. The Company's average load and summertime peak load are expected to increase by 40 aMW and 80 MW, respectively, per year through 2025.

The Company states that the 2006 IRP provides the Company's estimate of future loads and sets forth how the Company intends to serve the electrical requirements of its native load customers over the next 20 years. While the proposed resource portfolio represents current resource acquisition targets, the Company notes that the actual resource portfolio may differ from the quantities and types of resources outlined in the IRP depending on responses to the Company's Requests for Proposals, the business plans of any ownership partners, and the changing needs of Idaho Power's system.

Idaho Power conducted an analysis of possible transmission path upgrades, and the following were selected as the most viable transmission alternatives:

- McNary (Columbia River) to the Locust Substation (Boise) via Brownlee;
- Lolo (Lewiston area) to Oxbow;
- Bridger, Wyoming to the Boise Bench Substation via the Midpoint Substation;
- Garrison or Townsend, Montana to the Boise Bench Substation via the Midpoint Substation; and
- White Pine, Nevada to the Boise Bench Substation via the Midpoint Substation.

The IRP's preferred portfolio includes a 250 MW coal-fired resource addition in 2013 identified as "Wyoming Pulverized Coal." The Company does not know specifically where this addition will be located, but states that one of the Company's best near-term alternatives for expansion at an existing coal-fired resource is the addition of a fifth unit at the Jim Bridger plant.

STAFF ANALYSIS

General Comments

Idaho Power continues to make strides in producing a quality resource plan. The 2006 IRP has built upon the well-received 2004 IRP by adding additional analyses to the portfolio selection process and incorporating recommendations made by the Commission in the previous filing. Staff believes that through the interaction with the IRPAC, increased rigor in the scrutiny of portfolios, extended planning horizon, and inclusion of regional transmission capacity projects, the 2006 IRP is superior to prior filings.

There have been numerous events that have happened since the 2004 IRP that have influenced the 2006 analysis; most of these have been accounted for in the planning process. The 2006 IRP assumes the approval of the 170 MW addition to the Danskin facility. Also assumed in the analysis is the net upgrade of 49 MW to the Shoshone Falls Hydroelectric Project first identified in the 2002 IRP and scheduled for completion in 2010.

The Company continues to use a more conservative water, load, and peaking capacity planning criteria in this IRP process as it did in the 2004 IRP. While wholesale market prices for electricity have shown less volatility than in prior years, some risk remains for excessive reliance on regional markets to meet the Company's summer peaking needs. This risk is somewhat mitigated through the use of conservative planning criteria and the Company's risk management process.

The 2006 IRP includes 250 MW of additional wind resources, including a 100 MW project currently in the latter stages of the RFP process. There is also a 50 MW geothermal project in the latter stages of the RFP process included in the chosen portfolio. The Company's Plan appears to take a reasoned approach to developing a diversified portfolio that includes fossil fuel-based resources, more renewable resources, and increased DSM in its future resource mix.

Staff believes that the Company is justified in extending the planning horizon from ten years to twenty years in order to incorporate more capital intensive resources that require a longer lead time than the recently acquired simple cycle combustion turbines. The extended horizon also facilitates the analysis of transmission planning, which requires sufficient lead time for permitting and construction as well. The longer planning horizon does result in a somewhat speculative assessment of unproven or uncertain resources. For example, inclusion of an integrated gasification combine-cycle (IGCC) coal plant seems speculative given the Company's caveats about the immaturity of the technology, and the 250 MW power purchase agreement with Idaho National Laboratory (INL), scheduled for 2023, for nuclear power is highly uncertain.

However, the IRP is not intended to be a binding plan for the future expansion of the Company, and time and changing conditions will ultimately dictate the actions of the Company. The additional sensitivity analysis, discussed in more detail below, is an appropriate enhancement of the planning process to account for factors beyond the Company's control. Continued cooperative development of future IRPs with the IRPAC and the general public, along with advances in the Aurora modeling software, will enhance Idaho Power's ability to identify and evaluate uncertainty associated with the various resource portfolios.

Load Growth Forecasts

Idaho Power continues to plan for a high level of growth in load over the planning horizon. The expected growth rate of 1.9% is lower than the 2002 and 2004 IRPs, but still signifies a robust upward trend. When compared to the 2004 IRP, this change in the growth rate results in a reduction of expected load by 71 aMW in 2013. Of the four main customer classes, the residential sector appears to be the catalyst for growing load. The growth rate for residential customers is predicted to be about 2% annually, resulting in a net increase of nearly 190,000 customers by 2025 for that class. This contributes to both energy and capacity needs, with emphasis on the latter due to the growing penetration of air conditioning within the service territory. Summer peak load growth is projected at 80 MW a year over the planning horizon, with residential and irrigation accounting for approximately 60% of summer peak demand. Staff notes, and details below, that Idaho Power has implemented and expanded cost-effective DSM programs to these customer classes with the intent of mitigating peak load growth.

Fuel Price Forecasts

The results from the Company's analysis are based on assumptions made and inputs used in the modeling runs. None may be as important, given recent events, as the natural gas price forecast. In the past five years the Company has relied primarily on the addition of gas-fired combustion turbines to meet increased peaking needs. Other electric utility providers have acted similarly, and nationally this trend has increased total gas consumption for electric generation by 45% over the past decade. In that period the nation has also seen unprecedented volatility in gas prices (which was not predicted by the majority of well-established sources), which the Company relies on to derive the price schedule used in its analysis. The 2006 IRP includes a high natural gas price scenario in its portfolio analysis, and annual average prices of $8.23/MMBTU, which is in the lower range of prices witnessed in 2005 or 2006. The graph comparing natural gas price forecasts from the 2000 to 2006 IRPs included on page 49 of the Technical Appendix illustrates the inability to accurately predict fuel prices. In each case the prior forecast was well below the preceding forecast, demonstrating the volatile and somewhat unpredictable rise in natural gas prices recently. As an example, the 2004 IRP uses an expected (Sumas) natural gas price of $4.85/MMBTU and a high scenario of $6.27/MMBTU. The 2006 IRP portfolio analysis uses prices of $8.23/MMBTU for the expected scenario and $11.16/MMBTU for the high gas price, an increase of 70% and 78% respectively in two years.

Even though there are no new gas-fired plants included in the selected portfolio, there are ramifications to using optimistic gas forecasts, namely that alternative resources can be shown to be less competitive. Combustion turbines fired by natural gas have historically enjoyed an economic advantage in the decision making process due to the low relative initial capital cost and stream of variable fuel costs based on relatively low fuel price forecasts. Gas price forecasts are critical in determining which resources are included in the portfolio. This is especially true when high capital costs/low fuel cost resources are compared to resources with high fuel costs and low capital cost. Although the Company has included a significant amount of renewable resources in its selected portfolio, it has also indicated that a failure to acquire cost effective geothermal resources and other renewables, combined with favorable gas price forecasts, could result in a need to add additional natural gas-fired facilities in the short term.

Beyond the accuracy of gas price forecasts is the nature of the forecast represented in the IRP. The IRP appears to present and utilize an annual average gas price. Because the majority of gas is purchased to fire turbines in the summer peaking months, it would seem more appropriate to use a summer pricing schedule that reflects the timing of the Company's fuel purchases. To the extent the summer gas prices for use in summer peak facilities are lower than annual average prices (that include the higher winter prices), then the risk of an artificially low annual average forecast is somewhat mitigated. To the extent the Company used weighted summer prices in its IRP, it should describe the methodology used in the calculation.

The Company's forecast of coal prices continues to exhibit the same upward trend in forecasts from the previous IRPs. IRP, Technical App. D at 50. Coal prices do become a major factor in assessing potential portfolios, as the Company appears committed to adding coal-fired resources to the mix. The steep upward trend in coal prices predicted to begin around 2012 supports the Company's position to split its coal acquisition into two segments, including 250 MW of IGCC in 2017. A major driver in coal prices is transportation costs, namely rail transport, which can be critical in the siting of the plant. Idaho Power does not identify the location of their proposed coal facility in 2013, though it mentions expanding the Jim Bridger facility in Wyoming as a potential addition. The Company is also in discussions with Avista for possible joint acquisition of a coal-fired resource.

Transmission

At the behest of the Commission, Idaho Power included transmission alternatives in its resource planning. Results from the Company's analysis show peak hour transmission deficiencies as early as 2007, and significant long-term deficiencies beginning in 2009. Though the Company has transmission interconnections to the Southwest markets, the bulk of the analysis focuses on the Pacific Northwest markets. Given the Company's needs, availability of economical resources, and the maturity of the Pacific Northwest markets, it appears the emphasis on transmission upgrade is properly focused. The 2006 IRP does a far better job of incorporating transmission constraints in the portfolio selection analysis than previous IRPs.

FERC's Standards of Conduct prohibit potentially beneficial discussion between the Company's planning and transmission groups. In order to incorporate transmission alternatives into the IRP, Idaho Power contacted an outside consultant to provide the technical evaluation of several alternatives. It appears that the resulting selections of possible transmission upgrades are reasonable, though more detail regarding the findings of the consulting group would have been beneficial. The Company has included in its selected portfolio 285 MW of transmission upgrades that provide access to the Mid-C market in the Pacific Northwest. Given the nature of electric usage profiles of utilities in Washington, Oregon, and Northern California, Idaho Power may have significant opportunities to utilize additional transmission capacity for off-system purchases during summer months and periods of low water.

The Borah-West transmission upgrade, detailed in the 2004 IRP, will serve to support the growing number of wind and geothermal projects to the east of Boise, but as noted by the Company, additional upgrades will be necessary should the Company site a coal-fired plant in Wyoming. The

IRP states that since a site has not been identified, generic transmission upgrade costs have been included in the IRP analysis. Although there is uncertainty associated with current transmission upgrade costs, it is likely that the Company will provide a more thorough transmission cost estimate when a more fully developed plan to acquire resources east of Boise is presented.

Supply Side Resource Options

The selected portfolio is a modified version of the preferred portfolio from the 2004 IRP. The modifications took into account the recommendations of the Commission in Order No. 29762 and incorporated a more current assessment of the Company's needs. The three most significant changes are the timing of the additional coal based resources, the inclusion of transmission upgrades, and the modification of geothermal resources. Also, the inclusion of 250 MW of nuclear power in 2023 is worth noting. The selected portfolio consists of the following:

250 MW Wind
150 MW Geothermal
150 MW Combined Heat & Power (CHP)
250 MW Coal
250 MW IGCC Coal
285 MW Transmission
250 MW Nuclear
187 MW DSM (Peak reduction)

Idaho Power has committed to adding more wind generation to its portfolio. The preferred portfolio contains 250 MW of new wind acquisitions over the next ten years, down from the preferred portfolio in 2004 (350 MW). A major factor toward the reduction in new wind acquisitions is the amount of PURPA wind projects the Company has added since the preparation of the 2004 IRP, when it had only 2.61 MW of wind-related contracts. The Company has indicated that, including the 100 MW proposal soon to be submitted for approval and its PURPA commitments, it estimates nearly 300 MW of wind resources in its resource mix by the end of 2007. Excluding any unforeseen additional PURPA contracts, this amount will move to 450 MW within six years.

The 2006 preferred portfolio increases the amount of geothermal-powered generation by 50 MW over the 2004 plan to a total of 150 MW. Currently the Company includes 10 MW of geothermal generation in their portfolio as a result of the power purchase agreement with the Raft River geothermal project. See Case No. IPC-E-05-1. As previously noted, the Company is in the latter stages of the RFP evaluation process for a 50 MW geothermal project expected to be online in 2009.

What had been considered a 100 MW geothermal acquisition online in 2008 in the 2004 IRP has been altered to three separate 50 MW acquisitions in the 2006 plan including the aforementioned project. The other two projects are projected to be online in 2021 and 2022. The Company notes that heavy reliance on geothermal generation is risky at this time due to uncertainty in the availability of geothermal resources, but will reassess that position in the 2008 IRP should the results of the "RFP indicate that an abundant supply of cost-effective geothermal projects" exist in Idaho. IRP at 90.

The single 500 MW coal-fired generation resource from the 2004 preferred portfolio has been altered in the 2006 IRP to two 250 MW acquisitions dispersed over the planning horizon. From the previous IRP filing, the Commission ordered the Company to address new coal technologies when examining coal-fired resources. Order No. 29762. In response, Idaho Power and Avista jointly contracted with Cummins & Barnard, an engineering consulting firm, to assess the current state of coal based generation technologies. IRP, Technical App. D at 99-106. The preliminary results from that study show that IGCC technology with carbon sequestration and enhanced pulverized coal technologies may be a viable resource in the future. Currently there are two large-scale IGCC facilities in operation in the United States, but the large initial capital expenditure (estimated at over $2500/kW of total investment in 2006 dollars) and unproven technology remain the primary barriers for larger scale deployment. Future changes in carbon regulations, such as emissions taxes, along with technological advances may make IGCC technology, especially with carbon sequestration abilities, more economically competitive in the future.

The other 250 MW of coal-fired generation is anticipated to be online in 2013. Details regarding this acquisition are uncertain to date. The Company has provided a number of potential scenarios for adding regional pulverized coal to its resource portfolio with the expectation that any generating unit will be located outside of the State. By breaking up its acquisition of coal based resources into smaller units than that proposed in the 2004 IRP, the Company notes that this reduces its exposure to risk of equipment failure and coincides better with expected load growth. IRP at 97. Staff observes that this reduces the immediate rate impact on the Company's customers as well. Idaho Power has informed the Commission and Staff that it has executed a memorandum of understanding with Avista to explore the option of jointly developing a coal-fired facility. Seasonal or shared ownership, as well as expansion of existing generation facilities, are also options the Company is considering. The Company may also want to consider short-term interim participation in regional coal plants. It is anticipated that the Company will have a firmer grasp on its options early in 2007.

The remaining supply side resources in Idaho Power's preferred portfolio include 150 MW of Combined Heat and Power (CHP) and a 250 MW power purchase agreement (PPA) with INL for nuclear power. As stated earlier, the inclusion of the nuclear PPA is speculative at this time, but is not considered in the plan to be enacted until 2023. It is assumed that this will be addressed in future IRPs, along with nuclear power in general, and is not significant in the Company's near-term plan. The CHP addition identified in the preferred portfolio is anticipated to occur in two installments, with 50 MW predicted to be online in 2010 and an additional 100 MW in 2020. Quantifying the costs associated with CHP is difficult, as project costs are very site-specific. The Company has used cost figures from the 2004 IRP escalated at 3% for its 2006 analysis. Figures 5-1, 5-2, and 5-3 demonstrate that CHP is potentially an economically competitive generation resource. IRP at 46-48.

DSM Measures

The 2006 IRP sets more aggressive targets for DSM savings for the planning period than did the 2004 IRP. Staff supports prudently managed, cost effective DSM programs and hopes that the Company can reach at least the targets set out in the IRP.

The 2006 IRP proposes two new DSM programs and refinement and expansion of an existing program that will potentially result in a nearly 88 aMW savings and a reduction in peak load of 187 MW in 2025, both in addition to its existing programs. The new programs target existing residential and commercial customers with savings of 29 and 18 aMW and peak reductions of 113 and 27 MW, respectively, in 2025. The refined and expanded industrial program is projected to save 40 aMW and 47 peak MW in 2025. IRP at 65.

Idaho Power's existing DSM programs, which include new homes and commercial buildings as well as existing residential air conditioning, low-income customers and industrial and irrigation customers, resulted in an average savings of 4.7 aMW and peak hour reductions of 47.5 MW in 2005 according to IRP Table 2-6. IRP at 25. Staff notes that the 2005 DSM report submitted as Appendix B to the 2006 IRP lists a slightly lower 43.1 peak hour reduction, which excludes 4.5 MW attributed to energy efficiency programs and Northwest Energy Efficiency Alliance (NEEA) market transformation. Most of the existing programs are projected to expand for at least the first few years of the planning period, according to the 2004 IRP.

In Case No. IPC-E-06-22, the Commission approved modifications to the Irrigation Peak Rewards Program that are intended to expand the program beyond the level of the 2006 Program. See Order No. 30194. However, there is no acknowledgement of the program or assumptions of continued associated savings and reductions to be found in the 2006 IRP. If included, the Company needs to be more explicit in how it is factored into the analysis; if not included, the Company should explain why.

Underestimating DSM savings may lead to a heavier, unnecessary reliance upon supply side resources. Given that DSM efforts continue to show exceptional value with benefit/cost ratios as high as 4.3, the Company should continue to expand these programs and properly record energy savings. IRP, Technical App. D at 73. Prudent DSM management results in not only acquiring DSM as cost-effectively as practicable, but also acquiring all cost-effective DSM, and fully incorporating the savings into the IRP.

There are several factors that may influence the level of DSM implementation. One particular example worth noting is the implementation of a fixed cost adjustment mechanism designed to keep the Company financially neutral to deviations in sales, such as lost sales due to DSM efforts. See Case No. IPC-E-04-15. The goals of the fixed cost adjustment are to remove the inherent disincentive to investing in demand-side measures and facilitate the Company's efforts to expand its DSM offerings. Staff is interested in whether approval of the fixed cost adjustment mechanism would affect the analysis conducted for the IRP, and if so, how.

A second example is the status of the Company's advanced meter reading (AMR) deployment. In Order No. 30102, the Commission granted Idaho Power a one-year period to investigate the technical issues that plagued the AMR deployment in the Emmett area. Through meetings with the Staff, the Company has reported that many of the technical issues have been addressed, though new issues have appeared. Failure to resolve these issues may have a deleterious effect on demand response programs that utilize AMR technology. Staff and the Commission have been strong proponents of time variant pricing and other demand response programs, and hope that the technical issues can be resolved and full-scale deployment can be achieved as quickly as is prudent. The Company is scheduled to submit an updated status report by May 1, 2007.

Staff recognizes and supports the Company's effort to distribute its DSM efforts among customer classes, between new construction and existing customers, between direct incentive programs and NEEA's market transformation efforts, and between energy efficiency and peak load reductions.

DSM programs continue to be among the most cost effective resources available to Idaho Power as demonstrated in Figures 5-1, 5-2, and 5-3 of the 2006 IRP. IRP at 46-48. However, IRP Fig. 5-7 projects Idaho Power's DSM energy savings for 2007 and 2008 at between 65% and 75% of its proportional share of the Northwest Power and Conservation Council's (NWPCC) estimate of total conservation potential. IRP at 69. While the 2006 IRP demonstrates a higher commitment to

DSM efforts than in the past, the Company does not yet propose to pursue all cost-effective DSM opportunities and incorporate associated energy and peak demand savings into its determination of new supply side resource needs. Perhaps the Company's fixed cost adjustment proposal in Case No. IPC-E-04-15 and its DSM incentive proposal in Case No. IPC-E-06-32, will mitigate the Company's position stated in the IRP's Technical Appendix D that DSM programs will be selected to minimize negative impact on shareowners. IRP, Technical App. D at 62.

Risk Analysis

Idaho Power selected four of the twelve potential portfolios for further risk analysis in determining the preferred portfolio. Risk measures fall into either quantitative or qualitative categories. The quantitative analysis closely follows that of the 2004 IRP with two exceptions, the exclusion of risk analysis associated with the expiration of production tax credits for wind and the inclusion of a sensitivity analysis to variations in the streamflows of the Snake and Columbia River systems. Advancement in the modeling software facilitated simulating various streamflow sequences for the hydrologic variability analysis, which each portfolio analyzed under varying assumptions of load requirements, carbon taxes, etc. The resulting analysis was not used in the final risk adjustment due to the magnitude of the impact of varying hydrologic conditions. Staff finds this to be reasonable and notes that the difference in variability between the highest and lowest cost portfolios are relatively small ($404 million versus $434 million, or less than 7% difference in variability).

The quantitative factors used in the scoring of the finalist portfolios remained the same from the 2004 IRP (carbon taxes, natural gas price, capital and construction costs, and market risks), though the input values have changed in most categories. As mentioned before, the natural gas price forecasts have been updated since 2004, as well as the discount rates used in the capital risk analysis. The subjective probabilities associated with the low, expected, and high scenarios have remained at the 2004 levels in all risk analyses with the exception of capital cost risk, which changed from 10%, 80%, and 10% respectively to 10%, 60%, and 30% respectively. As noted in Staff comments from the 2004 IRP, the Company does not provide a basis for its probability assignments, which can have significant economic impacts on the portfolios under consideration. For example, the Company uses $14/ton as an expected case scenario for the carbon adder with 50% probability. Yet given the probability weighting assignments made by the Company, the expected value of the carbon adder is $17/ton.[1]

[1] Expected value in this case is the average of possible carbon adder values weighted by their probability. Specifically, Expected value = ($0*.3)+($14*.5)+($50*.2) = $17/ton.

For the preferred portfolio, this adds an additional $200 million to power supply costs. Because the composition of the portfolio dictates the impact of varying assumptions, these impacts are not equal across the board. The lowest cost portfolio, in comparison, has nearly a $50 million smaller impact due to this change.

Idaho Power has expanded its qualitative risk section in the 2006 IRP. In addition to regulatory risks (e.g. the imposition of renewable resource portfolio standards), resource timing and commitment risks, and operational concerns associated with its hydropower facilities, the Company acknowledges the risks associated with technologies, fuels, and the implementation of the preferred portfolio. Without specifically tying these qualitative measures to the individual portfolios, the Company expresses its concerns regarding these areas in general terms. Of the qualitative risks, it appears as if the more important risks that factor into the selection of the preferred portfolio are concerns over the operational risk of transmission projects (and market liquidity), technology, specifically with regards to IGCC, and potential renewable portfolio standards.

The methodology used in the analysis resulted in the selection of the preferred portfolio, an extension of the 2004 preferred portfolio that highlights a diverse mix of new resource acquisitions. The Company states that the diversified approach mitigates exposure to qualitative risks, and provides flexibility in planning should actual conditions deviate from those used in the planning criteria. IRP at 91. The preferred portfolio scored well in the risk analysis, ranking second behind the 'green portfolio'. Staff would note that the preferred portfolio had the second highest cost of the finalists in terms of average total cost, yet the lowest in terms of resource cost (capital and operating costs, with market sales and purchases excluded). The preferred portfolio was the second lowest risk-adjusted total cost portfolio among finalists due to its relatively higher risk ranking.

Near-term Action Plan

Since 2001, Idaho Power has been in a period of acquiring supply-side resources after nearly two decades of relatively few additions to its generation resource mix. The 2004 and 2006 IRPs have presented a need to meet future deficiencies in energy as well as peak loads. Given the long lead time associated with thermal baseload generation facilities and the projected persistent deficiencies in energy beginning in 2012, it is imperative that the Company begin addressing these concerns. The Company is currently investigating its options with regard to a coal-fired resource addition, as noted earlier. The near-term action plan shows 2007 as the target date for identifying, selecting and proceeding into the pre-construction phase of this endeavor.

The Borah-West transmission upgrade is scheduled for completion prior to the Company's next IRP filing in 2008. By that time it is anticipated that the final commitments for the McNary-Boise transmission upgrade will have been made. This addition is expected to be complete around 2012. Besides the Borah-West project, the Company is in the final stages of the wind RFP for 100 MW scheduled to be online by the end of 2007, as well as finalizing the geothermal RFP for 50 MW, scheduled for an online date in 2009. Finally, the approved 170 MW expansion of the Danskin facility is anticipated to be online in 2008. These additions, along with changing conditions faced by Idaho Power regarding loads, fuel prices, and market conditions will invariably affect the Company's 2008 IRP.

STAFF RECOMMENDATION

Staff recommends that the 2006 IRP be accepted and acknowledged as submitted.

Respectfully submitted this 22nd day of January 2007.

Cecelia A. Gassner
Deputy Attorney General

Technical Staff: Bryan Lanspery

i:umisc:comments/ipce06.24cgrps

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **22ND** DAY OF JANUARY 2007, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF**, IN CASE NO. IPC-E-06-24, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of Idaho Power Company's 2006 Integrated Resource Plan	Case No. IPC-E-06-24 **COMMENTS OF EXERGY ON IDAHO POWER'S 2006 INTEGRATED RESOURCE PLAN**

COMES NOW, Exergy Development Group of Idaho LLC ("Exergy"), and pursuant to this Commission's Notice of Filing and Notice of Comment Deadline in the above-captioned proceeding, submits these comments on Idaho Power's 2006 Integrated Resource Plan (IRP). For the reasons described below, the Commission should deny Idaho Power's application to the Commission to accept its 2006 IRP for filing.

I. The 2006 IRP overlooks important and obvious transmission improvements.

Idaho Power acknowledges in its 2006 IRP that its transmission system is a "key element" in fulfilling its responsibilities as a public utility.[1] It then, however, gives short shrift to consideration of how it should best maintain and expand its transmission system to meet its customers' needs. Idaho Power determines in its 2006 IRP to complete two transmission upgrades, totaling 285 MW, both of which are to the Pacific Northwest.[2] This determination is a disconnect from the big picture in which Idaho Power operates and foregoes obvious opportunities for the Company and its customers.

II. Idaho Power should not exclusively focus on transmission upgrades to the Northwest.

Resources in the Pacific Northwest, to which Idaho Power is seeking increased access, are predominantly hydroelectric generation. Likewise, Idaho Power's generation system is largely hydroelectric. Thus, in years when generation is abundant in the Pacific Northwest, it is also usually abundant on Idaho Power's system. This means that Idaho Power's transmission expansions in its 2006 IRP are wholly focused on accessing a market that is typically plentiful when Idaho Power does not need power, and deficit when it does.

Additionally, the Pacific Northwest hydro-system is becoming increasingly constrained due to operations for fish and wildlife mitigation, reducing surplus energy that is available for sale outside the region. Load growth in the region is also reducing surpluses, and causing utilities in the Pacific Northwest to look

[1] 2006 Integrated Resource Plan [*hereinafter* 2006 IRP], p. 20.
[2] 2006 IRP, p. 98.

elsewhere for energy needs. Any advantage Idaho Power may be seeking to gain from increased import capabilities from the Pacific Northwest, therefore, is dwindling. And, in any event, Idaho Power's exclusive focus on transmission upgrades to the Pacific Northwest does not represent a diversified or complementary strategy for resource acquisition.

III. Idaho Power should expand its transmission system to the east and south, where the resources are.

Idaho Power's determination to focus transmission expansion on access to the Pacific Northwest seems to be the result of improper constraints it put on its analysis in the 2006 IRP. Idaho Power explains that beginning with the 2000 IRP, it came to recognize that transmission constraints were limiting its options for purchased power supply strategies.[3] It then states that in order to "better assess power supply requirements and available transmission, the 2006 IRP contains an analysis of transmission system constraints for the 20-year planning period."[4] Unfortunately, Idaho Power's analysis "assumes all off-system market purchases will come from the Pacific Northwest."[5]

The Company's stated reason for assuming all off-system market purchases will be from the Pacific Northwest is that

> Many of the utilities to the east and south of Idaho Power also experience a summer peak, and weather conditions that drive the summer peak are often similar across the Intermountain and Rocky Mountain West. Idaho Power

[3] 2006 IRP, p. 36-37.
[4] 2006 IRP, p. 37.
[5] 2006 IRP, p. 32.

believes it would not be prudent to rely on imports from the Rocky Mountain Region for planning purposes.[6]

Exergy submits that this analysis is overly simplistic and that Idaho Power's conclusion ignores the obvious trend toward new resource development to the east and south of it. Coal from the Power River Basin in Montana and Wyoming is likely to be the source of significant amounts of new generation resources for the region, and northwest utilities are already looking there and to Utah coal plants for future power needs. Even Idaho Power's 2006 IRP specifically calls for 250 MW of new coal-fired generation, and an additional 250 MW of IGCC coal generation.[7] Idaho Power is extremely unlikely to find such new generation in the Pacific Northwest, and it is currently illegal to construct any coal-fired generation plants in Idaho. It therefore makes little sense for Idaho Power to overlook transmission to the east and south when common sense points that direction for new resources.

In addition to coal resources, a substantial amount of new renewable energy projects will be sited east of Idaho Power's service territory. The 2006 IRP acknowledges this, but acts as though transmission constraints associated with those new renewables will be addressed by a planned Borah-West transmission path upgrade, scheduled for May 2007.[8] This conclusion flies in the face of Idaho Power's recent dealings with renewable energy developers, where it argues that they should finance approximately $60 million of transmission upgrades it

[6] 2006 IRP, p. 32-33.
[7] 2006 IRP, p. 5.
[8] 2006 IRP, p. 99.

contends must be completed in order to integrate renewable power onto its grid and transport it to the Boise load center.[9] Exergy believes that what Idaho Power's position really shows is that the obvious place for Idaho Power to focus transmission expansion efforts would be toward the east and south, and that its current system is inadequate to incorporate new desirable resources.

Idaho Power's finding that many of the utilities to the east and south of it experience similar summer peaks does not favor a decision to ignore transmission expansion in that direction. As stated above, considerable resources exist and are expected in that region. The fact that other utilities will also be relying on those resources does not justify Idaho Power's disregarding them. In short, Idaho Power, like other utilities, must seek resources where they are located. Additionally, Idaho Power's disregard of access to resources to the east and south in favor of resources in the Pacific Northwest is troubling in light of its recognition in the 2006 IRP that "[r]ecent history has shown even when power is available from the Pacific Northwest market, short-term prices can be quite high and volatile."[10] It is also difficult to square Idaho Power's transmission conclusions with its recent statement to this Commission regarding its 2004 IRP that "[t]he

[9] *See generally*, Complaint of Cassia Gulch Wind Park LLC, Answer and Comments of Idaho Power, and Comments of Exergy, on file with this Commission in Case No. IPC-E-06-21 (addressing dispute between Cassia Wind and Idaho Power arising from Idaho Power's proposal to assign $60 million of transmission upgrades to renewable energy project developers).
[10] 2006 IRP, p. 36.

existing transmission system between Idaho Power and the Pacific Northwest has been largely optimized."[11]

Other entities are endeavoring to construct transmission to the east and south of Idaho Power in order to gain access to the very resources Idaho Power should be seeking. For example, the Arizona Public Service Company is exploring the feasibility of constructing two new 500 kV transmission lines from the Power River Basin and adjacent wind resources to northern Arizona, through Utah, in order to access over 6000 MW of coal and wind resources there.[12] Again, it makes little sense for Idaho Power to overlook access to these resources as it thinks through how it will serve its loads over the next twenty years. Given that transmission projects require "considerable lead times,"[13] Idaho Power should not put off transmission expansions which will undoubtedly prove needful in the future.

IV. The Commission should not accept Idaho Power's 2006 IRP, and should send it back to the Company to reconsider.

This Commission demands that a utility's filed IRP contain a "reasonable assessment of supply and demand side opportunities available to the Company."[14] The analysis and conclusions offered in the 2006 IRP with regard to transmission expansion, however, are not reasonable or well-considered. Without good reason,

[11] Response of Idaho Power Company to Filed Comments on its 2004 IRP, p. 8, filed in Case No. IPC-E-04-18.
[12] *See* APS Study Plan, TransWest Express Project, Phase 1—Feasibility Study, *available at* http://www.oatioasis.com/AZPS/AZPSdocs/TransWestExpressProject-FS_Plan_7.pdf.
[13] 2006 IRP, p. 63.
[14] Order No. 29189, p. 20, Case No. IPC-E-02-8 (February 11, 2003).

Idaho Power fails to fully consider transmission options that would open a wealth of resource opportunities. Instead, the Company disregards transmission expansion opportunities to the east and south, and focuses myopically on upgrades to the Pacific Northwest, where resources do not complement Idaho Power's existing system, and where any advantages are likely fading.

For all the reasons stated above, the Commission should deny Idaho Power's application to accept for filing its 2006 IRP, and should require the Company to reconsider its analysis and conclusions.

Respectfully submitted this 19th day of January 2007.

Peter O. Richardson

Peter Richardson ISB # 3095

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the forgoing Comments of Exergy in Docket No. IPC-E-06-24 were mailed via U.S. Mail postage prepaid on January 19, 2007 to:

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IDAHO PUBLIC UTILITIES COMMISSION

Comments of the NW Energy Coalition
Idaho Power Company's 2006 Integrated Resource Plan

January 22, 2007

The NW Energy Coalition appreciates the opportunity to provide these comments to the Idaho Public Utilities Commission relating to Idaho Power Company's 2006 Integrated Resource Plan in Case No. IPC-E-06-24.

The NW Energy Coalition (Coalition) was pleased to have had the opportunity to participate at the invitation of Idaho Power Company (the Company) in the 2005 and 2006 meetings of its Integrated Resource Plan Advisory Council (IRPAC). The Coalition is not a member of the IRPAC (although its interests are represented by IRPAC members Advocates for the West and the Natural Resources Defense Council), but extends its appreciation to the Company for including it in IRPAC meetings and for receiving Coalition views and comments as the Company prepared the 2006 IRP.

As we articulated in comments to the Commission on the 2004 IRP, the Coalition believes the IRPAC process is an excellent means of ensuring that all stakeholder constituencies have an opportunity to contribute to IRP development at virtually all stages of the process. More importantly, we believe the Company seriously evaluates and responds to the IRPAC's input, and that the IRP document is a better final product because of that commitment.

The NW Energy Coalition is a non-profit regional alliance of more than 100 diverse environmental, civic, consumer, low-income customer advocacy groups, energy efficiency and renewable energy businesses, and progressive utilities in Idaho, Montana, Washington and Oregon. The Coalition's main address is: 219 First Ave South, Suite 100, Seattle, WA 98104. Its Idaho address is 5400 W. Franklin, Suite G, Boise, ID 83705. In Idaho, the Coalition has numerous individual and organizational members, including Idaho Rivers United, Idaho Conservation League, Snake River Alliance, Idaho Rural Council, and the Community Action Partnerships in Idaho. Members of the Coalition and its Idaho member organizations include customers of Idaho Power Company.

The Coalition advocates for increased energy conservation efforts, sustainable and ecologically sound management of electric generating infrastructure, increased integration of renewable sources of energy in utility portfolios, and appropriate rate design policies consistent with these goals, all of which ensure low-cost and sustainable power and rate stability for all utility customers.

Introductory Comments on Preferred Portfolio

The Company's preferred portfolio continues a number of encouraging trends, notably long-awaited increases in demand-side resources as the Company's conservation and efficiency programs develop and gain traction. To its credit, the Company is heeding Commission advice in the 2004 IRP proceedings to expand more aggressively its DSM programs. As discussed more fully below, we have expressed concern in the past about the size of the Company's rider-funded DSM balance and share the Company's optimism that this excessive balance will be drawn down this year and that the Company will return to the Commission with a renewed request to increase its DSM tariff rider.

We continue to be concerned about the amount of thermal resources proposed for acquisition in the preferred portfolio. While we agree that a planned acquisition of IGCC coal is preferable over conventional coal, we remain unconvinced the addition of 500MW of coal is neither necessary nor prudent, particularly given the modest amount of wind acquisition proposed in this IRP. In addition, it is not prudent to invest in the additional cost of IGCC without achieving the benefits of sequestering the CO_2. Realizing that the Company is soon to begin construction of yet one more natural gas peaking plant in the Mountain Home area, we were pleased to note that the Company has heeded Commission advice in the 2004 IRP process to take a harder look at gas peaking plants. None are required in the planning horizon in this IRP, and none are included in the preferred portfolio.

<u>Supply-Side Resources</u>

While we are relieved that the proposed acquisition of conventional coal in the 2004 IRP has been deferred, we remain unconvinced of the necessity to include 500MW of coal-fired generation in this IRP at all. In fact, we agree with the Northwest Power and Conservation Council's Fifth Power Plan, which projected the entire region may need only a single coal plant very late in the Plan's horizon—and only if its forecast of achievable wind turned out overly-optimistic. However, the Council recently reported that the region's wind resources are increasing faster than expected, while loads are a bit slower. Both these results put the need for *any* coal plants at question.

The Company proposes a 250MW conventional Wyoming pulverized coal plant in 2013 and a 250MW regional IGCC plant in 2017. Both would likely be shared, seasonal ownership. The Company has been in negotiations with Avista Utilities for one of the coal plants; we presume the IGCC plant would be an expansion of the partnership with PacifiCorp and likely at the Bridger complex.

Recent events have reduced the likelihood of these plants being built – certainly of any unsequestered plant. The Oregon Public Utilities Commission on Jan. 16 made it clear it was not convinced that PacifiCorp had justified the need for two new coal plants (including one that may be part of a partnership with Idaho Power). The state of Washington last fall passed a Renewables Portfolio Standard (RPS), and the state of Oregon may well enact an RPS this year. The state of California will not allow its utilities to import energy with a carbon footprint heavier than that of a modern CCCT. As a consequence, the market in this region for surplus coal-fired energy continues to shrink as the states and the nation move forward with measures to reduce carbon emissions. We believe that adding 500MW in what is expected to be a carbon-constrained environment in the timeframe in this IRP's preferred portfolio amounts to a financial and environmental risk to ratepayers.

The Company proposes a 250MW conventional Wyoming pulverized coal plant in 2013 and a 250MW regional IGCC plant in 2017. Both would likely be shared, seasonal ownership. The Company has been in a joint exploratory effort with Avista Utilities for one of the coal plants; we presume the IGCC plant would be an expansion of the partnership with PacifiCorp and likely at the Bridger complex.

Recent events have reduced the likelihood of these plants being built – certainly of any unsequestered plant. The Oregon Public Utilities Commission on Jan. 16 made it clear it was not convinced that PacifiCorp had justified the need for two new coal plants (including one that may be part of a partnership with Idaho Power). The state of Washington last fall passed a Renewables Portfolio Standard (RPS), and the state of Oregon may well enact an RPS this year. The state of California will not allow its utilities to import energy with a carbon footprint heavier than that of a modern CCCT. As a consequence, the market in this region for surplus coal-fired energy continues to shrink as the states and the nation move forward with measures to reduce carbon emissions.

The projected emissions adder for thermal resources in this portfolio should be elevated to reflect a figure higher than the anticipated $14 per ton carbon adder, and quite likely should be accelerated to a date earlier than 2012. We realize that the $14 figure represents the expected case (50 percent) probability of imposition of the CO2 adder. However, a more realistic expectation is higher – perhaps much higher - than $14, while likely below the high-case $50 per ton. Raising the $14 adder will of course place many of the renewable resources analyzed in the IRP in a more favorable position relative to thermal resources. It would also assign a more realistic risk to the thermal resources in this portfolio.

Overall, we believe the Commission and Company should adopt a cautionary approach with respect to new pulverized coal. Pulverized coal presents cost, market, and environmental risks that are unnecessary for customers and shareholders to bear. We believe a strategy of fully realizing the potential for renewable energy development and DSM over the short term presents the least risk strategy to bridge over the coming years of uncertainty related to carbon regulation and climate change.

The preferred portfolio also anticipates expiration of the production tax credit for wind at 2012 – the same year the company estimates the carbon adder will take effect. This likewise may be a pessimistic view of the future of the PTC and the appetite to extend the PTC beyond 2012. Should it be extended (and we believe it will), wind once again assumes a more favorable standing relative to other resources.

Wind variability and amount of wind in the preferred portfolio

The anticipated risk associated with wind variability continues to be overstated at the expense of its proportionate share of the new resource acquisition. In addition, a more comprehensive examination of the value of geographic diversity of future wind resource acquisition would likely reduce the risk this IRP currently attaches to wind. And as mentioned above, the Company is likely overstating the likelihood of the PTC expiring in 2012.

The amount of RFP-scale wind included in this portfolio continues to lack the level of ambition and creativity we see elsewhere in the region. Realizing the company's existing situation with regard to PURPA wind contracts and the amount of PURPA wind currently scheduled for inclusion into the resource portfolio, restricting the level of RFP wind to 150MW (and the soon-to-be-approved 100MW from Horizon Wind from the 2006 RFP) is unwarranted. The Idaho Energy Division estimates that, in Idaho, we have 208MW of approved wind PSAs, 4,716MW of wind projects in various stages of development, and 591MW of wind projects in advanced planning stages. Even if 50 percent of these projects are fully developed, this energy will need a home – preferably in Idaho. Therefore, we view the Company's planned wind acquisition as disappointing and as unambitious.

Progress in wind forecasting and the advantages of region-wide geographic wind distribution can go a long way to ameliorate the company's variability concerns. We welcomed the provision in the Company's pending Power Purchase Agreement (PPA) with Telocaset Wind Power/Horizon ((IPC-E-06-31) that commit Telocaset to provide the Company with detailed, real-time wind forecasting data, and as mentioned in our comments to the Commission in that docket, we hope such a provision sets a precedent in future wind PPAs. Doing so can only improve the cumulative reliability of wind resources in the Company's portfolio and allow for greater amounts of wind energy to replace the ill-advised thermal resources in this portfolio.

The company should be encouraged to treat wind as a region-wide resource and to incorporate the diverse generation profiles from such far-flung resources as Horizon and the Columbia Gorge; southern Idaho; and the firmed Montana wind resources. With adequate transmission resources, particularly in Southern Idaho, there is more than adequate room on the Company's system for a great deal more wind than the modest 150MW projected for 2012.

Non-wind renewables

As mentioned above, we believe the preferred portfolio should include significantly more wind. However, it also calls for a disappointingly low level of non-wind renewables in the company's total resource stack.

The company acknowledges on P.97 of the IRP that "Wind, geothermal, and other non-hydro renewable resources supplied a negligible amount of energy used by Idaho Power customers in 2005. Other than power purchased from several small PURPA projects and green tags acquired to support the Green Energy Program, Idaho Power had no major non-hydro renewable energy purchases in 2005."

The company then states in subsequent passages that it "anticipates acquiring a greater amount of non-hydro renewable energy given the number of PURPA resources either under contract or in contract negotiations." The draft then delivers this disappointing projection: "The preferred portfolio includes approximately 250MW of wind generation and 150MW of geothermal generation by 2025." (P98).

Other portfolios considered by the Company included far greater amounts of geothermal potential. We would hope that the Commission will direct the Company to revisit this too-modest projection of geothermal resources in future IRPs and adjust accordingly. Adding another 200 to 250MW of geothermal, which we believe is warranted, could well relieve the Company and its ratepayers of the need for the next coal-fired generation acquisition.

The Company expects that, including existing PURPA contracts and the projected 400MW of proposed renewable resources in the preferred portfolio, renewables will account for only 8.4 percent of Idaho Power's total generation portfolio by 2025.[1] While that is a notable improvement over the current renewables share in the Company's overall portfolio, 8.4 percent renewables in a total portfolio by 2025, even assuming unanticipated PURPA resources that could move that number higher, can be improved.

Nuclear

It's difficult to gauge the seriousness of its inclusion of 250MW of nuclear energy from the Idaho National Laboratory. From all appearances, the nuclear component appears to be an energy resource of convenience. We realize nuclear is only included based on the advice of the U.S. Department of Energy and the possible development of an experimental plant at DOE's INL It would be prudent to attempt to better calculate a more realistic risk profile of this resource so that it more realistically stacks with other resources.

The IRP's projected cost of nuclear energy is underestimated. It does not appear to include an emission adder, nor does it adequately address unresolved waste issues. When these and other externalities are included in calculating nuclear's true cost, the resource would become prohibitively expensive.

<u>Demand-Side Resources</u>

The IRP's anticipated 187MW in peak DSM is a welcome increase from past IRPs, but could be enhanced to achieve greater savings – particularly given the expected successful

[1] Calculated on an energy basis, using a 35% capacity factor for wind.

resolution of the pending decoupling docket before the IPUC.[2] But we continue to harbor concerns that even this level of savings is not sufficiently ambitious. While the Company's primary concerns in meeting projected load growth are in peak demand, we encourage the Commission to continue to emphasize the need for the Company to more swiftly integrate the additional DSM programs identified in the 2006 IRP.

We have raised concerns to the EEAG about the size of the current rider-funded DSM account balance, and have been assured by the Company that this balance is expected to be drawn down significantly during 2007 as existing DSM programs are expanded and new ones come on line. We agree with the Company that, as the DSM balance is reduced this year, the Company will anticipate the proper timing to return to the Commission with a request for an additional incremental rider increase to help the Company edge closer to meet conservation targets set by the Northwest Power and Conservation Council in its Fifth Power Plan.

One additional way to accelerate development of the Company's DSM programs would be to examine the company's projected customer growth of 9,000-10,000 customers annually (P. 69) and to require or incentivize those new customers to participate in such DSM programs as the Company's AC Cool Credit program or to require or incentivize solar or other renewable energy hook-ups as part of their new service. This projected growth in the Company's customer base would appear to provide Idaho Power with great leverage in promoting its DSM and efficiency programs.

Transmission

The Company's IRP includes 285MW of transmission upgrades (225MW in 2012 with the McNary-Boise upgrade and 60MW in 2019 with the Lolo-Oxbow upgrade). The addition of expanded transmission is welcome, and should provide the Company increased access to renewable resources and markets in the Northwest. We're concerned, however, that the company did not include in its preferred portfolio additional improvements in Southern Idaho transmission.

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Eastern and Southern Idaho will soon be home to significant wind generation that will require access to the Company's load centers. In addition, any plans to expand thermal generation at Bridger will similarly require improved east-west transmission. Realizing the Company expects to complete the Borah-West transmission upgrade in 2007, we are nonetheless concerned that transmission upgrades in the southern part of the state are adequate.

The Company's plans to upgrade the McNary-Boise transmission to better access Mid-C markets for purchases and surplus sales is commendable. However, Portfolio F4 (formerly Portfolio 11, or the Bridger to Boise Transmission portfolio) held promise in

2 As well as the recently approved Load Growth Adjustment in the PCA proceeding that will tend to put much more of the cost and risks of load growth on the Company.

that it included the 900MW transmission line from Bridger to Boise. The company properly notes that a Bridger-Boise line "Will provide the capability to integrate additional generation from the Jim Bridger Project, and additional wind and geothermal resources..."

We agree. It's regrettable that this potential asset, particularly its ability to transport the substantial wind resources in southern Idaho, is not included in the preferred portfolio. We recognize transmission remains a concern for the company as well as the IPUC and the region at-large. We disagree that Portfolio F4 "May place an undue reliance on the Wyoming energy market," particularly given the possibility that future thermal acquisitions (250MW of coal in 2013 from either an Avista partnership or from Wyoming, likely Bridger) and also the 250MW of possible IGCC coal, perhaps a Bridger expansion) will create demands on the company's southern Idaho transmission. The value of Bridger-Boise cannot be understated for its ability to bring the wind resources likely to be developed in the south to the load centers in southwest Idaho.

<u>Company's Request for Comment on Public Policy Issues</u>

The 2006 IRP contains five "public policy issues" on which the Company seeks public input. These issues include: The treatment of environmental attributes or Green Tags; emission offsets; financial disincentives for DSM Programs; IGCC technology risk; and asset ownership. We are not addressing each of these issues, but would like to comment on the following:

Green Tags

The Company asks several policy questions regarding the disposition of environmental attributes, or green tags. We agree that the Company must position itself for inevitable requirements of a future imposition of a national or state RPS. We believe Idaho Power must possess green tags in order to truly represent the renewable components of its generation portfolio. We realize the Company is currently wrestling with treatment of these green attributes, and we share the Company's concerns that it wants to avoid "double counting" these attributes. Green-e has established standards for treatment of these attributes, and we're pleased that the Company is looking to Green-e for guidance. If the Company plans to obtain green tags to satisfy its anticipated obligations, it may want to include provisions in future RFPs that bidders include tags as part of the product and pricing, but the tags should not be delivered to the Company unless provisions to do so have been included in a PPA.

Emission offsets:

As mentioned above, we do not believe the $14 per ton cost of the CO2 emission adder used in the IRP analysis is sufficient. A much higher figure would better reflect both the risk of thermal energy acquisitions in this IRP as well as more accurately rank the various resources considered. It is evident from the analysis that a $14 per ton adder still resulted in unsequestered coal resources being included in the Company's portfolio. We cannot imagine that if the state or federal government imposes a carbon restriction it would choose a penalty level that did not change utility behavior. Thus, such an amount is inadequate for analysis of a future that requires carbon controls.

The question posed by the Company, however, deals with whether it should "investigate purchasing options to acquire future carbon offsets," which "could potentially reduce the large financial exposure of possible carbon taxes for the cost of the option premium." The Company also believes it should be able to recover such purchases as well as the cost of any emission offsets.

In selecting resources with carbon implications, the Company is assuming significant risk. That risk should not be borne by ratepayers who disagree with the resource selection, and that risk should also be elevated to reflect the true probability of the emission adder's imposition and its implications for ratepayers and shareholders. It seems absurd to allow the Company to choose high-carbon resources at ratepayer expense (and risk) and then also charge ratepayers for the cost of offsetting the emissions from those choices. In addition, we are not convinced that purchasing offsets today will, as the Company asks, meet future carbon control requirements and regulations. IRPAC members discussed this issue at length, and there were sharp disagreements as to whether such purchases are prudent, and also whether purchasing "options" were prudent and whether they would have value once the CO2 adders arrive.

IGCC technology risk:
Integrated Gasification Combined Cycle coal generation technologies are far from mature, which is why the Company placed acquisition of this 250MW supply-side thermal resource in 2017, deep into this IRP's horizon and after development of a conventional coal resource.

Of course, if the Company eliminated both of its proposed coal generation proposals in this IRP, as the Coalition recommends, this policy question would be moot. The Coalition opposes acquisition of *any* coal generation resource in the Northwest, the lone exception being an IGCC plant that includes full carbon capture and sequestration and only then if all other options have been exhausted.

We appreciate and understand the Company's interest in exploring the cleanest possible thermal generation options, and also in deferring acquisition of even an IGCC plant until the Company can assure it meets the above requirements. The preferred portfolio envisions a partnership in a pulverized coal plant to come online in 2013 and a partnership for an IGCC plant to come online in 2017. One of the Company's policy questions is whether, if a near-term opportunity arises that would allow it to participate in an IGCC partnership, the Company should take advantage of it. Pending fruition of a viable IGCC partnership within the timeframe covered by this IRP, we cannot support inclusion of coal-fired generation of any sort being included in this IRP.

Conclusion

Idaho Power's 2006 IRP has much to commend it, notably its increased levels of DSM, its attention to transmission concerns previously expressed by the Commission in acknowledging the 2004 IRP, and the absence of yet more natural gas peaking generation. We would hope that the Commission would agree with our concerns about the projected level of renewable energy, particularly wind, in this IRP, and we do not believe an adequate case has been made for the two coal acquisitions – certainly the near-term pulverized coal proposal.

We reiterate our belief, as stated at the outset, that the Company's IRPAC process and the Company's willingness to consider diverse views from the Advisory Council continue to improve the final product, and we commend the Company's efforts to reach out to its ratepayer and other constituent stakeholders.

Respectfully submitted,

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2006 INTEGRATED RESOURCE PLAN	)	**CASE NO. IPC-E-06-24**
	)	**COMMENTS OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER**

I. INTRODUCTION

The Industrial Customers of Idaho Power (ICIP) appreciate the opportunity to offer comments on Idaho Power's 2006 Integrated Resource Plan (IRP), filed with the Commission on September 24, 2006. ICIP also appreciates Idaho Power's efforts to develop its IRPs with the assistance of the IRP Advisory Council, to which some of ICIP's individual members belong. These comments are intended to offer ICIP's views of the 2006 IRP after having a chance to review the final product in whole, and to assist the Company in its resource planning as well as the Commission in determining whether it should approve the 2006 IRP for filing. For all of the reasons below, ICIP believes that the Commission should not accept the 2006 IRP for filing at this time, but should instead require Idaho Power to reconsider and supplement the 2006 IRP as explained herein.

The Commission has explained that an IRP must include both supply- and demand-side options available to the Company in meeting its loads in a cost-effective manner.[1] Also, it has held that the "IRP should not be regarded by Idaho Power as simply an academic or regulatory exercise."[2] It should be regarded as an "actual planning document of the Company" and it should accurately represent its "best estimate of future changes in loads, resources and contract obligations."[3] The 2006 IRP does not achieve those standards, and contains certain inaccuracies and incomplete considerations of various important issues.

II. THE 2006 IRP FAILS TO OFFER A COMPREHENSIVE EVALUATION OF THE VARIOUS RESOURCE ALTERNATIVES AVAILABLE TO IDAHO POWER

a. *The 2006 IRP Did Not Evaluate Resources Under Consideration by the Company and Commission*

Although ICIP does not believe it is appropriate in this proceeding to reiterate its opposition to the Company's recently approved Evander Andrews natural gas-fired combustion turbine, the process through which that plant was chosen and approved raised concerns with ICIP that are relevant to the company's IRP. Idaho Power's application in the Evander Andrews proceeding relied almost exclusively on the 2004 IRP, which called for an 88 MW peaking resource.[4] By the time that application was considered by the Commission, the Company had already released its 2006 IRP, which contained drastically different assumptions regarding, among other things, natural gas prices and Demand-Side Management (DSM) program levels. In ICIP's view, these changes called into serious question the advisability of constructing a natural gas combustion turbine. And, unfortunately, the 2006 IRP simply assumed that the Evander Andrews plant would be built, and contained no analysis of whether it in fact should still be pursued. This left

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[1] Order No. 29189, Case No. IPC-E-02-8, at 20 (Feb. 11, 2003).
[2] *Id.*
[3] *Id.*
[4] *See* Application of Idaho Power, filed in Case No. IPC-E-06-09 (April 14, 2006).

the task of showing whether the Evander Andrews project was appropriate under current conditions up to ICIP and Commission staff, without any supporting analysis from the company based on current data.

In light of the purpose of an IRP to accurately evaluate the various resource choices available to Idaho Power, ICIP urges the Commission to require the Company, in future IRPs, to evaluate any resources under consideration in order to determine if they continue to be preferred options. Allowing the company to bootstrap old resource decisions into new planning processes leaves open the possibility that imprudent resources will be constructed due simply to the inertia of the process that initiated them. Until a project is constructed, it should never be too late to reevaluate the wisdom of pursuing it to completion.

b. *The 2006 IRP Does Not Evaluate A Resource the Commission Has Now Ordered it to Investigate and Implement*

As explained by ICIP in the Evander Andrews application proceeding, Idaho Power has previously committed to investigate the potential of using distributed generation, in the form of emergency backup generators installed throughout its service territory, as a potential resource for meeting its peak demand.[5] Idaho Power has not followed through on that commitment, and this Commission accordingly entered the following order in that case:

> Idaho Power shall investigate and develop a proposal for the implementation of a "virtual peaking plant" program based upon the use of customers' emergency generator resources located throughout the Company s service area. This proposal shall be submitted to the Commission for its review no later than June 1, 2007.[6]

[5] *See* Oregon Public Utilities Commission Order No. 05-871, p. 15 (July 28, 2005).
[6] Order 30201, p. 18, Case No. IPC-E-06-09 (Dec. 15, 2006).

Idaho Power's 2006 IRP does not offer any consideration of the potential peaking resource that could be gained through a "virtual peaking plant." Because the Company is currently engaged in evaluating this resource, and because it will have a proposal for the implementation of such a plant by June 1, 2007, ICIP believes that the Commission should direct Idaho Power to include in its 2006 IRP its findings, and the impact that such a plant will have on its resource decisions. Without such a supplement to the 2006 IRP, it will not contain a reasonably accurate resource picture upon which Idaho Power can base resource decisions.

III. THE 2006 IRP DOES NOT CONTAIN IDAHO POWER'S BEST LOAD FORECAST

As described above, Idaho Power's 2006 IRP should contain its "best estimate of future changes in loads, resources and contract obligations."[7] However, Idaho Power is aware of significant changes in its load forecast that it did not include in its 2006 IRP.

In May of 2006, a significant increase in Idaho's Conservation Reserve Enhancement Program (CREP) was announced. Under the CREP program, significant amounts of farmland is set aside, and irrigation pumps are accordingly turned off. Although water conservation is a main purpose of CREP, it has a significant impact on Idaho Power's loads, and especially its peak demands, which are substantially driven by irrigation pumping loads.[8]

In a recent forecast of Idaho Power's loads, Idaho Power has incorporated an annual energy reduction over the next 15 years (2007 through 2021) of approximately 4%

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[7] *Id.*

[8] *See Direct Testimony of Don Reading on Behalf of ICIP*, filed in Case No. IPC-E-06-09, p. 33 (non-Confidential version).

because of CREP.[9] However, Idaho Power has stated that "[f]or planning purposes, Idaho Power has not incorporated any specific assumptions in the 2006 IRP regarding the . . . CREP."[10] The effects of that reduction could be significant in Idaho Power's preferred portfolio in the 2006 IRP, especially given the dual impact to energy and peak demand. The Commission stated a concern on this topic in its order accepting the company's 2004 IRP for filing. It cautioned, "the continued effects of the drought on irrigation pumping and other *state actions that reduce the amount of irrigation pumping creates uncertainty* regarding the need for additional peaking resources."[11] The Commission should direct Idaho Power to incorporate this new forecast into its 2006 IRP analysis in order to ensure that it provides a complete evaluation of the resource options available to it, based on accurate data.

IV. THE 2006 IRP'S ANALYSIS OF TRANSMISSION IMPROVEMENTS DOES NOT TAKE INTO ACCOUNT IMPORTANT RESOURCES AND MARKETS EAST OF IDAHO POWER'S SERVICE TERRITORY

In its 2006 IRP, Idaho Power elects to pursue two transmission upgrades. Both upgrades are intended to expand its access to the power market in the Pacific Northwest.[12] Although relatively inexpensive hydropower exists in the northwest, ICIP is concerned that the 2006 IRP does not fully consider options for upgrading Idaho Power's transmission system to increase access to markets and resources located east of its service territory.

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[9] *See id.* (citing Exhibit No. 234, Response to ICIP Request for Production No. 41).
[10] *Id.*
[11] Order No. 29762, Case No. IPC-E-04-18, p. 10 (emphasis added).
[12] 2006 IRP, p. 98.

The Pacific Northwest hydrosystem has become increasingly constrained due to operations for compliance with the Endangered Species Act and other fish and wildlife mitigation measures. Additionally, growing loads in the Pacific Northwest are expected to consume an increasing proportion of the low-cost hydropower available there. Given these changes, ICIP questions the prudence of Idaho Power's assumption in its 2006 IRP that "all off-system market purchases will come from the Pacific Northwest."[13] ICIP expects that coal resources located in the Power River Basin will likely be the source of low-cost generation resources for the region. Idaho Power's call for 500 MW of new coal-fired generation[14] tends to support a closer look at transmission expansion options to the east of its system, where such resources are more likely to be located than in the Pacific Northwest or Idaho.

V. THE IRP DOES NOT ADDRESS THE EFFECTS OF RATE DESIGN ON LOAD

Again, Idaho Power's IRP should contain an accurate and complete evaluation of the resources available to it, based on its most accurate data concerning loads, resources, and contracts. In order to do this, ICIP believes that the 2006 IRP should contain an evaluation of the effects that various rate designs will have on Idaho Power's loads. For example, time-of-use metering could have a significant effect on Idaho Power customers' usage. ICIP is not certain that the 2006 IRP evaluates the effects that such programs could have on Idaho Power's load forecast or resource decisions. The Commission

[13] 2006 IRP, p. 32.
[14] 2006 IRP, p. 5. Half of the coal-fired generation contemplated in the 2006 IRP is Integrated Gasification Combined Cycle (IGCC) clean coal technology.

should direct Idaho Power to clarify how its IRP accounts for such tools, or direct it to supplement the 2006 IRP with relevant data.

VI. THE COMMISSION SHOULD REQUIRE IDAHO POWER TO SUPPLEMENT ITS 2006 IRP WITH NECESSARY INFORMATION

For all the reasons stated above, ICIP urges the Commission to deny Idaho Power's application to have the Commission accept its 2006 IRP for filing at this time. The Commission should instead direct the company to reconsider and revise its 2006 IRP to fully address 1) the resource potential of a virtual peaking plant in Idaho Power's service territory, 2) changes in load due to the CREP program, 3) whether its transmission upgrade decisions should not be revised, and 4) the effects of rate design on its load forecasts and resource decisions. Additionally, the Commission should direct the company to fully consider in future IRPs the prudence of any resources that are under consideration for construction at the time, even if called for in a prior IRP.

Respectfully submitted this 19th day of January, 2007.

Peter Richardson

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the above Comments of the Industrial Customers of Idaho Power in Docket No. IPC-E-06-24 was mailed via U.S. Mail, postage prepaid, on January 19, 2007 to:

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IDAHO PUBLIC UTILITIES COMMISSION

January 19, 2007

IPC-E-06-24

Commissioner Marsha Smith
Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Idaho Power Company Integrated Resource Plan 2006

Dear Commissioner Smith:

I am submitting the following comments relating to Idaho Power Company's 2006 Integrated Resource Plan, the "Energy Plan for Tomorrow", on behalf Idaho Irrigation Pumpers Association, Inc. IIPA's stated goals are to ensure that Idaho's irrigators have access to an inexpensive, reliable electrical power supply. In recent years, IIPA has also become interested in opportunities for irrigators to participate in the development of various resource options including demand-side management and the production of renewables to the benefit of the utility, its ratepayers, and individual irrigators.

IIPA would like to commend Idaho Power first for its thorough examination of the various alternatives available to the company, its shareholders and its ratepayers in developing this particular IRP. It is our opinion that the IRP appears to be realistic and practical in its approach to maintaining future reliability. Our association followed the development of this plan from its inception and would like to express its appreciation to Idaho Power Company for providing the opportunity for an IIPA representative to participate on the IRP Advisory Committee.

The company is also to be commended for proposing a diverse resource base ranging from existing hydropower to renewables and conservation, demand-side management programs and potentially nuclear. Because Idaho is a net importer of energy, it is important to at least consider every viable resource option available. A diverse resource portfolio is important not only to meet reliability, but to maintain rate stability.

IIPA supports Idaho Power Company in its efforts to preserve and protect its hydropower base, especially the Hells Canyon Complex. It is a significant factor in keeping the company's overall rates among the lowest in the region and nation. We agree with the IPCO's assessment that failing to re-license existing hydropower projects, allowing restrictions to be placed on those licenses that decreases available capacity or increases operational costs would be detrimental to the company and its ratepayers.

IIPA also supports the company's assessment that it must build base load capacity to address the phenomenal growth it is currently experiencing whether that occurs in or out-of-state. In the current regulatory climate, it appears doubtful that Idaho Power will be able to add thermal generation in state so IIPA urges the company to follow through with its proposal to upgrade and expand its present transmission system.

However, IIPA would like to stress the fact that, while company growth is driving its need for additional resources, irrigation load is not increasing. The estimated 10 to 12,000 customers per year that Idaho Power projects it will add during this planning period, are not irrigation customers. The IRP estimates the cost of adding services for each new residential customer at approximately $5,500, a cost that should be born by those customer classes. The irrigation customer class is not adding to the overall cost of service that the company is experiencing as it builds to meet new growth. Growth in other customer classes should not unfairly burden the irrigation class as a whole.

IIPA supports Idaho Power Company's proposal to add 187 MW of demand-side management and is hopeful that the irrigation customer class will be able to continue contributing substantially toward that goal. Over the last several years IIPA has worked with Idaho Power to design both its Irrigation Peak Rewards Program and its Irrigation Efficiency Program. In 2006 the Peak Rewards Program reduced coincident peak load by approximately 40 MW, roughly the equivalent of building a small generation facility.

IIPA urges the company to continue its efforts to develop demand-side management programs for irrigators as well as other ratepayers. IIPA has consistently urged IPCO to expand the existing Peak Rewards by broadening its eligibility criteria and increasing the compensation irrigators receive to more closely reflect the wholesale market cost of purchasing that power, two measures that should result in increased participation. The benefits of increased demand-side management include a reduction in the irrigator's contribution to coincident peak and their cost of service; lower, more stable rates for other customers; and, for the company, improved reliability and an opportunity to postpone building or buying more expensive new generation.

Expanding and appropriately funding these programs not only benefits individual irrigators, but reduces the irrigators' overall impact to Idaho Power Company's cost to serve irrigation load, increases reliability for all customer classes during peak seasons, and allows the company to reduce or postpone building expensive new generation or additional power purchases.

IIPA acknowledges that legislative, regulatory and environmental issues, including carbon sequestration and emissions standards, create uncertainty for the company and its ratepayers. These issues and their impact to the cost of providing energy will be resolved outside the company. They need to be addressed in order for utilities to move forward in implementing their IRPs and strategies to meet future growth, maintain reliability, and provide stable rates for consumers.

IIPA supports IPCO's proposal to reduce its reliance on regional market purchases. Not only are spot market purchases expensive, but the regional surplus energy supply is projected to decrease at least in the short-term and a significant portion of the existing surplus is owned by independent power producers, raising the question as to whether or not it will be available to regional utilities when needed and placing reliability at risk. Idaho and the region do not want to repeat the 2000-2001 Western Energy Crisis to the detriment of our economy.

IIPA appreciates the opportunity to submit these comments on behalf of the irrigation customer class.

Sincerely yours,

Lynn Tominaga

Lynn S. Tominaga
Executive Director

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2006 INTEGRATED RESOURCE PLAN (IRP)	)	CASE NO. IPC-E-06-24
	)	
	)	REPLY COMMENTS OF IDAHO POWER COMPANY

COMES NOW, Idaho Power Company ("Idaho Power" or "the Company"), by and through its attorneys of record, and in response to comments filed by the Commission Staff, Exergy, Industrial Customers of Idaho Power ("the ICIP"), NW Energy Coalition, Idaho Irrigation Pumpers Association and other interested parties, hereby submits the following reply comments.

1. ICIP Comments: The Nature of the IRP Process

Idaho Power's 2006 IRP is a comprehensive analysis of the Company's projected loads and resources available to meet those loads over the next 20 years. The integrated resource planning process is a continuous one, and a detailed plan is filed with the Company's regulators every two years for public review. The resulting document is the foundation for the Company's resource decisions.

Each filing requires considerable modeling and analysis using assumptions based on the best available information at a given point in time. To allow internal, stakeholder and regulatory review to occur, Idaho Power must lock down a number of the inputs to the IRP, such as the load forecast and the expected energy and capacity contributions available from existing and committed resources months before the plan is completed and filed. This must occur regardless of whether a specific project (1) has been selected in any pending Request for Proposal (RFP) process, (2) has received a Certificate of Public Convenience and Necessity, or (3) is completed and in-service, so that long-term resource planning can ultimately take place.

Although the ICIP implies in its Comments that Idaho Power does not revisit the ongoing prudency of its resource decisions as contracts are signed and regulatory approvals are received, that is simply not true. Idaho Power is mindful of industry, market and regulatory changes that affect its system and continues to evaluate the appropriateness of RFPs from the time they are released through construction. However, IRPs are designed to build upon previous plans so as to shape <u>future</u> resource decisions. Given current conditions, Idaho Power continues to believe that the Evander Andrews natural gas-fired combustion turbine facility was the appropriate choice for the peaking resource identified in the 2004 IRP.

2. ICIP Comments: Assumptions and Resources Not Included in the 2006 IRP

The Company understands the ICIP's desire to have the most current load forecast available at the time of filing used as the basis of Idaho Power's IRP. Because load forecasts form the foundation for resource modeling, Idaho Power made every attempt to use the most accurate load information available when it prepared the Sales and Load Forecast for the 2006 IRP. This forecast was completed on October 26, 2005. Short of scrapping months of modeling, analysis, and Integrated Resource Plan Advisory Council (IRPAC) feedback to incorporate the May 2006 Idaho Conservation Reserve Enhancement Program (CREP) assumptions, it was not possible to timely include any potential irrigation load reductions in the 2006 IRP filing. Furthermore, since CREP sign-up began on May 30, 2006 and runs until enrollment goals are met, or December 31, 2007, whichever comes first, the impacts of the CREP enrollment are more appropriately addressed in the 2008 IRP. Idaho Power has incorporated assumptions regarding CREP enrollment into its current load forecasts and those that will be used in the 2008 IRP process commencing in June 2007.

The ICIP also expressed concern that Idaho Power has not evaluated potential distributed generation opportunities for consideration in future resource decisions. In keeping with Commission Order No. 30201 issued December 15, 2006, Idaho Power is presently investigating the potential of using customers' emergency generator resources as a "virtual peaking plant". The Company has arranged for on-site demonstrations at other utilities that have developed such programs and will present a proposal to the Commission no later than June 1, 2007. The results of these findings will be used in Idaho Power's future resource decisions and will be incorporated into the 2008 IRP process that begins in June 2007.

3. ICIP and Exergy Comments: Transmission Upgrades

As part of the 2006 IRP process, Idaho Power undertook a comprehensive analysis of potential transmission upgrade projects that would benefit its system. Because the Company determined it would be most cost-effective to complete two

4. IPUC Staff Comments: Average Annual Gas Prices

Idaho Power appreciates Staff's recognition of the Company's efforts to improve its 2006 IRP by incorporating additional analyses and Commission recommendations. Idaho Power agrees with many of Staff's concerns and suggestions, and offers the following comments.

Staff expressed concern that Idaho Power's IRP appeared to utilize an annual average gas price even though the majority of its gas is purchased for the summer peaking months. In the 2006 IRP, future expected gas prices are presented on page 48 of Appendix D – Technical Appendix as annual averages for each of the years in the planning horizon. However, in the analysis of each portfolio, the Aurora model utilizes monthly average gas prices which have seasonalization factors applied. This is not apparent due to the manner in which the data is presented in the Technical Appendix.

5. IPUC Staff Comments: Irrigation Peak Rewards Program

Another issue Staff raised was how the Irrigation Peak Rewards program was factored into the 2006 IRP. In an Application filed one week before the 2006 IRP, Idaho Power requested the Commission approve modifications to the 2 year-old Irrigation Peak Rewards program to better manage load reduction targets and increase customer satisfaction. The Irrigation Peak Rewards program was a resource already included in the 2004 IRP for 30 MW, and the unmodified program is accounted for in the load/demand estimates/assumptions used in the 2006 IRP. Idaho Power does not expect the changes approved by the Idaho Commission on November 30, 2006 in Order No. 30194 to significantly change the estimated savings from this existing program. The changes are expected to increase savings in 2007, but only by about 3.9

transmission upgrades to the Pacific Northwest, Exergy and the ICIP incorrectly conclude that Idaho Power "exclusively focused" on the Pacific Northwest to the exclusion of expansion to the south and east. The 2006 IRP considered several transmission upgrades without a specific or dedicated generation resource at the end of a transmission line. These alternatives included upgrades to Montana, Wyoming, Nevada and the Pacific Northwest. Although the preferred portfolio included two transmission upgrades to the Pacific Northwest, that does not mean there are no other transmission upgrades in the preferred portfolio. In fact, the preferred portfolio includes significant transmission upgrades to the east to integrate the following resources: Wyoming Pulverized Coal (250 MW), Regional IGCC (250 MW assumed to be in Wyoming) and the INL Nuclear Power Purchase Agreement (250 MW), which is assumed to be served from the Next Generation Nuclear Plant anticipated to be built at INL. However, if these supply-side resources are not developed, then it is unlikely Idaho Power will proceed with the associated transmission upgrades.

The ICIP and Exergy comment that a number of generation resources might be developed in Wyoming and Montana in the future. While this may be true, Idaho Power does not intend to build transmission to the east without a corresponding plan to develop the associated supply-side resources, or evidence that surplus capacity exists and is available to meet the Company's resource needs. However, because the Pacific Northwest is a winter peaking region and Idaho Power's system is summer peaking, the Company believes transmission projects to the Pacific Northwest are prudent choices, and sufficient resources will be available to meet Idaho Power's needs.

MW per day. Depending on how the peak reduction is distributed and the time period used, the estimated program savings will still be very close to 30 MW.

CONCLUSION

Idaho Power views development of the IRP document as a valuable planning activity that positively shapes its long-term development of energy resources. The Company's integrated resource planning process will continue between filings of plan documents, as Idaho Power strives to improve the process and the associated analysis. The Company, as well as the next IRPAC, will consider and address many of the issues that Staff and others have identified in their comments in its 2008 IRP.

In light of the 2006 IRP filing and the written record in this docket, Idaho Power respectfully requests the Commission accept the filing of its 2006 IRP and find that it meets both the procedural and substantive requirements of Order No. 22299.

DATED this 9th day of February, 2007.

Lisa Nordstrom

LISA NORDSTROM
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 9th day of February, 2007, I served a true and correct copy of the above and foregoing REPLY COMMENTS OF IDAHO POWER COMPANY upon the following named parties by the method indicated below, and addressed to the following:

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Lisa Nordstrom

LISA NORDSTROM

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket LC 41 on the following named person(s) on the date indicated below by email at his or her last-known address(es) indicated below.

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DATED: February 16, 2007.

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Of Attorneys for Idaho Power Company