RICHARDSON & O'LEARY
ATTORNEYS AT LAW
Tel: 208-938-7900 Fax: 208-938-7904
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

RECEIVED
2011 MAR -4 PM 4:48
IDAHO PUBLIC
UTILITIES COMMISSION

March 4, 2011

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

RE: **IPC-E-10-27**

Dear Ms. Jewell:

We are enclosing for filing in the above-referenced docket an original and nine (10) copies, as well as an electronic copy on a disc, of the **INDUSTRIAL CUSTOMERS OF IDAHO POWER'S DIRECT TESTIMONY OF DR. DON READING**.

An additional copy is enclosed for you to stamp for our records.

Sincerely,

Gregory M. Adams
Richardson & O'Leary PLLC

encl.

Peter J. Richardson (ISB # 3195)
Gregory M. Adams (ISB # 7454)
Richardson & O'Leary, PLLC
515 N. 27th Street
P.O. Box 7218
Boise, Idaho 83702
Telephone: (208) 938-7901
Fax: (208) 938-7904
peter@richardsonandoleary.com
greg@richardsonandoleary.com

Attorneys for the Industrial Customers of Idaho Power

RECEIVED
2011 MAR -4 PM 4:48
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO

PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S REQUEST TO MODIFY RECOVERY OF INCENTIVES PAID TO SECURE DEMAND-SIDE RESOURCES	))))))	CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

DIRECT TESTIMONY OF DR. DON READING

March 4, 2011

Q. Would you please state your name, address, and occupation?

A. My name is Don Reading. I am a regulatory and utilities economist employed with Ben Johnson Associates, in Boise, Idaho. The Industrial Customers of Idaho Power (ICIP) have retained my consulting service for Idaho Power's request to modify recovery incentives paid to secure demand-side resources.

Q. Have you prepared an exhibit that describes your qualifications in regulatory and utility economics?

A. Yes. I am sponsoring Exhibit 201, which contains my curriculum vitae.

Q. Have other exhibits been prepared in support of this testimony?

A. Yes. I am also sponsoring Exhibits 202 through 210, which are documents produced by Idaho Power in discovery and in the integrated resource planning (IRP) process. I will explain the relevance of each in my testimony below.

Q. What is your purpose in this hearing?

A. My testimony will set forth the position of the ICIP with regard to the Company's application in this docket, and with regard to the settlement stipulation signed by the other parties to this docket. I will first provide by way of background an overview of the Company's Application and the settlement stipulation, and then I will provide the ICIP's position in opposition to the Application and the settlement stipulation.

BACKGROUND

1. The Company's Application

Q. Could you please describe the Company's request to modify recovery of incentives paid to secure demand side resources?

A. Idaho Power's Application, filed October 22, 2010, requests the Commission accept the Company's new demand-side resource business model.

The Company requests the Commission: (1) move the Company's three demand response program incentive payments into the Power Cost Adjustment (PCA) on a prospective basis beginning June 1, 2011; (2) establish a regulatory asset for its Custom Efficiency program incentive costs beginning January 1, 2011; and (3) change the carrying charge on the Energy Efficiency Rider (EE Rider) from the customer deposit rate (currently 1.00%) to the Company's authorized overall rate of return (currently 8.18%).

Q. Could you explain in more detail the request to recover demand response incentives through the PCA?

A. Idaho Power has three demand response programs: (1) the A/C Cool Credit Program, which is aimed at providing summer peak reduction by cycling participating residential customers' air-conditioning units, (2) the Agricultural Irrigation Peak Rewards Program, which switches off participating customers' irrigation pumps during times when the Company needs additional system peak resources, and (3) the FlexPeak Management Program, which is aimed at reducing commercial and industrial load during times of system peak.

The incentive payments for these three demand response programs are forecasted to be $14.96 million for the 2011/2012 PCA year, and $16.05 million for the 2012/2013 PCA year. I am sponsoring Exhibit 202, which is the Company's attachments to its Response to the ICIP's Production Request No. 28(d), and provides these estimates. The Irrigation Peak Rewards Program accounts for about three-quarters of the demand response program costs. It is important to note the Company is proposing to leave the program costs of these three demand response programs to be collected through the EE Rider, and shift the incentive payments to the PCA. The incentive payments are the majority of total program costs.

Q. How will the Company account for these demand response incentive payments in the future?

A. After this one year transfer of these demand response program expenses, the Company requests that it be allowed in future filings to place the normal or base level of expenses related to demand response incentives into base rates. Going forward, as part of the PCA case, the forecasted level of Idaho incentive payment expenses will be compared to the normal level included in base rates to determine the level of demand response cost recovery to be included in the PCA forecast. As proposed by the Company, any deviations between actual demand response incentive costs and forecasted costs will be included in the following year's PCA true-up.

Q. Could you please summarize Idaho Power's proposal to capitalize the Custom Efficiency Program?

A. The Company is proposing to capitalize direct incentive payments associated with the Custom Efficiency program to enable the Company to earn a return on a portion of its demand side resource activities. The Company proposes to start booking incentive payments to a regulatory asset account beginning January 1, 2011. The balance in the account would be included in the Company's revenue requirement at the time of a future rate case and would be amortized over four years with a carrying charge equal to the currently authorized rate of return.

Q. Could you please summarize Idaho Power's proposal to change the Energy Efficiency Rider Carrying Charge?

A. Idaho Power is currently authorized to collect funds for its demand side programs through the EE Rider, which is set at 4.75% of base rates. If the Company spends more money than it has collected through rates, it runs a negative balance in its EE Rider Account. Idaho

Power is allowed to charge the interest rate for customer deposits on the negative balance, which is currently a 1.00% interest charge.

Due to the large size of the negative balance of the EE Rider Account, Idaho Power proposes in this filing to increase the carrying charge from the a rate equal to the interest rate on customer deposits (1.00%) to the Commission's authorized rate of return, which is currently set at 8.18%. The Company states in its Application that changing the current carrying charge is particularly important should the Commission decide against part or all of its other proposals.

2. The Settlement Stipulation

Q. Did some of the parties enter into a settlement in this case?

A. Yes. Idaho Power, Commission Staff, Idaho Conservation League, Northwest Energy Coalition, Snake River Alliance, and the Community Action Partnership Association of Idaho entered into a settlement stipulation. The ICIP did not enter into the settlement stipulation.

Q. Could you explain the general terms of the settlement?

A. Under the proposed settlement, first, the settlement parties agreed to shift recovery for the incentive programs for the three demand response programs (A/C Cool Credits, Irrigation Load Control, and FlexPeak) from the EE Rider to the PCA. To keep customer classes revenue neutral until the next general rate case, the settlement calls for an interim per kilowatt-hour (kWh) tariff rate that recovers 100 % of DSM costs shifted to the PCA for each customer class in order to recover the same amount from each class as would have been recovered through a percentage charge against base rates. However, the settlement contains no agreement as to how demand response incentive amounts will be allocated to each customer class in an Idaho Power general rate case once the Company places the incentive costs in base rates.

Second, the settlement allows the Company to capitalize the incentive payments of the

Custom Efficiency program as a regulatory asset beginning January 1, 2011. The settlement allows the Company to implement a carrying charge equal to the current Commission authorized rate of return of 8.18 % until the Commission includes the regulatory asset in rates as part of the next general rate case. Once in rates, the asset would earn the current Commission approved authorized rate of return, and the settlement calls for the asset to be amortized over a seven-year period.

Third, the settling parties agreed that the EE Rider carrying charge will remain at the customer deposit rate (1.00%).

ICIP'S GENERAL POSITION

Q. Please summarize the ICIP's position in this case?

A. The ICIP is opposed to Idaho Power's Application and recommends the Commission reject the Company's proposal in total. The ICIP is opposed to the settlement because the ICIP does not believe the settlement goes far enough in addressing the ICIP's concerns with the Company's Application. The ICIP does not believe that a compelling case has been made to warrant implementing the proposed changes, which would have the same effect as increasing the EE Rider from 4.75% to 6.6%. Additionally, the ICIP is concerned with the dramatic policy shift to incentivize demand side activities implemented in the settlement, and is concerned about the precedent that would be set by the settlement without addressing all of the relevant issues.

Q. Does the Application or the settlement stipulation call for an increase in the EE Rider from the current 4.75%?

A. An underlying intent of Idaho Power's filing appears to be to find a method of increasing the EE Rider without asking for an increase in the percentage rate on the EE Rider.

The Company stated:

> The Rider percentage would have to increase from the current 4.75 percent to approximately 6.6 percent in January 2011 for the balance to be zero by the end of 2012. To take the Rider balance to zero in one year, by the end of 2011, the Rider percent would have to increase from the current 4.75 percent to approximately 7.5 percent.

Direct Testimony of Darlene Nemich, at p. 16.

The Company then goes on to indicate that the proposal in the Application would reduce the EE Rider negative balance to zero in two years. The requested modifications would hence result an effective increase in the EE Rider to 6.6%.

Q. Could you explain how the settlement results in an effective increase in the EE Rider?

A. The end effect of accepting the proposal to recover incentive payments for certain programs through other rate recovery mechanisms, without a corresponding decrease in the EE Rider percentage, is to effectively increase the amount charged to ratepayers while maintaining the appearance of keeping the EE Rider at its current 4.75%. The proposal simply masks increased conservation expenditures, and thereby would authorize substantial additional rate recovery for demand side programs from that currently authorized for Idaho Power.

Q. What is the justification for this increase in demand side expense recovery?

A. The justification appears to be that the Company has run up a substantial negative balance in its EE Rider account, and wants to recover those expenditures. The proposal in the Company's Application and the settlement stipulation would theoretically eliminate the current negative balance within two years.

Q. Do you believe that is an adequate reason to increase demand side expense recovery at this time?

A. No. There is no compiling reason the negative balance needs to be removed within a two-year period. The management and accounting of Idaho Power's conservation programs are under the Company's exclusive control the unauthorized accumulation of a large negative balance is no reason to allow the Company to move some of these conservation costs and receive a return on them. To allow the Company to simply increase its rate recovery whenever it spends more than it has been authorized to collect would give the Company no incentive to prudently manage its demand side programs.

Q. Do any other Idaho electric utilities recover an amount equivalent to 6.6% of base rates for their demand side programs?

A. No. Last year, Rocky Mountain Power asked the Commission to increase its customer efficiency services rate (Schedule No. 191) from 3.72% to 5.85%. The Commission allowed less than half the proposed increase and stated, in Order No. 32023, at page 5:

> The Commission finds it reasonable to authorize an increase in the Company's DSM Tariff rider from 3.72% to 4.72% for all customer classes (except special contracts) effective July 1, 2010. The unrecovered balance of the requested DSM expenses shall be booked to the DSM deferral account pending the Commission's examination of DSM issues in the rate case.

Less than year later, in the general rate case (PAC-E-10-07), the Commission effectively reduced Rocky Mountain Power's EE Rider to 3.4% of base rates by treating the program costs of the Irrigation Load Control Program as a system cost and by moving recovery of the program costs from the rider to base rates in Order No. 32196, at page 26. In other words, in the Rocky

Mountain Power case, the Commission moved the irrigation demand response program out of the EE Rider and into base rates, and issued a corresponding reduction in the EE Rider percentage.

I understand that, for Avista, the Commission has only authorized an EE Rider of 3.98% of base rates in Case No. AVU-E-09-06 through Avista's Schedule 91.

The Commission has thus shown a reluctance to increase the EE Rider for Idaho utilities above the 5% level. By accepting Idaho Power's proposal in this case it will maintain the appearance of putting a ceiling the EE Rider amount; however, ratepayers will be in reality be paying for conservation programs well above the current 4.75% level, and above any percentage previously authorized by the Commission.

Q. What is the history of Idaho Power's EE Rider?

A. Funding of Demand Side Management (DSM) programs with the Energy Efficiency Tariff Rider was initiated by Order No. 29026 and made effective on May 16, 2002. The Rider surcharge was initially set at 0.5% of each customer class's base revenues. The Commission authorized increases to 1.5% of base rates in May 2005, and to 2.5% of base rates in May 2008, in Order Nos. 29784 and 30560, respectively. In May 2009, the Commission approved a further increase in the EE Rider to 4.75% of base rates in Order No. 30814.

Q. What is the most recent Commission comment on the EE Rider level?

A. When the Company requested approval of a substantial increase in funding to the Northwest Energy Efficiency Alliance (NEEA) last year, in Order No. 31080 the Commission stated:

> The Commission has encouraged Idaho Power to increase its funding of DSM and energy efficiency programs in the past several years, and recently approved an increase in the Energy Efficiency Rider to 4.75% of sales revenues to support

those programs. The Rider funds are provided by customers and are not unlimited. The Commission expects Rider funds to be used judiciously to ensure customers receive tangible benefits from their payments to support energy efficiency programs. We recognize that some of NEEA's programs result in actual benefits to customers, especially over time, but that the actual benefit may be difficult to quantify in the short-term. Nonetheless, when Idaho Power in the future requests a Commission determination that its use of Rider funds was prudent, it must demonstrate a sufficient benefit to customers resulted from the Company's participation in NEEA. The Commission's approval of the Company's continued participation in NEEA, and the use of Rider funds to pay for that participation, is not a determination of prudency.

Q. How much money does Idaho Power collect through the EE Rider annually at the 4.75% level?

A. According to the Company's Response to Commission Staff's Production Request No. 3 in this case, the Company will collect $36,376,070 in 2011 and $37,103,591 in 2012 through the EE Rider. Unlike Table 2 in Exhibit No. 1 of Darlene Nemnich's testimony, these projections incorporate the load growth forecast contained in the Company's 2009 Integrated Resource Plan.

Q. How much would the Company collect from ratepayers under the proposal in this case?

A. The Company would not reduce the EE Rider percentage, and therefore it would still collect approximately $36 million through it in 2011. In addition, I am sponsoring Exhibit No. 203, which is the Company's Response to the ICIP's Production Request Nos. 15 and 22, wherein, the Company stated that the projected demand response expense that will be recovered through the PCA is $14.9 million in 2011. Thus, by the Company's figures, it would collect at least $50.9 million for demand side resources in 2011.

Q. Besides increasing recovery to over $50 million in 2011 and 2012, are there other ways for the Company address the problems it appears to have with running up a negative balance in EE Rider account?

A. I believe that the Company could scale back some of the programs that are not cost-effective and/or do not provide a direct benefit to Idaho customers. The easiest and best way to determine which programs are not cost-effective is to conduct third-party evaluations of the programs. In its Application in Case No. IPC-E-10-09, at paragraph 11(c), the Company stated that it only uses third-party evaluators when appropriate for the specific studies or evaluations. Some parties to that case, including the ICIP, suggested that Idaho Power should conduct more frequent third-party evaluations to better manage the demand side portfolio. In that case, in Order No. 32113, on page 9, the Commission stated, "Idaho Power should seek to employ independent evaluators for all of its DSM programs and take affirmative steps toward achieving measurable improvements in its documentation, verification and record-keeping processes for these programs." The ICIP agrees, and believes that doing so will help the Company identify unsuccessful programs and keep overall expenditures within a reasonable level, thereby reducing the negative balance in the EE Rider account.

Q. Are there any specific programs that you think the Commission should require the Company to scale back?

A. Yes. The ICIP has identified a few such programs in recent demand side resource dockets.

For example, the ICIP is concerned that the increased funding directed to NEEA does not provide a direct benefit to Idaho customers. Those funds are pooled outside of the state and the benefits to Idaho customers of many of the programs are difficult to identify. Idaho Power requested increased funding for its participation in NEEA last year in Case No. IPC-E-10-04. According to Staff's Comments in that case, on page 3, the Company's contribution to NEEA in 2009 was $1.9 million, but with the increased funding for the 2010-2014 time period, the Company's funding beginning in 2010 was to be $3.3 million per year. Although the Commission approved Idaho Power's continued participation in NEEA last year, Idaho Power's funding obligation includes an early termination clause in the event of Commission order disapproving of the continued, increased funding for NEEA. In light of the Commission's statements in the NEEA order quoted above and the impact on Idaho customers of the effective 6.6% EE Rider amount requested in this case, the Commission may want to reconsider whether continued increased funding of NEEA is warranted at this time.

Q. Are there any other examples of programs that may need to be scaled back, at least temporarily?

A. In the ICIP's Comments in Case No. IPC-E-10-09, the ICIP highlighted a few programs with cost-effectiveness problems. One program that appears to be achieving less than a cost-effective result is the A/C Cool Credits program. That is a peak reduction program on which ratepayers spent almost $3 million in 2008 and over $3.4 million in 2009. As explained in detail in those Comments, the Company has only calculated the cost-effectiveness of this program based on a 20-year model that uses financial and DSM alternative cost assumptions from the 2006 Integrated Resource Plan. Even when calculated over 20 years into the future, this program achieves only a total resource cost benefit (TRC) ratio of 1.09. The A/C Cool Credits program's initial expectations, set forth in Order No. 29702, at page 3, was for a positive benefit-cost ratio of 1.42 over a 30-year period. The program appears to be achieving far less peak reduction savings per dollar spent than the other demand response programs.

Its past performance has been less than stellar. I am sponsoring Exhibit No. 204, which contains the Company's attachment to its Response to the ICIP's Production Request No. 7(a). The table provided in Exhibit 204 demonstrates this program has achieved well below a 1.0 TRC value for each year for which the Company has actual figures, including TRC values of 0.09 in 2004, 0.24 in 2005, 0.34 in 2006, 0.33 in 2007, 0.56 in 2008, 0.73 in 2009. I am also sponsoring Exhibit No. 205, which is the Company's Response to the ICIP's Production Request No. 17, wherein it stated that the program is not now expected to achieve a cumulative TRC value of over 1.0 until 2017, or year 15 of the program. The Company indicates that the delay in achieving cost-effectiveness is attributable to a delay in obtaining the Company's targeted level of participants.

Additionally, a third-party evaluation of the program by Paragon Consulting identified a serious free rider problem. The report concluded that 52% of the participating customers were free riders. In other words, the program did not reduce peak whatsoever for over half of its participants. The Paragon report also concluded that the average demand reduction per curtailment in 2009 was well below the expected demand reduction found in other utility studies. The Company's 2009 DSM Report, at page 22, discussed plans to expand the program to reach 40,000 total participants, but perhaps the goal should be to reduce participation to include only those customers whose participation would reduce their peak energy use. Exhibit 205 shows the Company plans to spend approximately $2.5 million on the program in 2011, and $2 million annually in years afterwards. It appears that this program could achieve similar benefits to those it currently achieves with less expenditure.

This is just one of the Company's many programs, and perhaps more third-party evaluations would allow the Company to better identify how it could achieve more with the $36 million per year it is currently authorized to collect.

Q. Has the Commission approved all spending that resulted in the negative balance in the EE Rider Account as prudently spent?

A. It does not appear that the Commission has ever directly approved the prudency of the Company's expenditure on demand side programs in excess of the amount that it is authorized to recover through the EE Rider. In the most recent prudency case, Case No. IPC-E-10-09, regarding prudency of the Company's 2008-2009 EE Rider expenditures, Commission Staff noted, on page 4 of its Comments, that Idaho Power had accrued a negative balance of $3.94 million in 2008, and an additional $9.72 million in 2009. Those were amounts spent over and above the $50.7 million amount collected through the EE Rider in 2008 and 2009, and approved as prudently incurred expenditure by the Commission's Order No. 32113, at page 9. Thus, the Commission has not even approved the prudency of the amounts constituting the negative balance in the EE Rider account in 2008 and 2009. The ICIP submits that authorizing additional recovery mechanisms through the PCA or rate base to account for this over-spending, and to even incentivize the Company's demand side activities, may be putting the cart before the horse.

Q. What is the purpose of incentivizing an electric utility to pursue demand side resource programs?

A. In the direct testimony of John R. Gale, on page 7, filed in this docket he states, "I firmly believe that demand-side resources should be treated the same as supply-side resources, which is a recurring theme throughout my testimony." The theory is that the three demand response programs are analogous to variable energy resources accounted for through the PCA because they address peak, and that earning a return on the Custom Efficiency program is justified because the incentive payments for that program result in "utility plant-like" infrastructure investments at customers' facilities. The Company seems to assert that it is attempting to put demand side resources on "equal footing" with supply side resources to provide it with an incentive to more effectively run its programs, and apparently help it overcome its obvious disincentive to unsell electricity and avoid building future, costly plants which it can rate base at a substantial profit.

Q. Do you believe that this theory holds true?

A. No. The proposals advocated by the Company in this docket do not accomplish the goal of putting demand side resources on equal footing with supply side resources. In essence, the Company is saying the "business rationale" of making a profit by putting a demand side resource in rate base will put a demand side resource on "equal footing" with a rate-based plant because the Company is also allowed to make a profit on the demand side resource. As discussed later in these Comments, there are significant differences, such as the much shorter, four-year amortization period (or seven-year period in the stipulation) proposed for the Custom Efficiency regulatory asset, that treat supply-side and demand-side resources differently. Additionally, the Company's profit motives for the rate-based plant dwarf those of the rate-based demand side resource. In fact, even the Company stated, in its Response to the ICIP's Production Request No. 8, which I am sponsoring as Exhibit No. 206:

The Company does not believe that the requested relief would put demand-side resources on an equal footing with a supply-side resource; however, it does believe it would provide a similar business rationale for pursuing either demand-side resources or supply-side resources.

Creating a profit incentive for a demand-side resource does not put that demand side resource on equal footing with a rate-based supply side resource. The ICIP discussed this very well-established economic principle in its discussion of the Averich-Johnson effect in Comments in Case No. IPC-E-09-09, and I would refer the Commission to that discussion. In short, the Company has every incentive, and even a fiduciary obligation to its shareholders, to increase its profits, and the best way to do that is to build plants and put them in rate base. Effective demand side programs will prevent the need for new plants, and make it difficult to justify additional plants in the Company's public planning processes and proceedings before the Commission.

Q. Has the Company adequately incorporated demand side program achievements into its integrated resource planning processes?

A. The Company appears to use reduced projections for demand side program achievement in its IRP process when looking at the need for future plants. The benefit of the substantial amount of demand side resource expenditures should be avoided supply side costs that would otherwise be necessary for generation and transmission resources sufficient to meet larger load requirements by customers. Peak demand savings, in particular, should reduce the Company's need to build new peaking facilities such as gas-fired combustion generating plants and transmission lines. Thus, in theory, rates will be lower, and resources will be conserved, because the utility will not build and rate base new generating plant.

The Company uses its IRP to determine which cost effective resources it should acquire to meet load. However, the Company is placing limits on the level of demand side resources it plans to include in the 2011 IRP. In the Company's presentation, titled "Demand Side Management Demand Response," presented at the IRP Advisory Council Meeting on November 18, 2010, the Company used an "operational" limit for demand response programs of 330 MW for 2011, and only 351 MW through 2020. I am sponsoring Exhibit No. 207, which is slide 22 of this presentation. The projections in Exhibit 207 are at odds with the Company's Response to the ICIP's Production Request No. 22(c), in Exhibit 203 at page 5, in this case, wherein it justified the expenditure on its demand response programs – the incentive payments of which it proposes to collect through the PCA -- by stating it expects to achieve 376 MW of peak reduction with the three demand response programs in 2011. That is obviously higher than the 330 MW demand response operational limit currently being used in the IRP for 2011, and is even higher than the operational limit of 351 MW set for nine years from now in 2020. I would note also that the IRP document provides even lower demand response "targets" than the IRP operational limits.

Q. How do you reconcile that inconsistency?

A. I am sponsoring Exhibit 208, which is the Company's Response to the ICIP's Production Request No. 27. In that response, the Company attempted to reconcile the inconsistency between its lower projection for peak savings in the IRP process from the higher peak savings projection in this case where it states that it treats demand side resources the same as supply side resources. Idaho Power's response was:

> Case No. IPC-E-10-27 was filed on October 22, 2010, reflecting the demand response megawatt ("MW") reductions contained on the 2011 budgets prior to the completion of the demand response analysis for the 2011 Integrated Resource Plan. The MW reduction from demand response and the associated investments in

> this docket are forecasts. Ultimately, actual expenses will be included in determining the Power Cost Adjustment ("PCA") annually. In addition, the Company relies on the integrated resource planning process regarding load and peak growth projections.

Obviously, this response does not resolve the conflict. If demand side programs are to be truly put on "equal footing" with supply side resources, the projected benefits of the programs used to justify increased payment for the demand side programs through customer rates should be consistent with the projected demand reductions included in the IRP process from which the Company determines the need for supply side resources. That the Company is not currently using the same accounting of the benefits of these programs in the IRP process as it uses in this case serves to demonstrate that the Company is acting on its inherent incentive to build new plant rather than allow its demand response programs to reduce the need for new plant. It is difficult for a ratepayer group to overlook this discrepancy, and the Commission should be concerned.

SPECIFIC COMMENTS ON THE THREE PROPOSALS

1. Recovering Demand Response Incentives in the PCA

Q. Do you have any comments specific to the Company's request to recover demand response incentive payments through the PCA?

A. As proposed by Idaho Power, shifting the incentive payments for a one-year period for the three demand response programs from the EE Rider to the PCA will shift $1.6 million in program costs from some customer classes onto other customer classes. Schedules 9 and 19 along with special contract customers would pay an additional $1.6 million for the 2011/1012 PCA year while the other classes will pay less than if the program costs continued to be recovered through the EE Rider. The residential class alone would pay $1.45 million less.

Exhibit No. 202 provides the detailed calculations of this disproportionate effect.

The reason for this reallocation is that the EE Rider is calculated as a percentage of overall base rates (i.e. demand as well as energy charges), while the PCA is based on an all energy, or kilowatt-hour (kWh) basis. For high load factor customers whose energy use does not vary substantially from peak to non-peak times, allocation on an energy or kWh basis results in a disproportionate rate impact. These demand response programs are directed at reducing peak demand, and thus should be allocated on demand and not charged 100% to energy on a kWh basis.

In order to mitigate this shift among customer classes, the settlement stipulation addresses this in paragraph 6, by evening out the rate allocation impact in 2011 alone. If the Commission allows any demand response program incentive costs to be shifted to the PCA, the ICIP urges the Commission to institute this rate allocation mitigation called for in the stipulation.

Q. Does the rate case moratorium currently in effect touch on this issue of changing the allocation of cost recovery for demand side programs?

A. The terms of the stipulation in Case No. IPC-E-09-30 call for a moratorium on rate changes to take effect prior to January 1, 2012, with a few exceptions. The exceptions allow the Company to increase the EE Rider and to file its PCA, but they do not expressly provide that the Company may change the methodology by which the Company recovers costs through either mechanism. Altering the cost-allocation among customer classes for recovery of demand side expenditures, as proposed in the Company's Application, is different in kind from simply filing for an increase in recovery under the existing mechanisms. Thus, the Company's proposal does not appear to be allowed under the stipulation in Case No. IPC-E-09-30. That is another reason for the Commission to implement the mitigation of the cost-allocation if it allows demand response costs to be recovered through the PCA.

Q. Will there be any other impacts of the shift of recovery of these demand response costs to the PCA?

A. Yes. Following the 2011/2012 PCA year, the expected amount of the incentive payments for the three demand response programs will be included in the base rates, and only the difference in actual expenditures will be accounted for through the PCA. There has been no consensus as to how the Company will allocate these demand response incentive payments in the cost of service study in Idaho Power's next general rate case. The manner in which these incentive payments are treated in a cost of service study can have a significant rate impact on rates for a given class of customers. Before the ICIP could endorse this shift of costs, a determination on whether these costs would be assigned, for example, system-wide or assigned to the customer class receiving the incentives would need to answered. This question is a major policy question that the settlement stipulation expressly declines to address. The Commission should reject the stipulation for this failure alone. Without knowing the long-term effect on each customer class of the proposed shift to the PCA, the Commission cannot understand how this proposal will impact customers.

Q. How would the ICIP propose that the costs be allocated in a general rate case's cost of service study?

A. If accounted for through base rates, the ICIP would recommend the demand response costs should be allocated on a system-wide basis just as the Company accounts for other supply side resources. The ICIP's recommendation to treat these demand response resources as system-wide resources is consistent with the Commission's recent order in the Rocky Mountain Power general rate case allocating that utility's irrigation demand response program as a system-wide resource, in Order No. 32196, at p. 26. In addition, because these are programs aimed at reducing system demand, they should be considered demand-related in the cost of service study. To treat them any differently would not put them on "equal footing" with the Company's demand related supply side resources.

2. Capitalizing Custom Efficiency Incentive Payments

Q. Do you have any comments specific to the Company's proposal to capitalize the Custom Efficiency Incentive Payments?

A. Yes. The ICIP is very supportive of the Custom Efficiency program, and I would point out that it has been one of the most cost-effective programs in the Company's demand side resource portfolio. The ICIP would not necessarily be opposed to some forms of capitalizing the incentive payments associated with this program, but we cannot support the proposal in the Company's Application or the slightly modified proposal in the settlement stipulation.

In support of rate-basing the Custom Efficiency incentive payments, Mr. Gale in his direct testimony, on page 21, stated, "This action will keep the demand response assets on par with the supply-side assets and can adjust over time as the Commission sets the return to reflect changing circumstances." However, the Company's proposal and the slightly modified proposal in the settlement stipulation will not place this program on par with supply side assets.

Q. Could you explain why the proposed method of rate-basing the Custom Efficiency incentive payments will not place that program on par with supply side assets?

A. The vast majority of supply side resources have lives. Utilities' customers are, for example, paying the capital costs of a natural gas fired plant over its expected 35-year life. It is a basic tenet of ratemaking that the life of the rate-based asset should match the depreciation schedule or amortization period used to calculate rates.

However, the proposal to rate base the Custom Efficiency incentive payments intentionally accelerates the recovery of the capital costs of the equipment purchased. Many of the Custom Efficiency incentive payments go to physical equipment, electric motors for example, that have fairly long service lives. If the Company truly believes these demand side resources should be treated the same as supply side resources, then a four-year amortization period is far too short, and so too is the seven-year amortization period in the stipulation.

Q. Is there precedent supporting such a short amortization period?

A. I am only aware of one precedent, but it required a longer amortization period. Before the Company funded its demand side programs through the EE Rider, it was authorized to capitalize its expenditures on demand side resources. In Case No. IPC-E-97-12, the Company proposed a five-year amortization for its rate-based conservation expenditures, which was also supported by Staff. Other parties, including the ICIP, advocated for a recovery period of twenty-four years, to more closely match the actual life of the asset. The Commission authorized an amortization period of twelve years. In addition to reasoning that the expenditures were for items not owned by the Company, the Commission notably stated, on page 4, of Order No. 27660, "We also find significant the changes that are sweeping through the electric industry and the unpredictability that has resulted." At that time, the deregulation craze was sweeping through the electric industry, and the potential for stranded assets the utility would never recover through rates was a concern, thus providing additional justification for accelerating recovery of the demand side assets.

Regulatory stability and predictability are much more certain today in 1998. There is no reason, given today's regulatory certainty, that the amortization period should be any less than in 1998. Should the Commission approve moving Custom Efficiency payments into rate base, the ICIP recommends a twelve-year amortization period for capitalizing these incentive payments.

Q. Does accelerating the recovery of the asset have an impact on ratepayers?

A. Yes. Accelerating recovery results in higher rates in the near term. Thus, under the Company's proposal or the proposal in the settlement stipulation, the rate recovery for the incentive payments will require ratepayers to fully fund the program over the next few years rather than spreading them out over a longer period as would be true of a supply side resource.

Q. Do you have any other concerns with the Company's proposal to capitalize the Custom Efficiency program?

A. Yes. I have the same cost of service concerns with moving recovery of the Custom Efficiency incentive payments from the EE Rider into rate base that I mentioned above for the shift of the three demand response programs into base rates. I am sponsoring the Company's Response to the ICIP's Production Request No. 29 as Exhibit 209, in which the Company stated it has no plans for how the costs should be allocated in a cost of service study. Likewise, the settlement stipulation fails to address this issue. Leaving open the question of how these costs will be allocated in a general rate case is a failure to fully address the impact of the Company's proposal in this case. The method of allocating these costs could impact the Commission's determination of whether it makes sense to capitalize them at all. The ICIP urges the Commission to reject the proposal for its failure to address the whole issue.

3. The Request to Earn the Authorized Rate of Return on the EE Rider Account.

Q. Do you have any comments specific to the Company's request to earn its authorized rate of return on the negative balance in the EE Rider Account?

A. Yes. According to Exhibit No. 1 of Ms. Nemnich's direct testimony, the 2010 EE

Rider account balance is a negative $17 million. The Company forecasts it to be negative $22.3 million in 2011, and negative $29.7 million in 2012. The currently allowed return on that balance is the interest rate charged on customer deposits of 1.00 %. The Company is proposing to use its authorized rate of return of 8.18 %. I see no reason the carrying change should be changed from its current level of 1.00 %. The size of the balance should not be a surprise to Idaho Power and the Company allowed it to accrue with full knowledge of 1.00% carrying charge. The management and accounting of Idaho Power's conservation programs are under the Company's control. The accumulation of a large negative balance is no reason to now allow an eight-fold increase in the carrying charge. To allow the Company to earn a return on the negative balance, without restricting the Company to a maximum amount it may spend, would only incentivize it to overspend on programs regardless of their cost-effectiveness.

I therefore urge the Commission to reject the Company's request, and retain the current 1.00 % carrying charge for the EE Rider account, regardless of how it resolves the other issues.

CONCLUDING COMMENTS

Q. Do you have any concluding comments?

A. Regarding the cumulative impact of the Company's proposed modifications in this case, Mr. Gale stated, on page 24 of his direct testimony, "The positive results include the DSR business model would be fully implemented, DSR would be treated as a resource in the same manner as the supply-side resources, and there would be the potential to lower the Rider percentage in the future."

As shown above, the Company's proposal does not in reality put supply side and demand side resources on an "equal footing." The end result of the Company's Application is aimed at making a profit from demand side programs while giving customers the appearance of keeping the EE Rider percentage lower than the amount actually collected for these programs. I recommend the Commission should reject Idaho Power's Application in total, and, if not, the Company's requested alterations to the demand side recovery should be modified in the manner described in my testimony.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 4th day of March, 2011, I caused a true and correct copy of the foregoing **DIRECT TESTIMONY OF DR. DON READING ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER** to be served by the method indicated below, and addressed to the following:

Jean Jewell Idaho Public Utilities Commission 472 West Washington Street (83702) Post Office Box 83720 Boise, Idaho 83720-0074	( ) U.S. Mail, Postage Prepaid (x) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Lisa Nordstrom Donovan Walker Idaho Power Company PO Box 70 Boise, Idaho 83707	(x) U.S. Mail, Postage Prepaid ( ) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
John R. Gale Darlene Nemnich Idaho Power Company PO Box 70 Boise, ID 83707	(x) U.S. Mail, Postage Prepaid ( ) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Eric L Olsen Idaho Irrigation Pumpers Assoc. Inc Racine, Olsen, Nye, Budge & Bailey P.O. Box 1391 Pocatello, ID 83704	(x) U.S. Mail, Postage Prepaid ( ) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Nancy Hirsch NW Energy Coalition 811-1st Ave Ste 305 Seattle WA 98104	(x) U.S. Mail, Postage Prepaid ( ) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail

Benjamin J Otto
Idaho Conservation League
710 N 6th Street
Boise, ID 83702

(x) U.S. Mail, Postage Prepaid
( ) Hand Delivered
( ) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Ken Miller
Snake Rive Alliance
350 N 9th #B610
Boise, ID 83702

(x) U.S. Mail, Postage Prepaid
( ) Hand Delivered
( ) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Brad Purdy
Community Action Partnership Association
Of Idaho
2019 N. 17th Street
Boise, ID 83702

(x) U.S. Mail, Postage Prepaid
( ) Hand Delivered
( ) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Anthony Yankel
29814 Lake Rd
Bay Village, OH 44140

(x) U.S. Mail, Postage Prepaid
( ) Hand Delivered
( ) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Signed ______________________
Gregory M. Adams

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 201

Dr. Don Reading's Curriculum Vitae

Don C. Reading

Present position	Vice President and Consulting Economist
Education	B.S., Economics — Utah State University M.S., Economics — University of Oregon Ph.D., Economics — Utah State University
Honors and awards	Omicron Delta Epsilon, NSF Fellowship
Professional and business history	Ben Johnson Associates, Inc.: 1989 --- Vice President 1986 ---- Consulting Economist Idaho Public Utilities Commission: 1981-86 Economist/Director of Policy and Administration Teaching: 1980-81 Associate Professor, University of Hawaii-Hilo 1970-80 Associate and Assistant Professor, Idaho State University 1968-70 Assistant Professor, Middle Tennessee State University

Experience

Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 35 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, Texas, Utah, Wyoming, and Washington.

Dr. Reading has more than 30 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stock market levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import/export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates.

In the field of telecommunications, Dr. Reading has provided expert testimony on the issues of marginal cost, price elasticity, and measured service. Dr. Reading prepared a state-specific study of the price elasticity of demand for local telephone service in Idaho and recently conducted research for, and directed the preparation of, a report to the Idaho legislature regarding the status of telecommunications competition in that state.

Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power. Dr. Reading is currently a consultant to the Idaho Legislature's Committee on Electric Restructuring.

Since 1999 Dr. Reading has been affiliated with the Climate Impact Group (CIG) at the University of Washington. His work with the CIG has involved an analysis of the impact of Global Warming on the hydo facilities on the Snake River. It also includes an investigation into water markets in the Northwest and Florida. In addition he has analyzed the economics of snowmaking for ski area's impacted by Global Warming.

Among Dr. Reading's recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also performed analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin.

Dr. Reading has prepared econometric forecasts for the Southeast Idaho Council of Governments and the Revenue Projection Committee of the Idaho State Legislature. He has also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho

While at Idaho State University, Dr. Reading performed demographic studies using a cohort/survival model and several economic impact studies using input/output analysis. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination. He is currently a adjunct professor of economics at Boise State University (Idaho economic history, urban/regional economics and labor economic.)

Dr. Reading has recently completed a public interest water rights transfer case. He is currently a member of the Boise City Public Works Commission.

Publications

"Energizing Idaho", Idaho Issues Online, Boise State University, Fall 2006. www.boisestate.edu/history/issuesonline/fall2006_issues/index.html

The Economic Impact of the 2001 Salmon Season In Idaho, Idaho Fish and Wildlife Foundation, April 2003.

The Economic Impact of a Restored Salmon Fishery in Idaho, Idaho Fish and Wildlife Foundation, April, 1999.

The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1997.

"Cost Savings from Nuclear Resources Reform: An Econometric Model" (with E. Ray Canterbery and Ben Johnson) *Southern Economic Journal*, Spring 1996.

A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., November, 1988.

Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988.

"Post-PURPA Views," In Proceedings of the NARUC Biennial Regulatory Conference, 1983.

An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area (with R. Davies). Public Policy Research Center, Idaho State University, February 1980.

Phosphate and Southeast: A Socio Economic Analysis (with J. Eyre, et al). Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975.

Estimating General Fund Revenues of the State of Idaho (with S. Ghazanfar and D. Holley). Center for Business and Economic Research, Boise State University, June 1975.

"A Note on the Distribution of Federal Expenditures: An Interstate Comparison, 1933-1939 and 1961-1965." In *The American Economist*, Vol. XVIII, No. 2 (Fall 1974), pp. 125-128.

"New Deal Activity and the States, 1933-1939." In *Journal of Economic History*, Vol. XXXIII, December 1973, pp. 792-810.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 202

Attachment to Idaho Power's Response to ICIP Production Request

No. 28(d)

Idaho Power Company
Attachment to ICIP Data Request No. 28, Part (d)
Estimated Dollar Impact of DSR Incentive Collection through PCA
2011/2012 PCA Year

Line No		Rate Schedule No	Revenue-Based Allocation %* (Rider Approach)	Energy-Based Allocation %* (PCA Approach)	DSR Incentive Cost Allocation (Rider Approach)	DSR Incentive Cost Allocation (PCA Approach)	Estimated Dollar Impact
1	Residential Service	1	46.70%	37.03%	$6,988,275	$5,541,456	($1,446,819)
2	Master Metered Mobile Home Park	3	0.04%	0.04%	$6,503	$5,456	($1,047)
3	Residential Service Energy Watch	4	0.01%	0.01%	$1,124	$906	($218)
4	Residential Service Time-of-Day	5	0.01%	0.01%	$1,650	$1,332	($318)
5	Small General Service	7	1.95%	1.23%	$291,329	$184,167	($107,162)
6	Large General Service	9	23.37%	25.91%	$3,496,391	$3,877,522	$381,131
7	Dusk to Dawn Lighting	15	0.14%	0.05%	$20,896	$7,340	($13,557)
8	Large Power Service	19	10.14%	15.03%	$1,517,915	$2,249,577	$731,662
9	Agricultural Irrigation Service	24	12.42%	12.16%	$1,858,651	$1,818,963	($39,688)
10	Unmetered General Service	40	0.13%	0.12%	$20,167	$18,354	($1,813)
11	Street Lighting	41	0.34%	0.17%	$50,880	$25,528	($25,352)
12	Traffic Control Lighting	42	0.02%	0.03%	$3,400	$4,458	$1,059
13	Total Uniform Tariffs		95%	91.79%	$14,257,182	$13,735,059	($522,123)
15	Special Contracts:						
16	Micron	26	2.19%	3.80%	$327,911	$568,787	$240,876
17	J R Simplot	29	0.79%	1.39%	$118,078	$207,655	$89,577
18	DOE	30	1.01%	1.85%	$151,167	$276,477	$125,310
19	Hoku	32	0.73%	1.18%	$109,799	$176,158	$66,360
20	Total Special Contracts		5%	8.21%	$706,955	$1,229,078	$522,123
22	Total Idaho Jurisdiction		100%	100%	$14,964,137	$14,964,137	$0

* Allocation percentages calculated in the attachment to the Company's Response to Staff's Data Request No. 4.

Idaho Power Company
Attachment to ICIP Data Request No. 28, Part (d)
Estimated Dollar Impact of DSR Incentive Collection through PCA
2012/2013 PCA Year

Line No		Rate Schedule No	Revenue-Based Allocation %* (Rider Approach)	Energy-Based Allocation %* (PCA Approach)	DSR Incentive Cost Allocation (Rider Approach)	DSR Incentive Cost Allocation (PCA Approach)	Estimated Dollar Impact
1	Residential Service	1	46.70%	37.03%	$7,495,781	$5,943,891	($1,551,891)
2	Master Metered Mobile Home Park	3	0.04%	0.04%	$6,975	$5,852	($1,123)
3	Residential Service Energy Watch	4	0.01%	0.01%	$1,206	$972	($234)
4	Residential Service Time-of-Day	5	0.01%	0.01%	$1,770	$1,428	($341)
5	Small General Service	7	1.95%	1.23%	$312,486	$197,542	($114,944)
6	Large General Service	9	23.37%	25.91%	$3,750,308	$4,159,117	$408,809
7	Dusk to Dawn Lighting	15	0.14%	0.05%	$22,414	$7,873	($14,541)
8	Large Power Service	19	10.14%	15.03%	$1,628,150	$2,412,947	$784,797
9	Agricultural Irrigation Service	24	12.42%	12.16%	$1,993,631	$1,951,061	($42,570)
10	Unmetered General Service	40	0.13%	0.12%	$21,631	$19,687	($1,944)
11	Street Lighting	41	0.34%	0.17%	$54,575	$27,382	($27,193)
12	Traffic Control Lighting	42	0.02%	0.03%	$3,647	$4,782	$1,136
13	Total Uniform Tariffs		95%	91.79%	$15,292,574	$14,732,534	($560,040)
15	Special Contracts:						
16	Micron	26	2.19%	3.80%	$351,725	$610,094	$258,369
17	J R Simplot	29	0.79%	1.39%	$126,653	$222,736	$96,082
18	DOE	30	1.01%	1.85%	$162,145	$296,555	$134,410
19	Hoku	32	0.73%	1.18%	$117,773	$188,951	$71,179
20	Total Special Contracts		5%	8.21%	$758,296	$1,318,336	$560,040
22	Total Idaho Jurisdiction		100%	100%	$16,050,870	$16,050,870	$0

* Allocation percentages calculated in the attachment to the Company's Response to Staff's Data Request No. 4.

Idaho Power Company
Attachment to ICIP Data Request No. 28, Part (d)
Increase of Energy Efficiency Rider to 6.65%
Estimated Dollar Impact

Line No		Rate Schedule No	Test Year Base Revenue*	Rider Revenues at 4.75%	Rider Revenues at 6.65%	Estimated Dollar Impact
1	Residential Service	1	$374,473,751	$17,787,503	$24,902,504	$7,115,001
2	Master Metered Mobile Home Park	3	$348,454	$16,552	$23,172	$6,621
3	Residential Service Energy Watch	4	$60,254	$2,862	$4,007	$1,145
4	Residential Service Time-of-Day	5	$88,403	$4,199	$5,879	$1,680
5	Small General Service	7	$15,611,161	$741,530	$1,038,142	$296,612
6	Large General Service	9	$187,357,640	$8,899,488	$12,459,283	$3,559,795
7	Dusk to Dawn Lighting	15	$1,119,748	$53,188	$74,463	$21,275
8	Large Power Service	19	$81,339,021	$3,863,603	$5,409,045	$1,545,441
9	Agricultural Irrigation Service	24	$99,597,679	$4,730,890	$6,623,246	$1,892,356
10	Unmetered General Service	40	$1,080,650	$51,331	$71,863	$20,532
11	Street Lighting	41	$2,726,473	$129,507	$181,310	$51,803
12	Traffic Control Lighting	42	$182,173	$8,653	$12,115	$3,461
13	Total Uniform Tariffs		$763,985,407	$36,289,307	$50,805,030	$14,515,723
15	Special Contracts:					
16	Micron	26	$17,571,441	$834,643	$1,168,501	$333,857
17	J R Simplot	29	$6,327,341	$300,549	$420,768	$120,219
18	DOE	30	$8,100,440	$384,771	$538,679	$153,908
19	Hoku	32	$5,883,679	$279,475	$391,265	$111,790
20	Total Special Contracts		$37,882,901	$1,799,438	$2,519,213	$719,775
22	Total Idaho Jurisdiction		$801,868,308	$38,088,745	$53,324,242	$15,235,498

*Test year base revenues reflect the June 1, 2010 through May 31, 2011 test year as provided in compliance filings made June 1, 2010, with the Idaho Public Utilities Commission pursuant to Order Nos. 31091, 31093, and 31097.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 203

Idaho Power's Response to ICIP Production Request Nos. 15 and 22

REQUEST NO. 15: Reference Direct Testimony of Darlene Nemnich, p. 8, lines 13-15.

(a) If the Company will pay for the estimated $13.7 million in DSR program costs from PCA rates in 2011, will the Company file to reduce the EE rider recovery by that amount?

(b) If the answer to (a) is "no," please explain how the request to recover the $13.7 million in DSR program expenses through the PCA is not analogous to an increase in the EE rider by $13.7 million in 2011.

(c) Please provide the following estimates for this projected $13.7 million expenditure:

	A/C Cool Credits	Flex Peak	Irrigation Peak Rewards
estimated expenditure ($)			
peak reduction estimate (MW)			
expenditure/ peak reduction ($/MW)			

RESPONSE TO REQUEST NO. 15:

(a) Given the Company's current projections used in this filing and assuming the Commission adopts Idaho Power's proposals while keeping the Rider funding level at 4.75 percent, the Rider balance is expected to approach zero sometime in the middle of the year 2012. The Rider is a balancing account and ideally would remain close to zero. The Company will monitor the adequacy of the Rider funds on a periodic basis and if an adjustment to the funding level needs to be made, the Company will file an appropriate request with the Commission.

(b) It is analogous.

(c)

	A/C Cool Credit	FlexPeak	Irrigation Peak Rewards
estimated expenditure ($)	$798,000	$1,210,801*	$11,744,534
peak reduction estimate (MW)	48	43	285
expenditure/ peak reduction ($/MW)	$16,625	$28,158*	$41,209

On the "estimated expenditure ($)" row (row one) above, Idaho Power has provided the information requested. However, in preparing this Response, the Company identified an underestimation (*) of the Flex Peak 2011 estimated expenditures. A more accurate estimate for 2011 is $2,421,603, resulting in a $/MW of $56,316. This results in a total estimated incentive value of $14,964,137 instead of $13,753,335 as referenced in the Application and testimony.

The dollars per megawatt ("MW") calculated in row three of the table above is only a portion of the dollars per MW needed to offer a demand response program. Excluded from the A/C Cool Credit and Irrigation Peak Rewards programs are Idaho Power labor, third-party contract expenses, and material (equipment) purchases. Excluded from the FlexPeak expenses are Idaho Power's labor and overheads. The expenses for Idaho Power-managed demand response programs are front loaded as they are for supply-side resources. However, with a performance contract, the expenses are flat or linear based on the amount of demand reduction.

The response to this Request was prepared by Pete Pengilly, Customer Research and Analysis Leader, Idaho Power Company, in consultation with Lisa D. Nordstrom, Lead Counsel, Idaho Power Company.

DATED at Boise, Idaho, this 14th day of December 2010.

Lisa D. Nordstrom

LISA D. NORDSTROM
Attorney for Idaho Power Company

REQUEST NO. 22: Reference Idaho Power's Response to ICIP Request No. 15(c).

(a) Does Idaho Power admit that the identified error means that its filing actually requests recovery the $14.9 million (not $13.7 million) in DSR program expenses through the PCA?

(b) Does Idaho Power admit that this is analogous to an increase in the EE rider by $14.9 million in 2011?

(c) Please provide the $/MW figures including all "dollars per MW need to offer the demand response program" for each of the three programs.

(d) If the data requested in (c) is unavailable, please explain why, and please explain how Idaho Power can accurately test cost-effectiveness of the programs without cost data that incorporates all dollars needed to offer the programs.

(e) Does Idaho Power expect that the increased funding of the Flex peak program of $2,421,603 will result in a greater MW reduction than provided in the response? If so, please provide an updated $/MW figure. Please explain how the MW reduction is derived, and provide supporting work papers or documents.

(f) Please explain how the MW reduction was derived for the A/C Cool Credits and the Irrigation Peak Rewards programs, and provide supporting work papers or documents.

RESPONSE TO REQUEST NO. 22:

(a) As a point of clarification, the Company is not asking for the recovery of any expenses in this filing. Idaho Power is proposing a new method of recovering demand response expenses. The 2011 forecast expenses of $14.9 million for demand

Exhibit No. 203
IPC-E-10-27
Reading, ICIP
Page 4

response are used for demonstrative purposes. This level of cost recovery for demand response is currently budgeted to the Idaho Rider.

(b) The difference between what the Company is proposing and increasing the Rider by $14.9 million in 2011 is primarily a matter of the method and timing of cost recovery for demand response program incentives. If the Company's proposal is approved, the 2011 forecast demand response incentives would be recovered from June of 2011 through May 2012. In the 2011-12 PCA year, the forecast amount would be trued-up with the actual expenses and any over (under) recovery would reduce (or increase) rates beginning June 2012. Under the current cost recovery method, the Idaho Rider's negative balance would increase with actual demand response program incentives as they are incurred in 2011. Recovery of the Rider deficit would continue beyond 2011.

(c) The expenses and megawatt ("MW") reduction in the table below are forecast for 2011.

	A/C Cool Credit	Flex Peak	Irrigation Peak Rewards
Total Estimated Expenditures ($) 2011	$1,825,640	$2,494,231	$13,596,767
Estimate Peak Reduction (MW) 2011	48	43	285
Total Expenditure/Peak Reduction ($/MW)	$38,034	$58,005	$47,708

(d) Data for Request No. 22(c) was provided above.

(e) No. As stated in the Company's Response to ICIP's Production Request No. 15(c), "However, in preparing this Response, the Company identified an underestimation (*) of the Flex Peak 2011 estimated expenditures. A more accurate estimate for 2011 is $2,421,603, resulting in a $/MW of $56,316." Note, there was no change in funding level of the Flex Peak program, the Company identified an under estimation only.

As stated in the Application for IPC-E-09-02, "Idaho Power and EnerNOC have agreed upon targets for each year; 2009 through 2013. The targets for demand reduction for these years are 2 MW, 30 MW, 40 MW, 50 MW, and 50 MW, respectively." The MW reduction in the table above aligns with this filing and the agreement between Idaho Power and EnerNOC.

The MW reduction for FlexPeak Management is derived from interval meter data at the participant's site. Please see *FlexPeak Management Demand Response Program Report*, pages 6 through 8, filed with the Commission on February 26, 2010, and included in the *Demand-Side Management 2009 Annual Report, Supplement 2: Evaluation*. For your convenience, a copy of the report is attached. In addition, an electronic copy is also available at:

http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE0902/company/20100301FLEXPEAK%20PROGRAM%20REPORT.PDF.

(f) For an explanation of how the load reduction for the A/C Cool Credit program is estimated, please see the Company's Response to ICIP's Production Request No. 7(c). In addition, attached is a copy of an April 9, 2007, analysis entitled *Load Reduction Analysis of the 2006 Air Conditioning Cool Credit Program.*

For an explanation of how the load reduction for the Irrigation Peak Rewards program is estimated, please see pages 10 through 19 of the attached *Irrigation Peak Rewards Program Report,* filed with the IPUC on December 1, 2009. An electronic copy is also available on Idaho Power's website at:

http://www.idahopower.com/pdfs/EnergyEfficiency/Reports/2009IrrigationPeakRewards.pdf.

The response to this Request was prepared by Pete Pengilly, Customer Research & Analysis Leader, Idaho Power Company, in consultation with Lisa D. Nordstrom, Lead Counsel, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 204

Attachment to Idaho Power's Response to ICIP Production Request

No. 7(a)

Case No. IPC-E-10-27
First Production Request ICIP
Response to No. 7 a
12/14/2010

IDAHO POWER.
An IDACORP Company

AC Cool Credit

Cost-Effectiveness Model
Updated: 3/15/2010

Cost-Effectiveness Assumptions		
Full Annual Participation (AC units)		40,000
Life (years)		20
Number of events (per season)		15
Load Reduction (kW per AC unit)		1.12
Avoided energy during SONP (kWh/Participant		0.9
Shifted energy to SMP (kWh/Participant) - snapback energy		0.5
SONP Line Loss		13.0%
SMP Line Loss		10.9%
Discount Rate		6.98%

Cost-Effectiveness Results		
Total Cost (20 Year NPV)	$	31,578,689
Total Benefit (20 Year NPV)	$	34,474,357
Total Resource Cost Ratio (20 Year)		1.09
Levelized Cost (20 Year, $/kW/Year)	$	58.57

Exhibit No. 204
IPC-E-10-27
Reading, ICIP
Page 1

IDAHO POWER.
An IDACORP Company

1	2003	-	$	[illegible]	$	-	$	-	$	275,644	[illegible]
2	2004	452	$	26,749	$	314	$	27,063	$	287,253	0.09
3	2005	3,051	$	180,558	$	1,819	$	182,377	$	734,062	0.24
4	2006	6,328	$	410,814	$	4,398	$	415,212	$	1,235,476	0.34
5	2007	12,204	$	792,284	$	11,946	$	804,230	$	2,426,153	0.33
6	2008	25,538	$	1,657,927	$	16,327	$	1,674,254	$	2,969,877	0.56
7	2009	38,463	$	2,497,008	$	24,071	$	2,521,079	$	3,451,988	0.73
8	2010	50,624	$	3,189,312	$	22,318	$	3,211,630	$	2,580,734	1.24
9	2011	50,624	$	3,189,312	$	25,951	$	3,215,263	$	2,500,000	1.29
10	2012	50,624	$	3,189,312	$	32,199	$	3,221,511	$	1,905,500	1.69
11	2013	50,624	$	3,189,312	$	34,613	$	3,223,925	$	1,962,665	1.64
12	2014	50,624	$	3,189,312	$	35,350	$	3,224,662	$	2,021,545	1.60
13	2015	50,624	$	3,189,312	$	35,258	$	3,224,570	$	2,082,191	1.55
14	2016	50,624	$	3,189,312	$	34,999	$	3,224,311	$	2,144,657	1.50
15	2017	50,624	$	3,189,312	$	36,380	$	3,225,692	$	2,208,997	1.46
16	2018	50,624	$	3,189,312	$	37,428	$	3,226,740	$	2,275,267	1.42
17	2019	50,624	$	3,189,312	$	38,109	$	3,227,421	$	2,343,525	1.38
18	2020	50,624	$	3,189,312	$	39,992	$	3,229,304	$	2,413,830	1.34
19	2021	50,624	$	3,189,312	$	41,183	$	3,230,495	$	2,486,245	1.30
20	2022	50,624	$	3,189,312	$	41,315	$	3,230,627	$	2,560,833	1.26
[illegible]											

Levelized Cost $ 58.57

1	2010	50,624	3,189,312	$	22,318	$	3,211,630	$	2,580,734	1.24
2	2011	50,624	3,189,312	$	25,951	$	3,215,263	$	2,500,000	1.29
3	2012	50,624	3,189,312	$	32,199	$	3,221,511	$	1,905,500	1.69
4	2013	50,624	3,189,312	$	34,613	$	3,223,925	$	1,962,665	1.64
5	2014	50,624	3,189,312	$	35,350	$	3,224,662	$	2,021,545	1.60
6	2015	50,624	3,189,312	$	35,258	$	3,224,570	$	2,082,191	1.55
7	2016	50,624	3,189,312	$	34,999	$	3,224,311	$	2,144,657	1.50
8	2017	50,624	3,189,312	$	36,380	$	3,225,692	$	2,208,997	1.46
9	2018	50,624	3,189,312	$	37,428	$	3,226,740	$	2,275,267	1.42
10	2019	50,624	3,189,312	$	38,109	$	3,227,421	$	2,343,525	1.38
11	2020	50,624	3,189,312	$	39,992	$	3,229,304	$	2,413,830	1.34
12	2021	50,624	3,189,312	$	41,183	$	3,230,495	$	2,486,245	1.30
13	2022	50,624	3,189,312	$	41,315	$	3,230,627	$	2,560,833	1.26
14	2023	50,624	3,189,312	$	43,776	$	3,233,088	$	2,637,658	1.23
15	2024	50,624	3,189,312	$	45,055	$	3,234,367	$	2,716,787	1.19
16	2025	50,624	3,189,312	$	45,672	$	3,234,984	$	2,798,291	1.16
17	2026	50,624	3,189,312	$	46,360	$	3,235,672	$	2,882,240	1.12
18	2027	50,624	3,189,312	$	47,154	$	3,236,466	$	2,968,707	1.09
19	2028	50,624	3,189,312	$	47,048	$	3,236,360	$	3,057,768	1.06
20	2029	50,624	3,189,312	$	46,910	$	3,236,222	$	3,149,501	1.03
[illegible]										

Levelized Cost $ 47.08

Exhibit No. 204
IPC-E-10-27
Reading, ICIP
Page 2

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 205

Idaho Power's Response to ICIP Production Request No. 17

<u>REQUEST NO. 17</u>: Reference Idaho Power's Response to ICIP Request No. 7(a) and the attachment thereto.

(a) Why does the Company evaluate the cost-effectiveness of the A/C Cool Credits program based on projected data for the 20-year life cycle of the program when it possesses actual data from which it has provided cost-effectiveness of the program for the years 2008 and 2009, and will soon have similar data for 2010?

(b) Based on the table provided, the program has achieved well below a 1.0 TRC value for each year for which the Company has actual figures, including TRC values of 0.09 in 2004, 0.24 in 2005, 0.34 in 2006, 0.33 in 2007, 0.56 in 2008, 0.73 in 2009, but the Company projects it will achieve 1.0 TRC value in future years. Based on the Company's projection, in what year will the program's cumulative TRC be 1.0? Please explain why this program should not need to prove cost-effective sooner or be discontinued.

(c) Please provide the updated calculation for 2010 once the books have been closed and financial records reported.

(d) Please reconcile the statement in the response that "expenses for Idaho Power demand response programs are front loaded," with the data in the chart provided in response to ICIP Request No. 6, which shows the cost for this program have escalated each year since 2008.

(e) Does Idaho Power posses data demonstrating that the A/C Cool credits program costs are front loaded? If so, please provide such data and explain. If not, please explain the basis to use a 20-year levelized cost benefit analysis.

Exhibit No. 205
IPC-E-10-27
Reading, ICIP
Page 1

(f) What is the amortization period for the A/C Cool Credits program? Given the cost-effectiveness of the A/C Cool Credit program is determined based on the 20-year life of the program, please explain why a 20-year amortization period would not be appropriate.

RESPONSE TO REQUEST NO. 17:

(a) As stated in the Company's Response to ICIP's Production Request No. 7:

> As stated in the Company's Application, it is the Company's goal to keep the treatment of demand-side resource assets on par with supply-side assets. The levelized cost of a supply-side resource is viewed based on a life-cycle analysis, as is the A/C Cool Credit program.

As stated in *Demand Response 2009 Annual Report, Supplement 1: Cost-Effectiveness*, page 2:

> To be consistent with the IRP, and since demand response programs are inherently different from energy efficiency programs, the B/C ratios for A/C Cool Credit and Irrigation Peak Rewards are calculated over a 20-year program life . . . .

(b) Please see the Company's Response to ICIP's Production Request No. 7. Based on the table provided, the net present value ("NPV") of benefits exceeds the NPV of costs by 2017, or year 15 of the program.

As stated in the Commission's Order No. 29702 approving the A/C Cool Credit Program:

> The Company anticipates that there will be 40,000 participants in the AC Program within five years . . . . The higher initial costs are attributable to the Company's purchase and installation of the direct load control devices.

As stated in the Company's Response to ICIP's Production Request No. 7(d), the Company anticipates achieving its goal for 40,000 participants in 2011.

Order No. 29702 further states:

> . . . Staff opined that this demand-side program offers a better alternative of shaping or reducing customer load than purchasing a supply-side generation resource.

As stated in the Company's Response to ICIP's Production Request No. 7:

> As stated in the Company's Application, it is the Company's goal to keep the treatment of demand-side resource assets on par with supply-side assets. The levelized cost of a supply-side resource is viewed based on a life-cycle analysis, as is the A/C Cool Credit program.

As stated in *Demand Response 2009 Annual Report, Supplement 1: Cost-Effectiveness*, page 2:

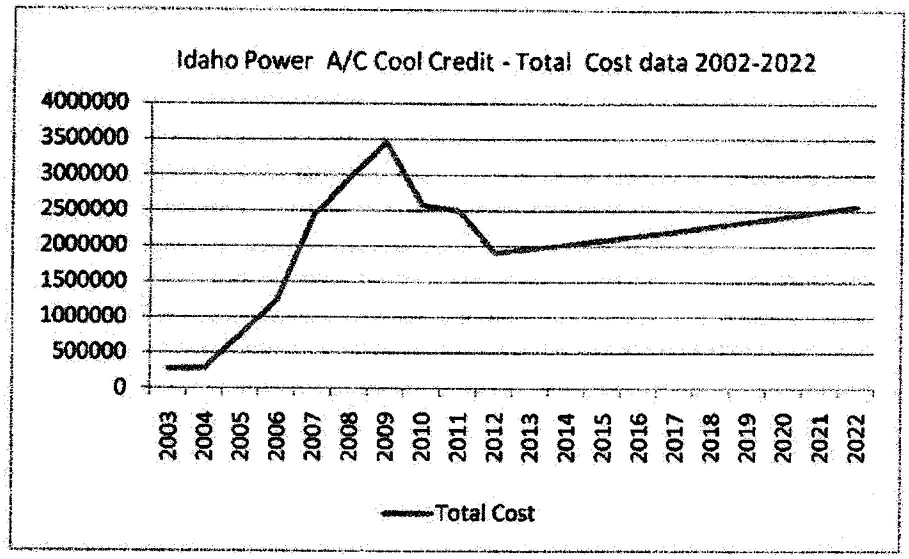
> To be consistent with the IRP, and since demand response programs are inherently different from energy efficiency programs, the B/C ratios for A/C Cool Credit and Irrigation Peak Rewards are calculated over a 20-year program life . . . .

It seems clear that the Company, Commission Staff, and the Commission's expectations are that the A/C Cool Credit program would not be cost-effective on an annual basis because of the initial costs to start this program. The expectations are that this program will be cost-effective on a life-cycle basis, as is a supply-side resource.

The development of a demand response program is similar to the building of a supply-side resource. Once the A/C Cool Credit program is fully developed (or close to having 40,000 participants), it will be cost-effective. This is very similar to a supply-side resource, by the fact that a supply-side resource is not cost-effective until it is built and running. The benefit of a demand response program is that it can be utilized as a resource while it is being "built."

(c) Results of all 2010 demand-side management ("DSM") activities, energy savings, demand savings, and investments will be reported following the closing of the 2010 books and public disclosure thereof. Results of the DSM activities will not be finalized until the *Demand-Side Management 2010 Annual Report* is filed with the Commission on March 15, 2011.

(d) Please see the graph below of the utility cost data provided in the Company's Response to ICIP's Production Request No. 6.



The above chart demonstrates that the A/C Cool Credit program costs increase in the earlier years. The data provided in the Company's Response to ICIP's Production Request No. 6 shows an increase in expenses for the first seven years of the program, a projected decrease in years eight through ten, and beyond year ten, the expenses are escalated at three percent through year twenty.

(e) See the Company's Response to ICIP's Production Request No. 17(d).

(f) As stated in Ms. Nemnich's testimony, the Company currently includes and recovers all costs for the A/C Cool Credit program through the Rider. More specifically, these costs include the variable incentive payments of which the Company is proposing to recover through the PCA.

The Company expenses A/C Cool Credit incentive payments through the Rider account in the period in which the payments are made, similar to the treatment of fuel expenses for a supply-side resource. The Company then matches the revenues received with those expenses. Technically, the current year incentive payment expenses are not considered an amortization expense and the payments do not represent the systematic expensing of a long-lived asset. In addition, the existing treatment of matching revenues with expenses within the Rider complies with General Accepted Accounting Principles.

Finally, the benefits derived from A/C Cool Credit incentive payments occur during the same period in which the payments are made. Therefore, a long-lived asset with a 20-year amortization period would not be appropriate

Including A/C Cool Credit incentive payments in the Power Cost Adjustment ("PCA") will afford comparable recovery and timing as in the Rider balancing account.

The response to this Request was prepared by Pete Pengilly, Customer Research & Analysis Leader, Idaho Power Company, in consultation with Lisa D. Nordstrom, Lead Counsel, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 206

Idaho Power's Response to ICIP Production Request No. 8

<u>REQUEST NO. 8</u>: Reference Application at ¶ 4. Does Idaho Power believe that the requested relief will place DSR on a "equal footing" with supply side resources? Please explain how Idaho Power's profit incentive associated with building a new gas peaking plant compares to Idaho Power's profit incentive associated with its DSR programs as they would exist with the requested relief in this case. Please provide supporting evidence or calculations.

<u>RESPONSE TO REQUEST NO. 8</u>: The Company does not believe that the requested relief would put demand-side resources on an equal footing with a supply-side resource; however, it does believe it would provide a similar business rationale for pursuing either demand-side resources or supply-side resources.

Creating a profit incentive for a demand-side resource is comparable to what is allowed for supply-side resources.

The response to this Request was prepared by Ric Gale, Senior Vice President of Corporate Responsibility, Idaho Power Company, in consultation with Lisa D. Nordstrom, Lead Counsel, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 207

Idaho Power's November 18, 2010 IRP Advisory Council

Presentation, Slide 22

Exhibit No. 207
IPC-E-10-27
Reading, ICIP
Page 1

IDAHO POWER
An IDACORP Company

Analysis Results

Year	Peak Load	60th Hour Peak Load	Energy Efficiency	Existing and Committed Supply-Side Resources	L&R Balance Deficit Position w/o DR Programs	Achievable DR with 60 Hour Programs	Demand Response Target	Operational Target
2011	3,515	3,209	17	3,120	378	306	306	330
2012	3,430	3,227	34	3,241	155	203	155	310
2013	3,684	3,326	50	3,390	244	358	244	315
2014	3,770	3,422	65	3,386	319	348	319	315
2015	3,854	3,532	79	3,382	393	322	322	321
2016	3,925	3,566	93	3,379	453	359	359	351
2017	3,991	3,588	108	3,374	509	403	403	351
2018	4,056	3,650	122	3,368	566	406	406	351
2019	4,123	3,711	136	3,363	624	412	412	351
2020	4,190	3,827	150	3,358	682	363	363	351

Minimum

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 208

Idaho Power's Response to ICIP Production Request No. 27

REQUEST NO. 27: Reference the Company's Response to ICIP's Request Nos. 15 and 22 (stating the estimated 2011 Peak for the 3 Demand Response programs (A/C Cool Credit, Flex Peak, Irrigation Peak Rewards) is 376 MW (285+43+48=376)); and Power Point Presentation titled: "Demand Side Management Demand Response," presented at the IRPAC Meeting November 18, 2010, available as slide 22 at: http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2011/20101118IRPACMeetingPresenationSlides_Web.pdf (discussing an "operational" limit through 2020 of 351 MW (330 MW for 2011) for the Company's Demand Response programs.

Please explain why the 376 MW for 2011 provided in this case exceeds the estimated operational limit provided in the IRPAC meeting. Will the Company rely upon the projections in this docket in future analysis regarding load and peak growth projections used in its IRP process?

RESPONSE TO REQUEST NO. 27: Case No. IPC-E-10-27 was filed on October 22, 2010, reflecting the demand response megawatt ("MW") reductions contained on the 2011 budgets prior to the completion of the demand response analysis for the 2011 Integrated Resource Plan.

The MW reduction from demand response and the associated investments in this docket are forecasts. Ultimately, actual expenses will be included in determining the Power Cost Adjustment ("PCA") annually. In addition, the Company relies on the integrated resource planning process regarding load and peak growth projections.

The response to this Request was prepared by M. Mark Stokes, Manager, Power Supply Planning, and Pete Pengilly, Customer Research & Analysis Leader, Idaho Power Company, in consultation with Lisa D. Nordstrom, Lead Counsel, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

INDUSTRIAL CUSTOMERS OF IDAHO POWER

READING, DI

TESTIMONY

EXHIBIT NO. 209

Idaho Power's Response to ICIP Production Request No. 29

<u>REQUEST NO. 29</u>: Reference Direct Testimony of Darlene Nemnich, pages 8 and 9 (stating the Company proposes to collect DSR incentive payments through the PCA). How does the Company propose to include the DSR incentive payments in its cost-of-service study in a rate case? Would these DSR incentive costs be directly assigned to the customer class that received the incentive payments or assigned as a system resource? Would they be considered energy related or demand related? Please explain, and estimate the impact on a cost of service study and resulting rate allocation.

<u>RESPONSE TO REQUEST NO. 29</u>: Idaho Power does not have a current proposal regarding how to include demand-side resource incentive payments in a cost-of-service study in a future rate case.

The response to this Request was prepared by Timothy E. Tatum, Manager of Cost of Service, Idaho Power Company, in consultation with Lisa D. Nordstrom, Lead Counsel, Idaho Power Company.