Department of Energy
Washington, DC 20585

February 19, 2009

<u>Via FedEx</u>
Jean Jewell
Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, Idaho 83702

Re: IPC-E-08-10

Dear Ms. Jewell:

Enclosed for filing are the original and seven (7) copies of the Petition for Reconsideration of the United States Department of Energy in the above docket.

Sincerely,

Steven Porter
Assistant General Counsel
For Electricity and Power Marketing
United States Department of Energy

Enclosures
cc: service list via e-mal

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

RECEIVED
2009 FEB 20 AM 10: 11
IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE.	)))))	**CASE NO. IPC-E-08-10**

U.S. DEPARTMENT OF ENERGY'S PETITION FOR RECONSIDERATION

The United States Department of Energy ("the Department" or "DOE"), intervenor, pursuant to Idaho Public Utilities Commission Rule of Procedure 331.01, and Section 61-626 Idaho Code, respectfully petitions the Commission for reconsideration of Order No. 30722, dated January 29, 2009, and issued on January 30, 2009 in Case No. IPC-E-08-10 ("the Order"). The Department requests reconsideration of Order No. 30722 because the cost allocation methodology adopted by the Commission is unreasonable in that it disproportionately allocates steam and hydro generation costs out of Idaho Power's high cost summer months and into low cost non-summer months. Specifically, the Department excepts to the Commission's determination that weighted demand allocators do not produce a reasonable result. Order, p. 35. Upon reconsideration the Commission should adopt the weighted twelve coincident peak method for allocating demand-related costs. This method is consistent with significant efforts by the Company and Commission to reduce Idaho Power's costly summer peak. This Petition is based on the following reasons and upon the following grounds:

I.

A SCHEME ALLOCATING IDAHO POWER'S FIXED STEAM AND HYDRO PRODUCTION PLANT PREDOMINANTLY TO NON-SUMMER, NON-PEAKING, MONTHS SENDS THE WRONG PRICE SIGNAL AND UNDOES THE COMMISSION'S EFFORTS TO REDUCE IDAHO POWER'S SUMMER PEAK

A.

Idaho Power's Capital Investments Are the Driving Force Behind It's Need to File for Rate Increases

Idaho Power's President and Chief Executive Officer, J. LaMont Keen, summarizes the essence of this case when he states, "growing demand for electricity is driving the need to invest large amounts of capital to expand and improve electricity supply and reliability." L. Keen Direct p. 13 at 17. Company witness John R. Gale emphasizes this point when he says, "Idaho Power is experiencing a cycle of heavy infrastructure investment needed to address reliability, customer growth, peak demand growth, and aging plant and equipment." Gale Direct, p. 18 at 17.

B.

It is an Irrefutable Fact that Idaho Power Incurs Its Highest Costs During Its Summer Peak Period

It is well recognized by Idaho Power representatives that its power supply challenges are for the most part related to growing summer peak demands and high power supply costs experienced in the summer months. The Company acknowledges in this case that it is the summer months of June through August that are "the Company's most expensive time to provide power." Company witness Darlene Nemnich, p. 5 at 18. This position is supported by Company witness Timothy Tatum when he describes the recent success Idaho Power has achieved with its

Irrigation Peak Rewards program by saying, "the Company has been successful in reducing load during the summer afternoon hours when costs to provide energy are typically higher." Tatum Direct, p. 12 at 13. That program allows the Company to interrupt irrigation pumps during summer peak conditions in exchange for incentive payments.

It is unsurprising, then, that multiple experts in the current case testified on the importance of focusing on summer peak demands for the purpose of allocating costs to the rate classes. DOE witness Dr. Dennis W. Goins emphasizes this salient point when he said, "the key driver underlying IPC's need for new production resources (both new capacity and expensive purchased power) is peak demand in summer months." Goins Rebuttal, p. 5 at 9. Dr. Don Reading, on behalf of industrial customers, recommends "changes to Idaho Power's COS that brings cost assignments closer the Company's load profile as a capacity constrained utility rather than as an energy constrained utility." Reading Direct, p. 2 at 13. Micon's expert, Dr. Dennis Peseau states that "[p]eaking costs are now driving costs higher for everyone, to the detriment of all," and he concludes that, "[w]e should be looking to adapt our cost of service to recognize these changes, rather than vice versa." Peseau Direct, p. 41 at 17. Anthony Yankel testifying on behalf of the Irrigation class emphasized the importance of and cost savings associated with reducing Idaho Power's summer system peak:

> The Irrigation Peak Rewards Program is about to undergo major improvements that should greatly increase participation levels and become a major resource for Idaho Power to use in controlling its summer peak load. These changes should be in place for next summer's Irrigation season and system peak loads. Any consideration of cost of service and revenue responsibility should reflect the fact that there will be major changes to the system peak loads when these rates are in effect as well as the Irrigation Contribution to those peak loads. Yankel Direct, p. 3 at 14.

Not only are Idaho Power's peak demand costs concentrated in the summer months, its variable power supply costs are also heavily focused in these months. Idaho Power estimated its annual net power supply costs at $88,421,200. Exhibit No. 47, p. 1. Of this amount, Idaho Power estimated that 64 percent of these costs would occur in the summer months, given its estimates of $9,601,900, $26,792,500, and $19,817,000 for the months of June through August, respectively. Id.

C.

It Is an Irrefutable Fact that Idaho Power's Proposed 3CP/12CP Allocators Shift Costs Away from Idaho Power's High Cost Summer Months

Idaho Power's recommended cost of service study abandoned the traditional marginal cost weighted coincident peak allocators used by this Commission in every Idaho Power general rate case over the past twenty-five years to allocate demand-related costs to the rate classes. Dr. Peseau provides a history of marginal cost weighted allocators in his testimony in this case. Peseau Direct, pp. 32-36. These allocators are developed by weighting Idaho Power's monthly coincident peaks by Idaho Power's estimated monthly marginal generation capacity costs and are referred to as weighted twelve coincident peak allocators (W12CP). Instead, Idaho Power recommended a cost allocation scheme that uses the twelve monthly coincident peaks (12CP) without marginal cost weightings to allocate its demand-related steam and hydro costs, which represent the large majority of its demand-related production costs, and the three summer coincident peaks (3CP) to allocate the small portion of its demand-related production costs associated with its combustion turbines. Idaho Power refers to its use of these allocators as its 3CP/12CP study.

It goes without saying that Idaho Power and this Commission place significant weight on determining the costs properly allocable to the summer months of June through

August. Sending cost-based price signals to all classes of customers during summer months will result in lower long-term costs for all customers as a whole because price induced conservation will lead to lower fuel and capital costs. Cost-based price signals will also lead to efficiently designed demand-side programs that compliment price induced conservation. Given that Idaho Power's production plant represents the largest of Idaho Power's fixed plant-related costs, the selection of allocators for demand-related production costs is a major cost allocation and rate design decision. It will directly influence the success or failure of the Company's rate design in sending cost-based price signals to customers and the success or failure of any demand-side management programs focused primarily on summer consumption.

The different allocators at issue in this case place markedly different levels of costs into the summer period. Idaho Power proposed to allocate 100 percent of demand-related combustion turbine costs to the summer months using a 3CP allocator. Idaho Power's selection of a 12CP allocator for its demand-related steam and hydro costs is at the opposite end of the spectrum with only a 30 percent weight given to summer months. Also presented in this case was a W12CP allocator that allocates over 58 percent of costs to the summer months. Exhibit No. 59. Finally, a hybrid allocator calculated as the average of the W12CP and 12CP allocators (hereinafter referred to as the half-weighted 12CP or "HW12CP" allocator) was presented and it allocates 44 percent of costs to the summer months. Id.

Only the Irrigation class benefits from the Company's proposed 3CP/12CP allocators; all other rate classes are negatively affected. The Irrigation class's cost-based revenue requirement allocation decreases by 4.3 percent.[1] In stark contrast to this result, the Traffic Control class receives a 10.5 percent increase in allocated costs. DOE's cost-based revenue

[1] See Exhibit Nos. 66 and 61. As an example, the cost-based revenue requirement for the Irrigation class falls to $99,033,080 (Exhibit No. 66) from $103,447,573 (Exhibit No. 61), or 4.3 percent.

requirement allocation increases by 2.9 percent, and the other rate classes receive less significant increases. A true understanding of the net result of these cost allocation changes can only be gained by understanding the seasonal coincident peaks of the rate classes. The Irrigation class's summer coincident peaks total 62 percent of the sum of its twelve coincident peaks, which is an indication of the concentration of this class's peaks in Idaho Power's high cost summer months. Exhibit No. 59. This relative level of summer usage is extraordinary given the fact that the rate class with next highest concentration of coincident peaks in the summer months, the General Service rate class, has a concentration of less than 30 percent, or less than half that of the Irrigation class. Id. Finally, this comparison of studies leads to an irrefutable conclusion: Idaho Power's proposed 3CP/12CP allocators shift costs away from Idaho Power's high cost summer months.

This same conclusion was independently reached by Dr. Peseau. He concludes that:

> [T]he 12CP method is completely inappropriate for a strongly peaking utility like Idaho Power. Furthermore, it is disingenuous for Mr. Tatum to lament the rapid growth in the spikiness of summer peak demand, when his preferred cost of service study maximizes the amount of summer peak costs pushed out of the summer peak period into off peak seasons. We can see this very clearly in the ultimate results of his 3CP/12CP study, which in fact shifts more costs off peak than the flawed modified base case I described earlier. In short, Mr. Tatum is headed in precisely the wrong direction. Peseau Direct, p. 44 at 1.

D.

The Company's and the Commission Staff's Arguments in Favor of Using a 12CP Allocator for Idaho Power's Demand-Related Steam and Hydro Costs Are Illogical and Do Not Comport with the Facts

The Company's justification for a significant change in cost allocation methods from the 2003 Case is limited at best. Company witness Tatum states Idaho Power's position that "[u]sing an un-weighted 12CP allocator is more appropriate in this case given that fixed base and intermediate generation costs do not vary greatly between the summer and non-summer seasons." Tatum Direct, p. 20 at 19. These are the same generating units with the same general cost profile as those before the Commission in the 2003 Case, so the material facts did not change—just the Company's view of summer versus non-summer cost allocations for these units. The Commission notes in its Order that "[t]he Company asserted that the 3CP/12CP method is an improvement over the prior W12CP method and that it will more adequately assign base and intermediate costs to the rate classes." Order, p. 32. As noted above, Idaho Power's 12CP allocation factor leads to a grossly inaccurate assignment of costs because there is no recognition of high seasonal summer capacity costs, which would be the case with a W12CP allocator. It is inconsistent with twenty-five years of precedent and absurdly encourages peak usage!

In arguing for the use of a 12CP allocator to assign fixed production costs for steam and hydro resources to the rate classes, Staff witness Hessing testifies that:

> Capacity is required and has value in all months. Idaho Power is a dual peaking utility with a summer and winter peak. The off peak, spring and fall shoulder months, provide the opportunity for the Company to take plants down for necessary scheduled maintenance. This circumstance can produce situations in shoulder months where available capacity is as important as it is in peak load months. Hessing Rebuttal, p. 14 at 10.

Idaho Power is not a dual peaking utility. Nor is available capacity in shoulder months as important as it is in peak load months. It is and will continue to be a summer peaking utility, and the concentration of Idaho Power's marginal generation capacity costs in the summer months confirms this. Further, Staff's position is clearly inconsistent with Company, Staff, and Commission positions taken in the Irrigation Peak Rewards program.

Company witness Tatum makes another attempt to justify using a 12CP allocator for Idaho Power's demand-related steam and hydro plant in his testimony when he states:

> Of the three studies, the 3CP /12CP study applies an approach that results in the most equitable allocation of costs to customer classes. Each study was prepared with the same goal of allocating costs to customer classes according to the cost impact that each class imposes on the utility system. However, the 3CP/12CP study applies a cost-of-service methodology that best reflects the ways in which costs are currently imposed on the Company's system. For example, over the last six years, Idaho Power has added four combustion turbine generation units to serve summer peak loads. Because the costs associated with these new units are driven primarily by summer loads, it is appropriate to allocate the cost of those new resources according to each class's contribution to the summer peak loads. However, production plant costs associated with serving the base and intermediate loads are driven more by the monthly peaks throughout the entire year. By separating the production plant into the two categories, the generation costs can be allocated according to the most appropriate cost driver. Tatum Direct, p. 51 at 8.

He is unequivocal that combustion turbines are used to meet peak loads and the costs of combustion turbines should be allocated to each class's contribution to summer peak loads. This was not the subject of any significant disagreement in this case. He is far from unequivocal when he states that, "production plant costs associated with serving the base and intermediate loads are driven <u>more</u> by the monthly peaks throughout the entire year." Id. (Emphasis added.) For twenty-five years this Commission has concluded that production plant costs associated with serving base and intermediate loads are driven <u>more</u> by coincident peaks in months with marginal capacity costs and, to a lesser extent, with coincident peaks in all other months. Idaho Power's new found costing methodology conflicts with all prior Commission rulings on this issue.

Mr. Tatum seems to imply that Idaho Power's recent additions of combustion turbines into its power supply portfolio has changed the nature of how it operates its steam and hydro units compared with past general rate cases. This cannot possibly be true. Idaho Power's estimated normalized net power supply indicates that combustion turbines will combine to produce only 1.3 percent of Idaho Power's peak month energy supply in July, and less than one-quarter of one percent of Idaho Power's annual energy supply.[2] The additions of these combustion turbines could not therefore have had a material effect on Idaho Power's operation of its steam and hydro units. Certainly not sufficient enough to conclude that cost allocators should change dramatically for Idaho Power's steam and hydro units and in the direction of allocating costs away from the summer months.

Company witness Said confirms that Idaho Power's steam and hydro units, and purchased power, play a prominent if not the primary role in meeting Idaho Power's peak demands when he states, "Danskin and Bennett Mountain, as peaking plants, operate intermittently, but offer significant contribution at important times <u>when resources and purchases are inadequate to serve peak loads</u>." Said Direct, p. 12 at 18. (Emphasis added.) Clearly, Mr. Said is referring to Idaho Power's steam and hydro units when he is referring to its "resources." Also, Mr. Said implies that peaking units are used only after steam and hydro units, and purchases, are dispatched. This suggests that Idaho Power's combustion turbines act importantly

[2] See Exhibit No. 47, p. 1. Danskin and Bennett Mountain combined for 21,504 MWh of generation compared with 1,639,561 MWh of total production and purchased power, excluding surplus sales. On an annual basis these numbers are approximately 42,000 MWh of natural gas-fired generation versus 17,200,000 MWh of total generation and purchased power, excluding surplus sales.

as reserve capacity that can be called upon when needed, on extremely hot days or in the event of forced outages, but that Idaho Power's steam and hydro units, and purchases, are the primary resources used to meet peak demands, including peak demands during the summer months.

The Commission should reject the use of the 12CP allocator used by Idaho Power to allocate Idaho Power's demand-related steam and hydro costs given the lack of empirical support for this allocator in this case.

E.

Upon Reconsideration, The Commission Should Set Rates that Are Consistent with the Commission's Efforts to Reduce Peak Demand

This Commission should set rates based on cost for two key reasons, fairness and efficiency, as described by Micron witness Peseau. He explains that fairness "basically refers to the idea that customers should pay their own costs and not someone else's." Peseau Direct, p. 30 at 3. He explains the efficiency rationale as follows:

> This is the idea that prices should promote the most efficient possible use of the utility system. Thus, those who use the system primarily when costs are high should pay a rate that reflects those disproportionately high costs so they will be encouraged to conserve or find alternative means of meeting their needs. And there is an important, but out of favor, counterpoint here as well. Those who consume in low cost periods should receive an appropriate price signal to do so when consumption is an economic plus for all. Peseau Direct, p. 30 at 7.

Efficient use of Idaho Power's resources is of significant enough concern that its chief executive addressed this issue in his testimony in this case. Mr. Keen explains Idaho Power's strategy for addressing load growth trends when he says:

> We are addressing them on both the supply-side and demand-side of the equation. In addition to expanding our production delivery systems, we are aggressively promoting demand-side management

> programs and services. These energy efficiency efforts serve to slow the pace of growth in a cost-effective manner by delaying the need for additional generating resources. Additionally, these efforts educate our customers on wise, responsible use of our precious resource. Keen Direct, p. 5 at 22.

The importance of efficient rate design was also emphasized by Company witness Gale in his testimony where he says:

> I have directed the three pricing analysts sponsoring testimony in this case to design cost-based rate proposals that encourage increased energy efficiency among the Company's Residential, Large General Service, and Irrigation customer groups. Gale Direct, p. 26 at 5.

The implications of artificially lowering summer rates through cost allocation are many. First, demand side management programs espoused by Idaho Power's chief executive will fall short of their potential. Second, peak usage will be higher than it otherwise would be, leading to ever-increasing capital investments in infrastructure that are so prominently discussed in this case.

Dr. Peseau explains the concerns:

> In allocating summer peak capacity and energy costs to off peak seasons, rates for summer usage will be too low, and rates for non-summer usage will be too high. But this problem does not balance out. The reason it does not balance out is that the underpricing of summer usage will promote more summer usage and require Idaho Power to invest more heavily than otherwise in new peaking facilities and DSM programs. The Company of course earns a return on these programs but, as a result, all ratepayers' rates are higher. Peseau Direct, p. 44 at 11.

Dr. Goins also emphasizes the negative consequences of reliance on costing methodologies that produce a result that clearly is absurd when he states, "if you base your prices on those ludicrous results...your peak pricing will be wrong, your development of off-peak loads is wrong, is ineffective, and your encouragement of people to use electricity more efficiently is wrong." Tr. p. 986 at 6. Use of Idaho Power's 3CP/12CP study produces the absurd result to which Dr. Goins refers. It clearly is a costing methodology that should not be adopted by this Commission because it moves costs away from the periods that are of the greatest concern to the Company and this Commission in terms of lowering Idaho Power's overall costs and capital requirements, and maximizing the energy conservation benefits of demand-side management programs and time-of-use pricing. If anything, the Commission needs to move in the opposite direction of that suggested by the 3CP/12CP study.

Idaho Power's 3CP/12CP study will not, based on the record of evidence in this case, produce rates that are consistent with the Commission's efforts to reduce peak demands. It should therefore be rejected. In its place, the Commission should adopt changes to Idaho Power's cost study that promote economically efficient use of Idaho Power's resources.

II.

NATURE AND EXTENT OF EVIDENCE AND ARGUMENT TO BE OFFERED ON RECONSIDERATION

Commission Rule of Procedure 331.01 requires that DOE state the nature and extent of evidence or argument it will present or offer if reconsideration is granted. It is the position of DOE that the evidentiary record before the Commission and the applicable law requires that the Commission modify Order No. 30722 as set forth in this Petition For Reconsideration. Additional evidence set out below, taken from sworn Company testimony from prior cases, supports the foundation of this Petition:

1) Idaho Power is a summer peaking utility, not a dual peaking utility;
2) Idaho Power is capacity-constrained over the next several years, particularly in the summer months;
3) Idaho Power's costs are the highest in the summer months; and

4) the Commission and Company, along with Staff and other parties, are working together to save costs by lowering Idaho Power's summer peak demand.

A.

Idaho Power is A Summer Peaking Utility, Not a Dual Peaking Utility

The Commission has adopted the position that Idaho Power's costs are driven in large part by summer peak demands in the Irrigation Peak Rewards program case, Case No. IPC-E-08-23. In that case, the Commission relied upon Idaho Power representations that the Company places great value on reducing peak demands. In its Order No. 30717, the Commission describes a program change it approved that shortened the Irrigation Peak Rewards program interruption period from June 1 through August 31, or three months, to a six-week period of June 15 to July 31:

> The time period was shortened because the value of the load reduction capability of the program is its ability to reduce loads when the demand on the electrical system is at or near the annual system peak. Idaho Power's witness testified that currently there is a near zero probability that Idaho Power s electrical system will experience a annual system peak demand outside of the time period of June 15 through July 31. Order No. 30717, pp. 3-4.

The full text of Company witness Tatum's testimony is as follows:

> As part of the research and analysis process that led to the proposed Program design, the internal Program design team at Idaho Power held several discussions with subject matter experts that work within the generation dispatch and power supply planning functions of the Company. According to perspectives shared by representatives from the generation dispatch and power supply planning groups, the value of the load reduction capability of the Program is in its ability to reduce loads when the demand on the electrical system is at or near the annual system peak.

> Furthermore, these discussions confirmed that currently there is a near zero probability that Idaho Power's electrical system will experience a annual system peak demand outside of the time period of June 15 through July 31. With that in mind, the Program Season was revised to align with the June 15 through July 31 period. Tatum Direct, Case No. IPC-E-08-23, pp. 14-15.

The Company unequivocally stated that, "there is a near zero probability that Idaho Power s electrical system will experience a annual system peak demand outside of the time period of June 15 through July 31." The Commission Staff was a party to the stipulation approved by the Commission in that case and did not voice any disagreement with the position that Idaho Power's system peak demands are likely to occur during a very short six-week period in the summer. The Commission supported this decision. Clearly, this contradicts Staff witness Hessing's statement that Idaho Power is a "dual peaking utility," which Mr. Hessing used to justify his support for Idaho Power's use of a 12CP allocator. Hessing Rebuttal, p. 14 at 10.

B.

<u>Idaho Power is Capacity-Constrained Over the Next Several Years, Particularly in the Summer Months</u>

Case No. IPC-E-08-21 is an application by Idaho Power for approval of a special contract to supply power to Hoku Materials, Inc. ("Hoku"). Hoku is a new customer that requires 82 megawatts ("MW") of capacity. Idaho Power has agreed to serve Hoku, but has not agreed to provide the full 82 MW requested by the customer. Idaho Power's position was explained by Company witness Gale when he states, "Because of supply and transmission constraints, Idaho Power was unable to serve at this level during certain summer months prior to 2012." Gale Direct, p. 7 at 5. Idaho Power has only agreed to provide Hoku with 43 MW for the years 2010 and 2011 during the abbreviated summer period of June 16th and August 15th.[3] This contract provides additional evidence that Idaho Power is capacity-constrained in the summer months, and not in other months of the year, which supports demand-related cost allocations primarily in the summer months. It also highlights the importance of efforts to reduce Idaho Power's peak demand in the coming years. Company witness Gale testifies that, "there is a contingency provision that reduces the Company's 2012 capacity obligation in case Idaho Power is not able to add additional generation and/or transmission as planned." Gale Direct, p. 7 at 15. This statement confirms that Idaho Power must make capital investments to relieve its capacity-constrained system, which again points to the need for proper cost allocation to the summer months.

C.

Idaho Power's Cost Are the Highest in the Summer Months

Idaho Power has consistently taken the position that its costs are the highest in the summer months. However, its cost studies are in direct contradiction with these statements. Testimony sponsored by the Company in the last case confirms the concentration of high costs in the summer months. Brilz Direct, 2003 Case, p. 26 at 12. In that case, Ms. Brilz also stated that:

> Besides being more costly during the summer months, energy is more costly during certain hours of the day. The implementation of time-of-use rates for Schedule 19 customers, who currently have the metering in place to accommodate the hourly pricing, will provide the economic signal that energy is more costly during the peak hours of the day and the peak months of the year. Again, like strictly seasonal rates, it is hoped that time-of-use rates will encourage reduced consumption both during the summer months as well as during the daily peak hours. Brilz Direct, 2003 Case, p. 27 at 9.

[3] Section 6.1.1, "Scheduled Contract Demand," in the Electric Service Agreement included in Idaho Power's application as Attachment 1.

D.

The Commission and Company, Along with Staff and Other Parties Are Working Together to Save Costs by Lowering Idaho Power's Summer Peak Demand

Case No. IPC-E-08-23, Idaho Power's Peak Rewards Program case is an excellent example of the Commission and Company working together to increase Idaho Power's peak shaving programs. In that case, Idaho Power explicitly linked the credits provided to irrigation customers that reduce their peak demands to Idaho Power's rates for the Irrigation class. This provides an indication of the important role rates have on the effectiveness of demand-side programs. Company witness Tatum describes the Company's rationale for maintaining this relationship:

> Since the inception of the Program, the Company has maintained that it is important that the Demand Credit amount remain below the Demand Charge under Schedule 24, Agricultural Irrigation Service. This ensures that customers participating in the Program are not incented to turn on a pump when they otherwise would not simply to earn a bill credit. The proposed incentive structure recognizes that notion by including an energy-based incentive amount which allows for additional incentive dollars to be provided to participating customers while maintaining a Demand Credit at or below the current Demand Charge under Schedule 24. Tatum Direct, Case No. IPC-E-08-23, p. 17 at 4.

III.

CONCLUSION AND REQUEST FOR RELIEF

The Commission, like other state regulatory bodies across the nation, faces significant challenges as the country undergoes a transformation of the electric utility system. Clearly, the Commission understands the import of sending proper price signals to effect customer behavior designed to lower peak demands and reduce the need for expensive generation. Indeed, the Commission, as noted, has approved the irrigation peak reduction program. In this case, it has adopted rate-design reflecting the higher cost of summer power. And soon, the Commission will consider approving collection of millions of ratepayer dollars for DSM and energy efficiency programs. States, utilities and private companies will soon team-up with the Department to invest billions of dollars in smart grid activities. But DSM programs, smart grid pricing information and energy efficiency efforts are ineffective if the value of summer power is artificially lowered through cost allocation methods. It is essential that regulatory price signals be consistent. It is illogical to, on one hand, adopt policies and programs designed to conserve energy and reduce summer peak usage while, at the same time, arbitrarily reducing the cost of summer peak power.

The most logical and straightforward step this Commission could take based on the record of evidence in this case to promote economically efficient rates, cost-effective demand-side management programs, efficient capital investment, and lower overall costs for Idaho Power's customers, is to order that a W12CP allocator be used in place of the 12CP allocator proposed by the Company for the allocation of demand-related production costs. The adoption of a W12CP allocator is logical because it provides a direct link between Idaho Power's high summer marginal capacity costs and the allocation of costs to the customer classes, particularly those classes that record high peak demands during Idaho Power's high cost summer months. This change is straightforward because the W12CP allocator is easily calculated from the record in this case and can easily be inserted into the Company's cost of service study.

DOE suggests that the Commission order the Company and Staff to hold cost-of-service workshops to further investigate and discuss other cost-of-service issues raised by the parties in this case. These issues were many and are important to the proper allocation of costs to the summer and non-summer months. In addition, these workshops should simultaneously address how cost of service methodologies can support effective demand-side programs, particularly peak shaving programs.

Finally, DOE believes that it would be appropriate to employ the six percent cap on rate increases adopted by the Commission in its Order. In so doing, the reconsideration of these critical costing methodology issues can be undertaken without producing a result that will dramatically affect customer rates.

DATED at Washington, D.C., this 19th day of February, 2009.

Respectfully Submitted,

Steven A. Porter
Assistant General Counsel
U.S. Department of Energy
1000 Independence Ave., SW
Washington, D.C. 20585
Telephone: (202) 586-4219
steven.porter@hq.doe.gov

Certificate of Service

I HEREBY CERTIFY that I have this day of February 19, 2009, served the foregoing Petition for Reconsideration in Docket No. IPC-E-08-10 upon the Secretary of the Commission by FedEx and on the following parties in this proceeding by electronic filing.

Barton Kline
Lisa D. Nordstrom
Donovan E. Walker
Idaho Power Company
1221 W. Idaho St.
PO Box 70
Boise, ID 83707-0070

John R. Gale
Idaho Power Company
1221 W. Idaho St.
PO Box 70
Boise, ID 83707-0070

Weldon Stutzman
Neil Price
Deputy Attorneys General
Idaho Public Utilities Commission
472 W. Washington
PO Box 83720
Boise, ID 83720-0074

Peter Richardson, Esq.
Richardson and O'Leary
515 N. 27th St.
PO Box 7218
Boise, ID 83702

Dr. Don Reading
Ben Johnson Associates
6070 Hill Road
Boise, ID 83703

Randall C. Budge
Eric L. Olsen
Racine, Olson, Nye, Budge & Bailey, Chartered
201 E. Center
PO Box 1391

Pocatello, ID 83204-1391

Anthony Yankel
Yankel & Associates, Inc.
29814 Like Road
Bay Village, OH 44140

Michael Kurtz, Esq.
Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 1510
Cincinnati, OH 45202

Kevin Higgins
Energy Strategies, LLC
Parkside Towers
215 S. State Street, Suite 200
Salt Lake City, UT 84111

Conley E. Ward
Michael C. Creamer
Givens Pursley, LLP
601 West Bannock Street
PO Box 2720
Boise, ID 83701-2720

Dennis E. Peseau, Ph.D.
Utility Resources Inc,
1500 Liberty Street, SE, Suite 250
Salem, OR 97302

Brad M. Purdy
Attorney at Law
2019 N. 17th St.
Boise, ID 83702

Ken Miller
Snake River Alliance
PO Box 1731
Boise, ID 83701

Steven Porter
Assistant General Counsel
United States Department of Energy