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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

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DARLENE NEMNICH

Q. Please state your name and business address.

A. My name is Darlene Nemnich. My business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Senior Regulatory Affairs Analyst.

Q. Please describe your educational background.

A. In May of 1979, I received a Bachelor of Arts degree in Business Administration with emphases in Finance and Economics from the College of Idaho in Caldwell, Idaho. In addition, I have attended the electric utility ratemaking course offered through New Mexico State University's Center for Public Utilities as well as various other ratemaking courses sponsored by the Edison Electric Institute.

Q. Please describe your business experience with Idaho Power.

A. In 1982, I was hired as an analyst in the Resource Planning Department. My primary duties were the calculation of avoided costs for cogeneration and small power production contracts and the calculation of costs of future generation resource options. In 1989, I moved to the Energy Services Department where I performed economic, financial, and statistical analyses to determine the cost-effectiveness of demand-side management programs. I stayed in that general area designing, implementing, and evaluating programs until 2000, when I was promoted to Energy Efficiency Coordinator. In that capacity, I coordinated the Company's effort to expand customer programs and education in energy efficiency. I was responsible for complying with regulatory and financial requirements in the area of energy efficiency. In 2003, I was promoted to Energy Efficiency Leader where I managed the Company's demand-side management efforts, including strategic planning, design and development of programs, regulatory compliance, and overall management of the department.

In 2006, I left the Company to pursue personal opportunities but returned to the Company as a Senior Regulatory Affairs Analyst in the Regulatory Affairs Department in April 2008. My duties as Senior Regulatory Affairs Analyst include the development of alternative pricing structures, analysis of the impact on customers of rate design changes, providing regulatory assistance in the area of demand-side management, and the administration of the Company's tariffs.

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

A. My testimony will address two areas: (1) the Company's proposal for changes in how demand response incentive costs are recovered and (2) the Company's proposal for changes in how some of the energy efficiency incentive costs are recovered.

Q. How does your testimony tie to Mr. Gale's testimony?

A. Mr. Gale's testimony provides a comprehensive policy discussion on the subject of demand-side resources ("DSR"). The two proposals contained in my testimony are intended to support the implementation of two parts of the Company's overall plan as described by Mr. Gale.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 1, *Energy Efficiency Rider Account Projections*.

Q. Please describe the Company's proposal for changes in how demand response incentive costs are recovered.

A. Currently, all Idaho demand response program costs are recovered through the Energy Efficiency Rider ("Rider") balancing account, Idaho Rate Schedule 91. The

Company is proposing to move the recovery of some of those costs to the Power Cost Adjustment ("PCA") mechanism.

Q. What demand response programs have been implemented by the Company as part of its overall DSR portfolio?

A. Idaho Power currently manages three demand response programs. The A/C Cool Credit program provides summer peak reduction benefits by cycling participating residential customers' air-conditioning units. This program began in 2003. The Irrigation Peak Rewards program began in 2004 and switches off participating customers' irrigation pumps during times when additional system peak resources are needed. The most recently implemented demand response program, FlexPeak Management, began in 2009 and reduces commercial and industrial load when called upon during system peak times.

Q. How does the Company determine the amount of demand response resources to acquire?

A. The overall amount and timing of demand response resources the Company acquires is determined through the development of the Integrated Resource Plan ("IRP"). The IRP identifies when new peak resources are needed due to increased load. Options to meet that peak capacity requirement, whether from new peaking plants or new demand response programs, are evaluated and the least-cost option that best fits the need is selected.

Q. How many megawatts ("MW") of peak demand did these programs contribute to offset system peak needs in recent history?

A. In 2009, the three programs provided 218 MW of resources available to meet system peak needs. In 2010, preliminary estimates indicate that these programs reduced peak by approximately 290 MW.

Q. Have the demand response programs supplied the Company a consistent and reliable resource similar to other peaking resources?

A. Yes. System dispatchers use demand response resources to meet system needs alongside traditional supply-side means of meeting system peak requirements, like a gas-fired simple cycle combustion turbine or wholesale energy purchases. For the past several years at the beginning of each summer peak season, Company system dispatchers and demand resource program managers have reviewed the total demand response resource available and the general operating parameters of each program for the year. Then, each week of the summer season, system resource dispatchers are given the amount of demand response resource, in megawatts of peak reduction, which will be available for dispatch that week.

Q. Given the characteristics you have described for the demand response resources, why is it appropriate to include them in the PCA mechanism?

A. Demand response programs have become a significant and mature resource for reducing the varying summer peaking needs on the Idaho Power system. Demand response resources are selected similar to other generating resources in the IRP, and most importantly, this resource is dispatched by system operators just like any other peaking resource used by the Company. Starting with the 2009 IRP, demand response resources were included in the Power Supply Planning model, AURORAxmp.

Q. Currently, how are demand response program costs recovered?

A. All costs for the demand response programs are recovered through the Rider. Currently, the Idaho Rider charge is 4.75 percent of base rates applied to all customer groups. Idaho Power tracks the costs of its demand response programs by program and expense type. These cost categories include incentives, administrative costs, materials and equipment, marketing costs, labor, and evaluation.

Q. What categories of costs is the Company proposing to be recovered through the PCA mechanism?

A. The Company proposes that the costs which would most appropriately be recovered through the PCA are the direct incentive costs paid either to customers for demand reduction or to demand-aggregator contractors for demand reduction. Incentive costs more closely represent the variable cost used to acquire a peak resource during a peak shortage.

Q. Why not move all demand response program costs out of the Rider and into the PCA?

A. The PCA typically recovers variances in net power supply expenses. These expenses, which include fuel, purchased power, and surplus sales, vary over the course of the year as the Company responds to meeting system load requirements. Generally, demand response program costs, other than those associated with direct incentive costs, do not vary with the dispatching of this peak resource and therefore could be categorized as fixed costs. That is why the Company has chosen to propose to move only demand response incentive costs to the PCA.

Q. Are you proposing to shift costs incurred in 2010?

A. No. Idaho Power is proposing that all 2010 actual program costs, even the demand response incentive costs for reduced load for the summer peak season, continue to be recovered through the Rider. Idaho Power's proposal is to begin shifting the recovery of the demand response incentive costs to the PCA beginning with the Company's forecast of April 2011 through March 2012 power supply costs.

Q. What will be the amount of forecasted demand response incentive costs included in the 2011 PCA?

A. It is premature to know the exact amount of the demand response incentive costs to be included in the 2011 PCA. However, current estimates of the 2011 demand response incentive costs based upon the current structure of the three programs would be approximately $13.7 million. This estimate would be refined next spring as summer loads and resource needs are reevaluated.

Q. How do you propose to include the forecasted demand response incentive costs in the 2011 PCA?

A. Idaho Power proposes to include these costs in the PCA in a manner that is consistent with the current PCA methodology. The Company would forecast demand response incentive payments just as it does for its forecast of fuel, purchased power, and surplus sales. This forecasted amount of demand response incentive costs would be included in PCA rates, effective June 1, 2011.

Q. Does the Company intend to establish a base level of demand response incentive cost recovery in base rates just like other power supply costs?

A. Yes, but not at this time. As part of a future filing, it would make sense for the Company to include a normal or base level of demand response incentive expenses in base rates just like other supply-side peaking resources. Then annually, as part of the PCA case, the forecasted level of incentive payment expenses would 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. Any deviations between actual demand response incentive costs and forecasted costs would be included in the following year's PCA true-up.

Q. How would demand response costs be allocated?

A. Idaho Power proposes to allocate 100 percent of the Idaho incentive payment costs to the Idaho jurisdiction in the PCA. This is no different from the current recovery of demand response incentive costs through the Rider where Idaho customers are paying for 100 percent of the demand response incentives incurred by Idaho customers. It is logical that if the recovery of those costs is moved from the Rider to the PCA, that the jurisdictional assignment of those costs remains consistent.

Q. Do you propose that 100 percent of the demand response incentive payments be recovered in the PCA?

A. Yes. Because 100 percent of these demand response costs are currently being recovered in the Rider, recovering 100 percent of these costs in the PCA would be consistent. To do otherwise would force Idaho Power to take a financial loss on its pursuit of demand response as a resource.

Q. Do any other utilities have their demand response program incentive costs recovered outside of an energy efficiency rider?

A. Yes. Rocky Mountain Power does not recover their Idaho irrigation load control program incentive amounts from their energy efficiency rider account. Those amounts are currently recovered through Idaho base rates. Also, costs from Portland General Electric's current demand response pilot are tracked in a deferred account and PGE requested these amounts be transferred to their PCA at the end of the pilot.

Q. Please describe the Company's second proposal that would change the method of recovery for a portion of energy efficiency program incentive payments.

A. In addition to moving demand response incentive costs to the PCA, Idaho Power is proposing to change the method of recovering a portion of the energy efficiency program incentive costs. Currently, all energy efficiency incentive costs are recovered through the Rider balancing account. As explained in Mr. Gale's testimony, the Company is proposing to capitalize the 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 direct incentive payments for the Custom Efficiency program 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. The then current Commission authorized rate of return would be applied as a carrying charge during the deferral period and the amortization period. This treatment will keep the selected demand-side resource assets on par with Company investments in supply-side assets.

Q. Please describe the Custom Efficiency program and explain why it was selected for capitalization.

A. The Custom Efficiency program is a mature program that started in 2003 and has grown into the Company's largest program in terms of megawatt-hour ("MWh") savings. Each customer project within the Custom Efficiency program is thoroughly reviewed to ensure that energy savings are achieved. The energy savings are calculated by Idaho Power engineering staff or a third-party consultant. The verification process requires that end-use measure information is collected. On many projects, and especially the larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process ensures achievement of projected energy savings. Additionally, this program historically is one of the most cost-effective programs in the Idaho Power portfolio. As shown on page 43 of Supplement 1 of the *Demand-Side Management 2009 Annual Report* filed in Case No. IPC-E-10-09, from a Total Resource Cost ("TRC") perspective, the 2009 TRC benefit/cost ratio was 3.56. If analyzed over the life of the program, the TRC benefits are more than twice the costs. The program maturity, the high benefit/cost ratios, and the detailed verification process were major factors in the selection of this program for cost deferral and capitalization.

Q. How many megawatt-hours did this program save in recent history?

A. In 2008 and 2009, the Custom Efficiency program saved 41,059 and 51,836 MWhs, respectively. In 2009, this represented almost 40 percent of the total MWh savings on a system-wide basis for energy efficiency programs implemented by Idaho Power.

Q. Please explain the current method of tracking energy efficiency incentive costs.

A. As mentioned earlier, costs for the energy efficiency programs are recovered the same as the demand response programs – through the Idaho Rider. Idaho Power tracks the costs of its energy efficiency programs by program and expense type. These cost categories include incentives, administrative costs, materials and equipment, marketing costs, labor, and evaluation.

Q. Which cost categories does the Company propose be capitalized?

A. The costs which would most appropriately be capitalized are the direct incentive costs paid to customers for energy efficiency measures. The majority of payments made for direct incentives are for tangible equipment in customer facilities. This equipment can be viewed as similar to physical plant except it is not owned by the Company; it is owned by the customer.

Q. When these costs are placed into rate base, how would the Company allocate energy efficiency incentive costs?

A. Idaho Power proposes to allocate 100 percent of the Idaho incentive payment costs to the Idaho jurisdiction. Currently, Idaho customers are paying for the energy efficiency program incentives incurred by Idaho customers. It is logical that if the recovery of those costs is moved from the Rider into a regulatory asset account that is capitalized, that the jurisdictional assignment of those costs remains consistent.

Q. What is the current balance in the Energy Efficiency Rider balancing account?

A. As of the end of September the Rider account balance was $16,688,002.

Q. Have you estimated what the Rider balance would be if neither of the Company's proposals are approved by the Commission?

A. Yes. Exhibit No. 1, Table 1, shows a three-year forecast of the Rider balance with revenues at current rates and with the current forecast of demand-side resource expenditures. The estimated 2010 year-end negative balance of $17,009,140 increases to a negative $29,677,151 in 2012.

Q. How did you arrive at this estimate?

A. I used the same revenues that were used in compliance filings made June 1, 2010, with the Idaho Public Utilities Commission pursuant to Order Nos. 31091, 31093, and 31097. Then I applied the current Rider percent of 4.75 to calculate Rider revenues. All DSR expenditures are from current forecasted estimates. For 2010, I used January-August actual values and forecasted values for September-December.

Q. If approved by the Commission, how will implementing the Company's two proposals affect the forecasted balance of the Rider?

A. Table 2 of Exhibit No. 1 reflects the impact of the two proposals and shows that the 2010 negative Rider balance of $17,009,140 would be reduced to a negative $3,356,306 in 2011. If the current forecasted revenues and expenses hold true, it is expected that this account will approach zero sometime in the middle of the year 2012.

Q. How did you arrive at these estimates?

A. To arrive at these numbers, I started with Table 1, described above. For 2011 and 2012, I subtracted the forecasted incentive costs for demand response programs of $13,753,335 and $14,537,368, respectively, in the row labeled *Less DR Incentives.* These forecasted values are the estimates of demand response incentives that would be transferred to the PCA mechanism. I also subtracted out the forecasted incentive costs for the Custom Efficiency energy efficiency program of $5,193,650 in 2011 and $5,565,480 in 2012 in the row labeled *Less EE Incentives*. These forecasted values are the estimates of incentive costs for the Custom Efficiency program that would be transferred to a regulatory asset account for capitalization. Only the actual incentive payments made to customers would be included in the regulatory asset account.

Q. Have you calculated the Rider percent necessary to take the Rider account balance to zero absent Commission approval of the two Company proposals?

A. Yes. 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.

Q. If the Commission adopts these proposals, would it change the ability of the Commission and its staff to review incentive costs for prudency?

A. No. Demand response incentive costs would be reviewed along with power supply expenses and market transactions as part of the PCA review process between April 15 and June 1 of each year. However, unlike other PCA costs, the prior year's costs will be available for review earlier because they will be included in the *Demand-Side Management Annual Report* filed March 15.

Energy efficiency incentive costs can be reviewed during the annual prudency review filed by the Company.

Q. Why are you proposing these changes at this time?

A. With regard to the first proposal to move demand response incentive costs to the PCA, Idaho Power is filing for this change now in order to provide the Commission ample time for deliberation and review prior to the annual spring PCA filing. If the Commission agrees to this proposal, Idaho Power will be able to include these changes in the April 15, 2011 PCA filing. With regard to the second proposal, with a Commission order allowing creation of a deferral account, the Company will be able to begin deferring the appropriate energy efficiency incentives as of January 1, 2011.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-27

IDAHO POWER COMPANY

NEMNICH, DI
TESTIMONY

EXHIBIT NO. 1

Idaho Power Company
Energy Efficiency Rider Account Projections

Table 1
Projected Year-End Energy Efficiency Rider Account Balances
Expected Expenditures
2010-2012

	Actuals (Jan-Aug) Forecast (Sep-Dec) 2010	Forecast 2011	Forecast 2012
Calculation of Rider Revenues			
Estimated Total Revenues		$801,868,308	$801,868,308
Idaho Rider Percent		4.75%	4.75%
Idaho Rider Revenue (1)	$34,976,990	$38,088,745	$38,088,745
Calculation of Rider Balance			
Beginning Balance	($9,718,518)	($17,009,140)	($22,303,290)
Revenue(1)	$34,976,990	$38,088,745	$38,088,745
Total Expenses(2)	($42,267,612)	($43,382,895)	($45,462,605)
Ending Balance	($17,009,140)	($22,303,290)	($29,677,151)

Table 2
Projected Year-End Energy Efficiency Rider Account Balances
With DR incentives to PCA and EE Incentives to Deferred Account
2010-2012

	2010	2011	2012
Calculation of Rider Balance			
Beginning Balance	($9,718,518)	($17,009,140)	($3,356,306)
Revenue(1)	$34,976,990	$38,088,745	$38,088,745
Total Expenses(2)	($42,267,612)	($43,382,895)	($45,462,605)
Less DR Incentives	$0	$13,753,335	$14,537,368
Less EE Incentives	$0	$5,193,650	$5,565,480
Net Expenses	($42,267,612)	($24,435,910)	($25,359,757)
Ending Balance	($17,009,140)	($3,356,306)	$9,372,682

(1) 2010 revenue; Jan-Aug actual $22,805,939, Sep-Dec forecast $12,171,051.
All forecast revenues based on June 1, 2010, Spring IPUC compliance filings per Order Nos. 31091, 31093, and 31097.
Rider revenues are 4.75% of forecast revenues.
(2) Total expenses for 2010 include Jan-Aug actuals, Sep-Dec forecast.
All expenses and incentive values based on current forecast.