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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR APPROVAL OF REVISIONS TO THE IRRIGATION PEAK REWARDS PROGRAM, SCHEDULE 23.	**CASE NO. IPC-E-10-46** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of Record, Weldon B. Stutzman, Deputy Attorney General, submits the following comments in response to Order No. 32158 issued on January 12, 2011.

BACKGROUND

On December 10, 2010, Idaho Power Company filed an Application requesting approval of changes to its Irrigation Peak Rewards Program (Schedule 23). The program is a voluntary load control program available to agricultural irrigation customers and is used to decrease the Company's system summer peak by interrupting service to specified irrigation pumps during June 15 through August 15. Under the program, the Company interrupts specified irrigation pumps any Monday through Saturday between the hours of 1:00 p.m. and 8:00 p.m. The Company uses either dispatchable or timer-based load control devices to interrupt selected pumps for a limited number of hours. In exchange for allowing the Company to interrupt electric service, participating customers receive a monthly monetary payment in the form of a bill credit for usage that occurs during June, July and August.

Based on a Company review conducted during 2010, Idaho Power is proposing to:

(1) Change the incentive payment structure for Dispatchable Options 1, 2, and 3 from a fixed incentive payment to a combination of a fixed and variable incentive payment;
(2) Pay the variable portion of the incentive by check after the end of the Program season;
(3) Modify the Dispatchable Option 3 requirements to fit the proposed payment structure;
(4) Change the opt-out penalty to $1.00 per kW for Dispatchable Options 1, 2, and 3;
(5) Extend the interruptible period from 8:00 p.m. to 9:00 p.m. on a voluntary basis;
(6) Implement one program test event per season that is not subject to a variable payment; and,
(7) Add language specifying that Program participation may be limited based on the Company's need for peak load reduction.

The Application states that the proposed program modifications reflect a collaborative process between Idaho Power and the Idaho Irrigation Pumpers Association, the Commission Staff, the Energy Efficiency Advisory Group, and the Integrated Resource Plan Advisory Council. The Company states that the program as revised would more closely align the program incentives with the Company's need for demand response.

STAFF ANALYSIS

The following comments discuss Staff's long-term objectives for demand response programs, and Idaho Power's proposal to align the design of the Irrigation Peak Rewards Program (Schedule No. 23) with the Company's varying need for demand response programs. Staff reviewed the Company's Application and corresponding testimony, and has serious concerns with the proposal.

Staff's Objectives for Demand Response

Demand Side Management (DSM) programs target overall conservation and efficiencies in energy usage, where demand response programs specifically target usage patterns during system peak. Demand response programs are dispatchable in a short period of time, are reliable as a firm load resource, and are inexpensive compared to the cost of an additional resource to meet peak loads. Staff believes cost-effective demand response is the best way to directly reduce peak demand and defer additional investment in peaking resources. Without prudently administered, cost-effective demand response during periods of system peak, utilities would have to rely on expensive market purchases or invest in additional system generation to meet peak load. According to the Company's testimony, "If not for the Program, growing summer peak loads would likely require the construction of additional simple cycle gas peaker capacity to meet system peak a few hours each year." Pengilly Direct, p. 4, l. 1-14. Staff believes that similar to a simple cycle gas peaker, the Irrigation Peak Rewards Program should be viewed as a reliable, long-term resource when planning future resources. This is consistent with the Company's approach to valuing the Program in past Integrated Resource Plans (IRP). Staff's objectives for the Program are that it be cost-effective, that annual participation remains stable, that the incentives avoid unnecessary complexity, and that the operational potential of the Program be fully utilized.

Company's Proposal

Every year Idaho Power evaluates the Irrigation Peak Rewards Program's cost-effectiveness, operational efficiency and customer satisfaction. However in 2010, the Company enhanced its annual review to assess the Program's design to insure it remains consistent with the need for demand response identified in the Company's Integrated Resource Plan. The proposed Program modifications are a direct result of that review. Pengilly Direct, p. 6, l. 14-15. Staff evaluated the Company's enhanced annual review and all of the Program modifications. These are discussed in varying detail below.

Change the Incentive Payment Structure

Staff analyzed the Company's proposal and supports changing the incentive structure from a fixed incentive payment to a combination of fixed and variable incentive payments. The split incentive captures the Program's operational similarities to a peaking supply side resource. However, Staff disagrees with the Company's proposal to base the fixed and variable incentive payments on the short term variations in needed demand response. The Company should consider designing the incentive payments with the objective of developing the Program into a long-term reliable resource, with consistency from year to year so participation levels do not drop.

Staff is concerned about the Company's proposal given the potential magnitude of the reduced incentive, the lack of justification for the new credit level, and the lack of research completed to support the Company's anticipated impact on customer participation. When compared to the current structure, the proposed change in incentive structure adversely impacts the economic decision to call an event.

Staff believes the Company has not demonstrated that it currently captures the economic value of the Program. If this proposal had been in place during the 2010 season, the Company would have only utilized the test event, whereas under the current structure it actually called three events. Idaho Power would have paid out $4.6 million in incentives instead of $11.5 million (Staff Production Request No. 8). The Company stated that it "anticipates that the proposed level of fixed incentive will be adequate to retain current participants." Pengilly Direct, p. 17, l. 5-7. As part of Production Request No. 6, Staff asked the Company to describe its studies, reviews, or market research used to support this conclusion. The Company was unable to provide any indication that the proposal will be adequate to retain current participants. Idaho Power should proactively conduct studies to determine how changes might impact the Program, so there is a better understanding of how Program participation will change. The Company should also consider setting the incentive level during the first year at a level that minimizes the risk of losing participants. This would give the Company an opportunity to gradually evaluate the impact of Program changes on participation levels.

In addition to the stated concern over future participation, Staff disagrees with the Company's approach for determining the fixed incentive because it fails to value the Program as a long-term resource. The Company's proposal was developed by comparing its forecasted load duration curves to its existing and committed resource capacity during the highest 60 hours. The results of the comparison showed a variation in needed annual capacity of 50% over the next five years, primarily due to the addition of Langley Gulch Power Plant. In order to align the Program with the forecasted variation in needed demand response, the Company allocated 40% of the total incentive for participation, and 60% based on Program utilization. A participant will receive 40% of the current incentive if the Company has no demand response events, and will receive 106% of the current incentive if the Company fully utilized the Program's 60 hours. According to the Company's response to Staff's Production Request No. 5, the Company plans on making future decisions about the incentive structure after doing a demand response needs assessment from upcoming IRPs. This short-term approach introduces volatility in credit valuation and Program participation as the Company looks to make modifications biannually, when each IRP is filed. Staff believes the Company should continue to use an avoided peaking resource methodology to determine fixed incentives over the long-term, as it has in the determination of cost effectiveness. The long-term investment in demand response is analogous to the operational characteristics and investment in a simple cycle combustion turbine. The proportion of fixed costs necessary to build and operate a simple cycle peaking plant would be a more appropriate guideline for determining the proportion of fixed Program incentives.

Payment of the Variable Incentive

If variable incentive payments are established, Staff believes it is reasonable to pay at the end of the season, but the Company may want to consider paying the variable portion as quickly as possible following the end of the Program season. The Company currently pays a fixed incentive amount regardless of how often the Program is used during the billing period or season. With the Company's proposal to go from a fixed incentive payment to a combination of a fixed and variable incentive payment, the Company proposes paying the variable portion no more than 60 days after the August 15th end date of the Program. It states that this will "avoid issues with its billing system" and "highlight to the participants that they are paid the fixed incentive through the bill credit and that the variable portion of the payment is based on the amount of time the Program operates." Pengilly Direct, p. 23 & 24, l. 20-23 & l. 1-2. Staff does not support the Company's proposed levels of fixed and variable incentive payments.

Dispatchable Option 3 Modifications

The Company is proposing three modifications to Dispatchable Option 3. The modifications support its proposed incentive payment structure, and make the Program a more reliable resource. Specifically, the Company's proposal:

(1) Requires participants to nominate their load reduction;

(2) Changes the opt-out policy; and

(3) Changes the baseline from which participants' load reduction is calculated.

Assuming a fixed and variable incentive structure was appropriately established, Staff would support the Company's proposal requiring participants to nominate their load reduction. This makes calculating the fixed portion of the proposed incentive structure possible, and allows the Company to better plan its capacity during interruptions. Dispatchable Option 3 participants currently have the option to provide varying portions of curtailment during each particular event, so determining the appropriate fixed incentive payment under the Company's proposed incentive structure is impossible. The Company has proposed that participants nominate demand prior to June 1st of each year so it can determine the fixed incentive to pay participants. The Company has also proposed that participants nominate demand because the current method of calculating the Demand Credit absent any events, could result in a larger amount than if an event actually occurred. When there are no events during a billing period, the current Demand Credit is calculated based on maximum demand during the billing period, whereas when an event is called, it is calculated based on maximum demand 24 hours prior to an event. When maximum demand during a billing period is used to determine the Demand Credit instead of the period immediately preceding an event, the Demand Credit potentially pays for more capacity than the Company would receive during an event. Staff believes the Company's proposal to use participants' nominated load reduction in the absence of an event would more accurately reflect their contribution to the Program during an event. Similar to Dispatchable Options 1 and 2, it is reasonable to have participants nominate demand prior to the Program season.

Staff also believes it is reasonable for participants to pay an opt-out penalty under an appropriately established fixed and variable incentive structure. Given the proposed incentive structure without an opt-out penalty, participants would receive a fixed payment for capacity they may not provide. Idaho Power proposes changing the opt-out policy to support the proposed incentive structure. Dispatchable Option 3 currently does not have an opt-out penalty because participants provide varying curtailment amounts during each particular event. The proposal applies an opt-out penalty to the difference between what was provided and what was nominated. Absent an opt-out penalty, a participant may not completely curtail what is nominated during an event, but would still receive the fixed incentive based on the nomination.

Staff recommends the Commission deny the Company's proposal to calculate the baseline using the 12-hour night time period (10:00 p.m. and 11:00 a.m.) prior to an event. The Company's rationale behind the proposal is to limit gaming by participants in order to receive a larger credit. However, since the Company provides participating customers notice of a pending load control event by 4:00 p.m. MDT on the day prior to each event, the Company's proposal would inaccurately capture normal usage. If customers increase their overnight usage in anticipation of being curtailed the following day, the load reduction estimate might be too high. However, if participants begin to shut down early in anticipation of being curtailed, the load reduction estimate might be too low. Staff agrees with the Company that the current way of calculating participants' load reduction could overestimate normal usage because it is based on a single spike in usage, but Staff disagrees that the proposal would result in a more accurate estimate than the current method.

Participants' load reduction is currently calculated by subtracting the average demand during an event from the baseline, defined as maximum demand 24 hours prior to an event. The current and proposed baseline is calculated using the period prior to an "event" and not prior to the "event notification." Staff believes this may exacerbate the problem of participants spiking usage following the "event notification" to receive a larger payment. In a future proposal, the Company may want to consider using the day prior to the event notification, by averaging participants' usages over the same period in which the actual event occurred. If two consecutive event days were called, baseline could be calculated using the day prior to the first event notification, by averaging usage over the full time period both events occurred.

Opt-out Penalty

After Staff analyzed the Company's proposal to change the opt-out penalty for Dispatchable Options 1 and 2, Staff believes that it is reasonable given the objective of the Program. As mentioned above, under an appropriately established fixed and variable incentive structure, Staff believes it is reasonable for Option 3 participants to have an opt-out penalty similar to Dispatchable Options 1 and 2. The proposed penalty will also "make it easier for customers to estimate what an opt-out is going to cost ahead of time, which could influence their decision to opt-out." Pengilly Direct, p. 19, l. 12-15. Staff compared the current $0.005 per kWh opt-out penalty to the proposed $1.00 per kW opt-out penalty given a number of scenarios, and found the proposed opt-out penalty is lower and easier to calculate. If Idaho Power called the maximum number of hours during the Program Season and a participant did not provide the entire nominated kW during five events (the total allowed per billing period), the penalty would never exceed 100 percent of the credit.

Extending the Interruptible Period

Staff supports the Company's proposal to extend the interruptible period from 8:00 p.m. to 9:00 p.m., however Staff proposes extending the interruptible period on a mandatory basis. According to Staff's analysis of the Company's load duration study, to fully utilize the operational impact of the Program, it is necessary for the Company to extend the interruptions beyond 8:00 p.m. As explained in testimony, ideally a "flat load shape during the demand response program operational period would indicate that 100 percent of the demand reduction provided by the programs is avoiding the need for capacity rather than something less than 100 percent that would exist under the 'trough effect'." Pengilly Direct, p. 7, l. 16-24.

The Company proposes paying the "Extended Interruption" customers $0.05 per kWh more than the "Standard Interruption" during every interruption. The Company's additional incentive for the "Extended Interruption" was determined based on its theoretical 2011 dispatch during the extended hour, and the estimated incentive necessary to encourage participation. Staff asked the Company to provide supporting executable workpapers illustrating how it arrived at the "Extended Interruption" amount, but it was unable to provide any information. Even though the Company's theoretical 2011 dispatch during the extended hour is low, Staff believes that absent any underlying data to estimate participation, the Company's proposal is merely a starting point to evaluate participation.

If Staff's proposal to extend the interruptible period on a mandatory basis is adopted, the Company should closely monitor participation. If the level of participation drops, and paying more for an additional hour of interruption is cost-effective, the Company should consider increasing the incentive. Staff believes to fully achieve the operational impact of the Program, it is necessary for the Company to require that participants extend the interruptions to 9:00 p.m.

One Program Test Event

Staff supports the Company's proposal to include one Program test event per season. The Company currently tests its dispatchable control device communication prior to each season, but does not implement a full pre-season interruption to test every aspect of the Program. Staff believes it is important for the Company to test the reliability and timeliness of interruptions. This provides assurance that the capacity will be available when needed. In this proposal, the Company includes one Program test event per season that is not subject to a variable payment. If variable incentive payments are established, Staff also believes it is reasonable that the test event not be subject to a variable payment. Testing the Irrigation Peak Rewards Program is different than testing supply side resources where the Company may be able to capitalize on economic benefits. Testing the Irrigation Peak Rewards Program must happen prior to the start of the season when market prices for energy are typically low, and the Company is less likely to capture economic benefits.

Limiting Program Participation

Staff recommends the Commission deny the Company's proposal to add language to the "Availability" section of the proposed tariff limiting Program participation based on its need for peak load reduction. Every year Idaho Power models the Program's cost effectiveness over a 20-year period by looking at future financial and Demand-Side Management alternative costs. As reported in the Demand-Side Management 2009 Annual Report, the current Programs benefit cost (B/C) ratio was 1.50 over a 20 year planning period. Even with the Company's proposed changes, the Company tested numerous Program scenarios where the B/C ratios were greater than one. As long as the Irrigation Peak Rewards Program has a B/C ratio greater than one, it is not clear why participation should be limited, particularly since it will cost effectively help delay future plant investment. Demand response is intended to avoid the next power plant. If the Company has a short-term view of demand response and decides to limit the Program's growth because of short term variations in its need for peak load reduction, rate payers will be left paying for more expensive generation earlier than they otherwise would. The Company should not only accept, but promote participants in the Program in order to achieve peak load reduction over the long term.

STAFF RECOMMENDATION

Staff believes that most of the Company's proposed Program changes may have merit, but since Staff disagrees with the Company's proposed fixed and variable incentive levels that propagated the changes, Staff can only support and recommend Program changes in the following areas:

(1) Changing the opt-out penalty to $1.00 per kW for Dispatchable Options 1 and 2;

(2) Extending the interruptible period to 9:00 p.m. on a mandatory basis; and,

(3) Implementing one program test event per season.

Respectfully submitted this day of February 2011.

for Kristine A. Sasser
Weldon B. Stutzman
Deputy Attorney General

Technical Staff: Matt Elam

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 9th DAY OF FEBRUARY 2011, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-10-46, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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