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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR APPROVAL OF NEW TARIFF SCHEDULE 82, A COMMERCIAL AND INDUSTRIAL DEMAND RESPONSE PROGRAM (FLEX PEAK PROGRAM).	)	CASE NO. IPC-E-15-03

IDAHO POWER COMPANY

DIRECT TESTIMONY OF

TAMI WHITE

Q. Please state your name and business address.

A. My name is Tami White and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

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

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Senior Manager of Rate Design in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I earned a Bachelor of Business Administration degree in Accounting from California State University, Stanislaus. I have attended various electric utility courses, including "Electric Utility System Operation," a course offered through Professional Training Systems, Inc., and "Overview of System Operations" presented by the Western Electricity Coordinating Council. In 2014, I attended the Utility Executive Course at the University of Idaho.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1999 as a Financial Analyst in the Company's Delivery Finance Support area where I provided accounting and financial support services to the Delivery Business Unit. In 2005, I was promoted to Finance Team Leader where I was responsible for leading a group of Financial Analysts, Accountants, and

Accounting Specialists in providing accounting and financial support services to the Operations Business Unit. I was responsible for all aspects of the monthly accounting closing process for the Operations Business Unit and for the monthly billing and settlements processes for transmission sales and purchases, wholesale energy transactions, Public Utility Regulatory Policies Act of 1978 (PURPA) transactions, large special contracts, and joint use transactions. While working in Operations Finance Support, I was involved in the development of the Company's Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT") formula rate for transmission services.

In October of 2010, after 11 years in finance, I accepted a position as Manager of FERC and Regional Affairs in the Regulatory Affairs Department. In this position, I was responsible for managing regulatory activities such as the preparation and filing of Idaho Power's OATT rates for transmission service, supervising participation and settlement negotiations in Bonneville Power Administration rate cases, and creating analyses that form the basis for Idaho Power's FERC regulatory strategy.

In January of 2012, I was promoted to Senior Manager of Rate Design. As Senior Manager of Rate Design, I oversee the Company's rate design activities such as regulatory ratemaking and compliance filings, tariff administration, and the development of various pricing strategies and policies.

Q. What is the Company requesting in this proceeding?

A. Idaho Power is requesting that the Idaho Public Utilities Commission ("Commission") approve a new tariff schedule that provides for the implementation of an optional internally managed demand response program for the commercial and industrial ("C&I") customer classes[1], and authorize the Company to continue recovering the C&I demand response program expenses in the manner it currently does.

A similar program has historically been managed by a third party, and has been referred to as the FlexPeak Management program; however, for the remainder of my testimony I will refer to the historical program as the "third-party program." The Company's internally-managed program will be referred to as the Flex Peak Program ("Program").

Q. How is the Company's case organized?

A. Idaho Power is filing an application for a Commission order authorizing the Company to implement an optional Schedule 82, Flex Peak Program, and to continue to

[1] The proposed program will be available to C&I customers taking service under Schedules 9, 19 or a Special Contract.

recover expenses associated with the Flex Peak Program in a manner consistent with the current recovery approach. In support of this application, the Company is filing my testimony and the testimony of Mr. Quentin Nesbitt who is the Energy Efficiency Program Leader responsible for overseeing Idaho Power's C&I and irrigation demand-side management ("DSM") programs.

My testimony along with the testimony of Mr. Nesbitt, will inform the Commission as to why it is appropriate and in the best interest of customers for Idaho Power to transition from a third-party operated demand response program to the Company-operated Flex Peak Program.

Q. Please provide a summary of your testimony.

A. My testimony is organized into three sections. The first section will provide the history of the third-party program. The second section will describe stakeholder input received to date. Finally, in the third section I will discuss program cost-effectiveness and how the Company plans to recover program expenses.

I. HISTORY OF THE C&I DEMAND RESPONSE PROGRAM

Q. What is the Flex Peak Program?

A. The Flex Peak Program is a voluntary demand response program for the Company's C&I customers who are willing and able to reduce their electrical energy loads for short periods of time from mid-June through mid-August when electrical loads on Idaho Power's system are high.

Q. When was the third-party program initially offered to Idaho Power's C&I customers?

A. The Company filed an application on March 2, 2009, seeking Commission approval of an agreement ("third-party Agreement") with a contractor, EnerNOC, Inc. ("EnerNOC"), to implement and manage the third-party program beginning in the summer of 2009. The Commission approved the third-party Agreement in Order No. 30805, issued on May 15, 2009. EnerNOC solicited participants and the third-party program was available for the 2009 summer season.

Q. How did Idaho Power select EnerNOC to manage the third-party program?

A. EnerNOC was selected by Idaho Power through a competitive request for proposal ("RFP") process to implement and manage the program. Through that process, EnerNOC demonstrated it had successfully implemented similar programs for other utilities throughout the country.

Q. What were EnerNOC's responsibilities under the third-party Agreement?

A. Once notified by Idaho Power of a demand response event, EnerNOC was responsible for supplying a committed load reduction to Idaho Power's system. Further, EnerNOC was responsible for developing and implementing all marketing plans, securing all participants, installing and maintaining all equipment beyond Idaho Power's meter necessary to reduce demand, tracking participation, and reporting results to Idaho Power.

Q. Please explain the Company's 2009 request for Commission approval of the third-party Agreement.

A. The third-party Agreement included a five-year term with demand reduction targets to be achieved during each of those five years. The initial targets for years 2009 through 2013 ranged from two megawatts ("MW") of demand reduction during the 2009 program year up to 50 MW of demand reduction during the 2013 program year.

Q. Did the Company request Commission approval for any modifications to the third-party Agreement?

A. Yes. On February 26, 2010, the Company requested approval for an amendment to the third-party Agreement which primarily sought to: (1) clarify conditions under which Idaho Power would be charged "energy payments" during demand reduction events, (2) adjust the calculation of the "Day-of-Load Adjustment," (3) decrease the penalty EnerNOC would incur for failing to commit to a demand reduction, and (4) add a non-solicitation clause. This first amendment was approved by the Commission in Order No.

31098, issued on June 2, 2010. The Company later filed two other amendments as described below.

Q. Did Idaho Power request suspension of its Company-managed demand response programs in 2012?

A. Yes. In December of 2012, in response to the lack of near-term peak-hour deficits identified in the Load and Resource Balance analysis prepared for the 2013 Integrated Resource Plan ("IRP"), Idaho Power filed a request (Docket No. IPC-E-12-29) with the Commission for authority to temporarily suspend two of its three demand response programs (A/C Cool Credit and Irrigation Peak Rewards). The Commission authorized the suspension of the A/C Cool Credit and Irrigation Peak Rewards demand response programs in Order No. 32776, issued on April 2, 2013.

Q. Was the third-party program or the third-party Agreement impacted by the suspension of Company-managed demand response programs?

A. Yes. On March 7, 2013, following the Company's request to suspend its other two demand response programs in Case No. IPC-E-12-29 described above, the Company filed a petition requesting the Commission approve a second amendment to the third-party Agreement. The second amendment reduced the weekly MW of nominated demand reduction obligations to a range of 20 MW to 35 MW to ensure that the then-current participation levels were sustainable while limiting future program costs associated with higher demand reduction levels that the Company's IRP indicated it did not need at the time. This second amendment was approved by the Commission in Order No. 32805, issued on May 9, 2013.

Q. Was the third-party Agreement impacted by the Company's Demand Response Programs Settlement Agreement ("Settlement Agreement") entered into and approved by the Commission in Case No. IPC-E-13-14?

A. Yes. On March 7, 2014, subsequent to the Commission's approval of the Settlement Agreement, the Company filed a petition seeking approval of a third amendment to the third-party Agreement. This amendment modified the third-party Agreement to comply with terms of the Settlement Agreement and sought to extend the contract termination date through December 2014. This third amendment was approved by the Commission in Order No. 33036, issued on May 7, 2014. The Settlement Agreement is attached as Exhibit No. 1 to my testimony.

Q. Did the Settlement Agreement specifically address the C&I demand response program?

A. Yes. Signing parties to the Settlement Agreement reached agreement on the design of each of the Company's demand response programs, specifically addressing the C&I demand response program in Section 9 of the

Settlement Agreement which describes parameters surrounding participation, program design, and the incentive structure.

Q. What are the parameters surrounding participation and program design?

A. The signing parties agreed in Section 9.a. that the Company would not actively seek to expand the capacity of the C&I demand response program.

The signing parties also agreed in Section 9.b. that the program will be available from June 15 through August 15, Monday through Friday, from 2:00 p.m. - 8:00 p.m., excluding holidays. Each dispatch event will last up to four hours per participant within the available program hours. Dispatch events will not occur more than 60 hours per season. Idaho Power will conduct a minimum of three dispatch events per season. There will be two hours advance notice to participants. In the event of a system emergency, participants may be called to voluntarily reduce their load.

Q. What parameters did the signing parties agree to regarding the incentive structure?

A. The signing parties agreed in Section 9.c. that a fixed and variable incentive structure may be appropriate, as long as the variable portion is low enough that it does not prevent the program from being dispatched. If a fixed and variable incentive structure is used, a minimum of three dispatch events will be included in the fixed incentive. The variable incentive will be paid to participants if Idaho Power conducts dispatch events during the program season for more than the three minimum dispatch events.

Q. Does the Settlement Agreement contain any other requirements with which Idaho Power must comply with when offering its demand response programs?

A. Yes. The Settlement Agreement discusses six overarching concepts that are to guide Idaho Power in the implementation of its demand response programs. These high-level concepts are listed in Section 4.a of the Settlement Agreement and include the concept that Idaho Power will provide demand response program offerings for all three customer classes (residential, commercial/industrial, and irrigation). The signing parties also agreed on the annual value of Idaho Power's demand response portfolio as set forth in Section 6 of the Settlement Agreement.

Q. Does the Settlement Agreement identify a term during which Idaho Power has agreed to offer its demand response programs?

A. Yes. Section 3 discusses the term, stating in part:

> [T]he Settlement Agreement shall be in effect beginning on the date it is approved

> by the Commission and shall apply to the Company's demand response programs for 2014 and beyond until a change occurs in the Company's system operations or cost-effectiveness of a demand response program that would warrant reevaluation of the Settlement Agreement's term.

Q. Was demand response included in the 2013 IRP?

A. Yes. The preferred portfolio of the 2013 IRP accepted for filing by the Commission in Order No. 32980 assumes a demand response capacity of 50 MW is available beginning in 2024 and steps up to approximately 370 MW by 2032.

Q. Will demand response be included in the 2015 IRP to be filed with the Commission in June 2015?

A. Yes. Idaho Power considers demand response a committed resource and 390 MW[2] (including the C&I program) of demand response will be included in each portfolio that is analyzed as part of the 2015 IRP process.

Q. Did the Company consider continuing with third-party management of the C&I demand response program beyond the December 2014 expiration date of the third-party Agreement?

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[2] Based on the Settlement Agreement and the 2014 actual enrollment of demand response, the Company included a committed resource of 390 MWs of demand response in the 2015 IRP. The Commission acknowledged the Company's anticipated level of demand response of 403 MWs for the 2014 summer season in Order No. 33084, issued on July 30, 2014.

A. Yes. In anticipation of the third-party Agreement expiring in December 2014, the Company issued an RFP during the summer of 2014 seeking assistance operating a C&I demand response program by a third party beyond 2014.

Q. How were the responses evaluated?

A. Idaho Power compared the proposals received to a Company-operated program that served as a benchmark.

Q. Was there a successful bidder?

A. No.

Q. What prevented Idaho Power from pursuing a contract with either bidder?

A. The primary concern that prevented Idaho Power from pursuing either bid was the Company's conclusion that cost savings for customers could be achieved by the Company managing the program itself rather than through a third party.

II. STAKEHOLDER INPUT

Q. Did the Company solicit input from the Energy Efficiency Advisory Group ("EEAG") to discuss the Company's conclusions regarding the third-party bids and the alternate proposal to operate an internally-managed C&I demand response program?

A. Yes. The Company held a webinar with its EEAG membership on Friday, January 9, 2015, to solicit EEAG's preference and support for either renewing the contract with EnerNOC or having the Company administer the program.

Q. Did you participate in this webinar?

A. Yes.

Q. Did the EEAG offer a recommendation?

A. Yes. My impression is that the majority of EEAG members are cautiously supportive of an Idaho Power-managed program. One EEAG member expressed a neutral position and one EEAG member recommended the Company retain EnerNOC as the third-party manager of the program.

Q. Why do you think the EEAG was cautious about its support for Idaho Power managing the program?

A. EEAG members expressed concerns regarding how the Company would handle less certain nomination levels, concerns about how the Company would ensure that it does not pay for load reduction that is not achieved, and concerns about the aggressive timeline required to have a program designed, approved, and operating prior to the June 15th start of the demand response program season, among others.

Q. Can the Company address the concerns expressed by EEAG members?

A. Yes. Mr. Nesbitt, who will oversee the Company-managed Flex Peak Program will address the concerns I identified in his testimony.

III. PROGRAM COST-EFFECTIVENESS AND COST RECOVERY

Q. Will the Flex Peak Program be cost-effective?

A. Yes, I believe the Program will be cost-effective because it has historically been cost-effective, and Idaho Power will be able to operate the Program at a lower cost per MW of load reduction.

Q. How will the cost-effectiveness of the Flex Peak Program be measured and reported?

A. According to the previously described Settlement Agreement, the annual value of Idaho Power's demand response portfolio is equal to the levelized annual cost of the minimum size deferred resource, which was calculated to be approximately $16.7 million. In 2014, the cost of operating the Company's entire demand response portfolio was $10.6 million, well under the $16.7 million dollar threshold. If all three programs were dispatched for the maximum allowable number of hours, the total costs would have been approximately $13.8 million.

Q. Did the Company compare the costs of managing the Program internally versus the historical costs of the third-party managed program?

A. Yes. The Company looked at the average historical total program costs over the course of the 6 years the third-party program has been in place. The total program costs averaged approximately $2.0 million annually for nominated reductions at generation-level ranging between 8.5 MWs and 39.3 MWs annually.

Based on the Company's proposed Program design, the Company anticipates total Program costs to range from approximately $1.1 million annually with no variable payments up to approximately $1.4 million if the Program has 35 MW of nominated reductions and was dispatched for the maximum number of hours allowed, which is 60.

Q. Is the Company proposing a change to customer rates associated with the ongoing funding of the Program?

A. No, not at this time. The Company believes that the current level and method of recovery will adequately fund the ongoing operation of the Program for the foreseeable future.

Q. Please explain how Idaho Power currently recovers the third-party program costs.

A. On December 30, 2011, the Commission issued Order No. 32426 approving $11.3 million of normal or "base level" demand response incentive payment costs to become part of base rates effective January 1, 2012. Of that base level amount, approximately $2.0 million was associated with the C&I demand response program costs. The demand response cost recovery method approved by Order No. 32426 authorized the Company to move demand response incentive payment costs into base rates and track them as part of the annual Power Cost Adjustment ("PCA") mechanism.

Annually, as part of the PCA, the forecasted level of demand response incentive payments would be compared to the normal level included in base rates to determine the level of demand response incentive payment cost recovery or credit to be included in the PCA forecast. One hundred percent of any deviations between actual demand response incentive payment costs and forecasted costs would be included in the following year's PCA true-up. It should also be noted that the demand response costs recovered in base rates and tracked through the PCA would include only the incentives paid to customers for demand reduction or the total amounts paid to third-party demand-aggregator contractors for demand reduction; Idaho Power labor and expenses associated with administration of the demand response programs would continue to be recovered through the Energy Efficiency Rider.

Q. How will the current regulatory treatment of demand response cost recovery apply to the Flex Peak Program?

A. Under the current regulatory treatment of demand response cost recovery, Idaho Power would recover Program incentive payment costs through base rates with deviations from the base level tracked through the PCA mechanism. The Company would continue to recover Program labor and other administrative expenses through the Energy Efficiency Rider.

The current level of C&I demand response program costs recovered through base rates is the same level approved by Order No. 32426, approximately $2.0 million a year. If approved, the Company anticipates incentive payment costs from an Idaho Power-managed program to range from approximately $0.9 million annually with no variable payments up to approximately $1.27 million if the program has 35 MWs of nominated reductions and is dispatched for the maximum number of hours allowed.

Continuing the use of the PCA mechanism to track deviations between actual Program incentive payment costs and those recovered in base rates will allow 100 percent of any annual Program cost savings to flow to customers by June of the following year.

Idaho Power will report in its DSM Annual Report on all activities associated with the Flex Peak Program including how it impacts the Energy Efficiency Rider, as well as detailing the incentives to be included in the PCA calculation.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
)   ss.
County of Ada   )

I, Tami White, having been duly sworn to testify truthfully, and based upon my personal knowledge, state the following:

I am employed by Idaho Power Company as a Senior Manager in the Regulatory Affairs Department and am competent to be a witness in this proceeding.

I declare under penalty of perjury of the laws of the state of Idaho that the foregoing pre-filed testimony and exhibit are true and correct to the best of my information and belief.

DATED this 4th day of February 2015.

Tami White
Tami White

SUBSCRIBED AND SWORN to before me this 4th day of February 2015.

Kimberly K. Towell
Notary Public for Idaho
Residing at: Star, Idaho
My commission expires: 12-20-2020

KIMBERLY K. TOWELL
NOTARY
PUBLIC
STATE OF IDAHO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-15-03

IDAHO POWER COMPANY

WHITE, DI
TESTIMONY

EXHIBIT NO. 1

DEMAND RESPONSE PROGRAMS
SETTLEMENT AGREEMENT

This settlement agreement ("Settlement Agreement" or "Agreement") is entered into by and among the following participants to the demand response workshops: Idaho Power Company ("Idaho Power" or "Company"), the Staff of the Idaho Public Utilities Commission ("Staff"), the Idaho Irrigation Pumpers Association, Inc. ("IIPA"), the Idaho Conservation League ("ICL"), the Snake River Alliance ("SRA"), EnerNOC, Inc. ("EnerNOC"), and Mike Seaman. These entities and individuals are collectively referred to as the "Parties," and individually as a "Party," to the Agreement.

WHEREAS, when, in late 2012, the Load and Resource Balance Analysis performed during the development of Idaho Power's 2013 Integrated Resource Plan showed no peak-hour capacity deficit until 2016, Idaho Power filed for changes to its A/C Cool Credit program, Irrigation Peak Rewards program, and FlexPeak Management program (collectively "DR Programs") in Docket Nos. IPC-E-12-29 and IPC-E-13-04;

WHEREAS, following the temporary suspension of the A/C Cool Credit program and Irrigation Peak Rewards program in 2013 and contract changes for the FlexPeak Management program, the Parties attended a series of five workshops ("DR Workshops") for all interested parties and stakeholders to discuss how the Company includes demand response ("DR") in its Integrated Resource Plan ("IRP"), how it calculates cost-effectiveness of DR, the purpose of DR, Idaho Power's DR Programs and design, and settlement options for Idaho Power's DR Programs in 2014 and beyond;

WHEREAS, these DR Workshops occurred in Case No. IPC-E-13-14, were noticed in Docket UM 1653, and were attended by parties to both dockets, as well as members of the public and other stakeholders;

WHEREAS, UM 1653 followed the workshop process in Case No. IPC-E-13-14 in an effort to allow all interested Idaho and Oregon parties and stakeholders to collectively provide input and agree upon Idaho Power's DR Program details; and

WHEREAS, throughout the course of the DR Workshops, the Parties reached agreement on certain aspects of Idaho Power's DR Programs.

NOW THEREFORE, in consideration of the mutual promises set forth herein, the sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. **Recitals.** The above-stated recitals are incorporated and made a part of this agreement to the same extent as if the recitals were set forth in full at this point.

2. **Public Interest.** This Agreement is a fair, just, and reasonable compromise of contested issues and its acceptance by the Idaho Public Utilities Commission ("IPUC" or "Commission") would be in the public interest. The Agreement and its acceptance by the Commission will reasonably resolve the issues related to Idaho Power's DR Programs. Therefore, the Parties recommend that the Commission approve the Agreement and all of its terms and conditions without material change or condition pursuant to IPUC RP 274.

3. **Term.** This Agreement shall be in effect beginning on the date it is approved by the Commission and shall apply to Idaho Power's DR Programs for 2014 and beyond until a change occurs in Idaho Power's system operations or cost-effectiveness of a DR Program that would warrant reevaluation of the Agreement's terms. In such event, Idaho Power will consult

its Energy Efficiency Advisory Group ("EEAG") and then make an appropriate filing at the Commission. Similarly, a party to this Agreement, may petition the Commission to open a docket to reevaluate the terms of this Agreement if Idaho Power experiences a change in system operations or the cost-effectiveness of a DR Program so warrants.

4. **<u>Concepts</u>.** The Parties and workshop participants agreed that the following overarching demand response concepts should guide Idaho Power's implementation of its DR Programs:

a. The Company must:

i. Use existing demand response resources when possible. This includes using, to the extent possible, current demand response equipment owned or available to Idaho Power and participating demand response customers, which currently represents approximately 400 megawatts ("MW") of potential demand response capacity.

ii. Include demand response offerings for all three customer classes (residential, commercial/industrial, and irrigation).

iii. Keep costs as low as possible.

iv. Reevaluate the value calculation as the IRP changes.

v. Take a long-term outlook. In order to have viable demand response programs in the long term, the programs must continue in the short term.

vi. Calculate the avoided cost used for demand response by using the avoided capacity cost of a 170 MW single cycle combustion turbine ("SCCT") multiplied by the effective load carrying capacity ("ELCC"), measured over 20 years, plus the corresponding deferred energy savings for 60 program hours.

vii. Strive for consistency in dispatch requirements across DR Programs.

b. Uses for demand response beyond reducing peak loads may be: load following, non-spinning operating reserves, improved reliability during emergency situations, and flexibility to address delays in building new supply-side peaking resources. The workshop participants broke into small groups and discussed the possibilities of load following and reserves. Based upon these workgroup findings, Idaho Power will investigate the feasibility of using demand response as operating reserves and make a determination on feasibility by the end of the 3rd quarter of 2014. If Idaho Power determines that a pilot is feasible, it will create a proposal and work with Staff and other interested stakeholders to develop a pilot program.

c. This Agreement applies only to Idaho Power's Demand Response Programs, and the concepts are not applicable to any of the Company's other DSM Programs.

5. **Resource Size.** The minimum size of the deferred resource used for the value calculation is 170 MW. It is appropriate for Idaho Power to incur and recover costs based on deferring this resource.

6. **Value.** The annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, measured over a period of 20 years, plus the corresponding deferred energy savings for 60 program hours. As of the date of this Agreement, the calculation leads to an annual value of $16.7 million dollars for the entire DR Program portfolio. The demand response value calculation shall include this value even in years when the IRP shows no peak-hour capacity deficit. The annual value calculation will be updated with

each IRP based on changes that include, but are not limited to need, capital cost, or financial assumptions.

7. **A/C Cool Credit Program**. Idaho Power will implement the A/C Cool Credit program in a manner consistent with the tariff Schedule 81. A true and correct copy of the tariff is attached to this Agreement as Attachment 1 and is incorporated herein as if set forth in full at this point.

a. Participants. Participants are residential customers who are presently enrolled in the program and have a load control device installed. All paging devices installed at current participants' residences will be replaced with AMI-compatible devices, with the goal of completing replacement in time for the 2014 program season. Idaho Power will not actively promote the A/C Cool Credit program to solicit new participants through marketing tactics, but will accept new participants in this program who request to participate, regardless of whether they were previously participants in the program. In order to use existing equipment, Idaho Power will contact and attempt to recruit customers who move into a home that already has a load control device installed. If a customer enrolls in the A/C Cool Credit program at a residence that has a paging device, the load control device will be replaced with an AMI-compatible device. Idaho Power will also attempt to recruit participants who change residences to a location that does not have a load control device. An A/C Cool Credit program load control device will remain in place unless a customer requests the load control device be removed.

b. Program Details. The A/C Cool Credit program will be available from June 15 through August 15, Monday through Friday, excluding holidays. Each dispatch event will last no longer than four hours for each participant. Dispatch events will not occur more than 15 hours per week or 60 hours per season. In the event of a system emergency, demand response capacity from the A/C Cool Credit program will be available for immediate dispatch. Idaho Power will conduct a minimum of three dispatch events per season. No advanced notice to participants is required prior to executing each dispatch event. Participants, with advance notice, may opt out of two events per season.

c. Incentive. Participants will receive a fixed incentive of $15 for the season, which will be issued as a credit on one or more of the participant's monthly bills for the program months.

d. Program Size. If participation in the A/C Cool Credit Program changes, Parties to this Agreement may file an application to modify the program as set forth in Section 3.

8. **Irrigation Peak Rewards Program.** Idaho Power will implement the Irrigation Peak Rewards program in a manner consistent with the tariff Schedule 23. A true and correct copy of the tariff is attached to this Agreement as Attachment 2 and is incorporated herein as if set forth in full at this point.

a. Participants. Participation is limited to past Irrigation Peak Rewards service locations where an active, working load control device exists as described in more detail in Attachment 2. The Company will not actively market the Irrigation Peak Rewards program as described in more detail in Attachment 2.

b. Program Details. The Irrigation Peak Rewards program will be available from June 15 through August 15, Monday through Saturday, from 1:00 p.m.-9:00 p.m., excluding holidays. Each dispatch event will last no longer than four hours for each participant. Dispatch events will not occur more than fifteen (15) hours per week or sixty (60) hours per season. In the event of a system emergency, demand response capacity from the Irrigation Peak Rewards program will be available for immediate dispatch. Idaho Power will conduct a minimum of three dispatch events per season. Participants with Interruption Option 3 will be given at least four hours advanced notification. There will be no notification required for participants with Interruption Options 1 and 2. Participants may opt out of an event. An opt-out fee of $5.00 per kilowatt ("kW") per event will apply for the first three events and $1.00 per kW per event for subsequent events. The opt-out fee will not exceed the total bill credit for the program season.

c. Incentive. Participants will receive a fixed incentive in the form of a demand and energy component which is approximately $16 per kW per season, as set forth in more detail in Attachment 2. The fixed incentive shall include the above-mentioned three minimum dispatch events. If Idaho Power conducts dispatch events in the Irrigation Peak Rewards program in addition to the three minimum dispatch events, Participants will receive a variable incentive of $0.148 (or $0.198 for the 9:00 p.m. option) per kWh as set forth in more detail in Attachment 2, which, with the realization rate included, results in a cost to Idaho Power of approximately $0.22 per kWh.

9. FlexPeak Management Program. Idaho Power will implement the Flex Peak Management program using the following design parameters.

a. Participants. Idaho Power will not actively seek to expand the capacity of the FlexPeak Program. Participants are industrial and large commercial customers.

b. Program Details. The FlexPeak Management program will be available from June 15 through August 15, Monday through Friday, from 2:00 p.m.-8:00 p.m., excluding holidays. Each dispatch event will last up to four hours per participant within the available program hours. Dispatch events will not occur more than 60 hours per season. In the event of a system emergency, demand response capacity from the FlexPeak Management program will be available. Idaho Power will conduct a minimum of three dispatch events per season. There will be two hours advanced notice to participants.

c. Incentive. A fixed and variable incentive structure may be appropriate, as long as the variable portion is low enough that it does not prevent the program from being dispatched. If a variable and fixed incentive structure is used, a minimum of three dispatch events will be included in the fixed incentive. The variable incentive will be paid to participants if Idaho Power conducts dispatch events in the FlexPeak Management program for more than the three minimum dispatch events.

10. **Confidentiality.** As provided in RP 272, other than any testimony filed in support of the approval of this Agreement, and except to the extent necessary for a Party to explain before the IPUC its own statements and positions with respect to the Agreement, all statements made and positions taken in negotiations relating to this Agreement shall be confidential and will not be admissible as evidence in this or any other proceeding.

11. **Commission Procedure.** The obligations of the Parties under this Agreement are subject to the Commission's approval of this Agreement in accordance with its terms and conditions and upon such approval being upheld on appeal by a court of competent jurisdiction. The Parties will submit this Settlement Agreement to the Commission and

recommend approval in its entirety pursuant to RP 274. Parties shall support this Agreement before the Commission, and no Party shall appeal a Commission order approving the Agreement or an issue resolved by the Agreement. If this Agreement is challenged by any person not a party to the Agreement, the Parties to this Agreement reserve the right to file testimony, cross-examine witnesses, and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Agreement. Notwithstanding this reservation of rights, the Parties to this Agreement agree that they will continue to support the adoption of the terms of this Agreement.

If the Commission rejects any part or all of this Agreement, or imposes any additional material conditions on approval of this Agreement, each Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding, within 14 days of the date of such action by the Commission, to withdraw from this Agreement. In such case, no Party shall be bound or prejudiced by the terms of this Agreement, and each Party shall be entitled to seek reconsideration of an IPUC Order, file testimony as it chooses, cross-examine witnesses, and do all other things necessary to put on such case as it deems appropriate.

No Party shall be deemed to have agreed that any method, theory, or principle of regulation or cost recovery employed in arriving at this Agreement is appropriate for resolving any issues in any other proceeding in the future.

12. **<u>Entire Agreement</u>.** This Agreement and its attachments constitute the entire agreement between the Parties regarding the subject matter hereof. There are no oral or written understandings, representations, or commitments of any kind, express or implied, which are not expressly described in this Agreement.

13. **<u>Severability</u>**. If, after Commission approval of this entire Agreement without modification, any immaterial term or provision of this agreement that is found to be void, prohibited, or unenforceable by local, state, or federal law shall be ineffective only to the extent of such prohibition or unenforceability without invalidating the remaining provisions of this Agreement. Upon a determination that any material term or provision is void, prohibited, or unenforceable by local, state, or federal law, the Parties shall negotiate in good faith to modify this Agreement to maintain the original intent of the Parties without such material provision.

14. **<u>No Third-Party Beneficiaries</u>**. No right or obligation contained in this Agreement shall inure to the benefit of any person or entity not a Party or successor or assign of a Party.

15. **<u>Counterparts</u>**. This Agreement may be executed in counterparts and each signed counterpart shall constitute an original document.

[signature page follows]

DATED this ___day of September 2013.

Idaho Power Company

By Theresa Drake
Theresa Drake
Customer Relations & Energy Efficiency Manager

Idaho Public Utilities Commission Staff

By______________________________
Karl Klein
Deputy Attorney General

Idaho Irrigation Pumpers Association, Inc.

By______________________________
Sid Erwin
Vice President of IIPA

Idaho Conservation League

By______________________________
Benjamin J. Otto
Attorney for Idaho Conservation League

Snake River Alliance

By______________________________
Ken Miller
Clean Energy Program Director

EnerNOC, Inc.

By______________________________
Melanie Gillette
Director, Regulatory Affairs

By______________________________
Mike Seaman
Idaho Power Customer

DATED this 30th day of September 2013.

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Idaho Power Company	**Idaho Public Utilities Commission Staff**
By________________________ Theresa Drake Customer Relations & Energy Efficiency Manager	By________________________ Karl Klein Deputy Attorney General
Idaho Irrigation Pumpers Association, Inc.	**Idaho Conservation League**
By________________________ Sid Erwin Vice President of IIPA	By________________________ Benjamin J. Otto Attorney for Idaho Conservation League
Snake River Alliance	**EnerNOC, Inc.**
By________________________ Ken Miller Clean Energy Program Director	By Melanie Gillette Melanie Gillette Director, Regulatory Affairs

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Snake River Alliance

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Ken Miller
Clean Energy Program Director

EnerNOC, Inc.

By______________________________
Melanie Gillette
Director, Regulatory Affairs

By /S/ Mike Seaman
Mike Seaman
Idaho Power Customer