RILEY NEWTON
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0318
IDAHO BAR NO. 11202

Street Address for Express Mail:
11331 W CHINDEN BLVD, BLDG 8, SUITE 201-A
BOISE, ID 83714

Attorney for the Commission Staff

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR APPROVAL TO MODIFY ITS DEMAND RESPONSE PROGRAMS	**CASE NO. IPC-E-21-32** **COMMENTS OF THE COMMISSION STAFF**

STAFF OF the Idaho Public Utilities Commission, by and through its Attorney of record, Riley Newton, Deputy Attorney General, submits the following comments.

BACKGROUND

On October 1, 2021, Idaho Power Company ("Company") applied to the Commission for an order authorizing the Company to: (1) modify its demand response ("DR") programs; (2) implement associated revised tariff schedules; and (3) establish a revised cost-effectiveness method to evaluate its DR portfolio. The Company requested the Commission issue an order by February 15, 2022, to implement changes to the DR programs, which begin on June 15, 2022.

On December 21, 2021, the Commission provided notice of Modified Procedure, and set a February 10, 2022, public comment deadline and a February 17, 2022, Company reply deadline. Order No. 35266

The intent of the Company's DR programs is to minimize or delay the need to build a new supply-side resource to meet potential peak-hour system capacity deficits. While the potential deficits are expected to be significant, the Company believes they will be short in duration. Thus, the Company believes it may be cost-effective to utilize DR programs rather than building a new capacity supply-side resource that may only be required to operate for short periods of time. The Company indicates the DR maximum load reduction in the current programs represents 10 percent of the Company's system peak load.

The Company's DR portfolio uses three individual programs:

1. Residential Air Conditioner Cool Credit Program (Schedule 81);
2. Commercial & Industrial Flex Peak Program (Schedule 82); and
3. Irrigation Peak Rewards Program (Schedule 23).

Each program focuses on a specific customer group. Participants are paid a fixed incentive, and depending on the program, may be paid an additional variable incentive amount for the reduction in load during a DR called event.

The Company proposes to modify the DR programs by extending the program season by one month, from August 15 to September 15, and shifting the available DR event times by two hours later in the evening to improve system reliability during the highest-risk hours.[1] These changes, in addition to revisions to the DR programs' fixed and variable incentives, would be updated in each of the respective program tariffs. The Company also proposes to revise the cost-effectiveness methodology used as a benchmark in evaluating the economic benefit of the DR programs.

STAFF ANALYSIS

After reviewing the Company's Application and its response to discovery requests, Staff ultimately believes the Company should move forward with its proposal; however, Staff recommends the Company utilize a continuous improvement approach, reanalyzing needs and making adjustments and improvements as needs change. As electricity markets, the Company's resource mix, and customer needs change, the risk to system reliability increases and the need for modifications to the Company's DR programs becomes necessary. Given the near-term need to increase dispatchable capacity, as opposed to a lack of need in 2013, and a better understanding

[1] The Residential Air Conditioner Cool Credit program can be called during all hours of the day.

of the benefit of DR to system reliability, the terms of the 2013 Settlement Agreement approved by the Commission in Order No. 32923 are no longer relevant. Staff recommends the Commission approve the terms of the Company's proposal and declare that the design of the proposed programs supersede the terms of the 2013 Settlement Agreement entirely.

Staff's analysis as summarized in the following sections includes a review of: (1) the method to align the design of DR programs to the capacity needs of the system; (2) changes in the method for determining cost-effectiveness of the programs; (3) the method for determining the amount of DR potential that is available in the Company's system; (4) the frequency of impact evaluations; (5) the removal of the marketing cost cap; and (6) how the programs are managed in the future.

Alignment of DR Program Design to System Capacity Needs

The Company has shown the need to improve system reliability by extending the DR programs' season and shifting the hours later in the evening. During the development of the Company's 2021 Integrated Resource Plan ("IRP"), the Company made major modifications to the methods it uses to determines the load carrying capability of its resources and measure the reliability of its system. Relevant to DR, the Company now has the capability to measure the Loss-Of-Load Probability ("LOLP") for each hour over the IRP planning horizon, which allows the Company to determine the critical hours that the system needs DR in order to operate. The Company has also developed a method to determine the Effective Load Carrying Capability ("ELCC") of different DR program designs relative to the hours of most critical need. Through these new capabilities, the Company has shown that the existing DR programs as currently structured are no longer as effective in maintaining system reliability. Under current program parameters, the ELCC of the Company's current DR program is only 17 %, indicating that during the highest-risk LOLP hours, the DR program would only reliably provide 17 % of DR's maximum capacity.

The reason for the low ELCC is primarily due to the hours of the day and the length of the season that the program currently operates, which doesn't align with the most critical hours with the highest LOLP. The current programs operate between 1:00 pm and 9:00 pm and from June 15 through August 15.

However, given the amount of solar generation already available in the market and likely to be installed in the Company's service territory, the most critical hours are no longer at peak load, but rather when loads are near their peak and after the sun goes down, when solar is no longer available. Additionally, the Company has found that the most critical hours have also extended later into the season, primarily due to hotter, drier weather extending later into the summer months.

To address these issues, the Company proposes to extend the DR programs' season from August 15 to September 15 and shift the available DR hours later into the evening, to a 3:00 p.m. to 11:00 p.m. range. By modifying the DR programs in this way, the ELCC increases to 56 %, providing greater reliability to the system during the highest-risk LOLP hours.

The Company's approach first identifies the hours of greatest system need for capacity and then designs the DR programs to fit those needs, which Staff believes is a major improvement. The Company operates in a dynamic environment. As the environment and system needs change, the resources to supply those needs also need to change, thus Staff believes this approach should be regularly repeated. Staff recommends that the Company reanalyze the fit of its DR programs relative to system needs in every IRP.

Revised Cost-Effectiveness Methodology

The proposed cost-effectiveness methodology produces a value of DR relative to a least-cost simple cycle combustion turbine ("SCCT") proxy resource so that the Company can establish a cost threshold under which DR programs can measure cost-effectiveness within the Company's system. To ensure the benefits and the level of reliability provided by DR and by the proxy resource are equivalent, the Company made two modifications to its cost-effectiveness methodology. First, the Company quantified the additional benefits provided by a SCCT beyond what DR can provide then adjusted the avoided cost by this amount. Second, the Company determined the amount of DR nameplate capacity needed to provide an equivalent level of capacity contribution from a SCCT. The Company will perform a verification step to ensure that the amount of incremental DR included in the IRP preferred portfolio is cost effective compared to the surrogate using both adjustments. Ellsworth, DI at 23. Staff concurs with the proposed cost-effectiveness methodology and recommends this analysis be repeated in subsequent IRPs.

The SCCT proxy resource can provide benefits to the system beyond what DR can provide. A SCCT can operate 24 hours a day and throughout the entire year as compared to the redesigned DR programs, which are generally only dispatched from June 15 through September 15 and from the hours of 3 p.m. to 11 p.m. By running two Aurora simulations of the system, one with DR and the other with a SCCT, the Company was able to determine the value difference between the two resources. The Company determined that a SCCT provides approximately $38.11 per kilowatt ("kW") per year over and above a 492 megawatt ("MW") DR portfolio. This value was used to adjust the avoided cost of the SCCT proxy when determining the cost-effectiveness threshold. Staff believes the method used by the Company is robust and that this adjustment is necessary to ensure that the avoided cost using a proxy is accurate.

The level of capacity contributing to system reliability (effective load carrying capability) of the two resources, DR and a SCCT, are not equivalent for the same amount of nameplate capacity. The Company was able to determine that 272 MW of SCCT nameplate capacity is necessary to provide an equivalent amount of load carrying capability of 492 MW of DR nameplate capacity. These amounts were expressed as a ratio between the two amounts of nameplate and were used to adjust the avoided cost based on the fixed cost of a SCCT. As in the case of the benefit adjustment described above, this reliability adjustment is necessary to ensure that the avoided cost of the proxy resource is accurate.

Since the avoided costs and design of the programs are used as a basis for determining incremental amounts of DR to be included in the Company's IRP preferred portfolio, the Company has proposed a verification step to ensure that the incremental amounts of DR are cost-effective. The Company proposed an additional Aurora run replacing the DR programs in the preferred portfolio with an effective-equivalent SCCT so that the total cost of each run can be compared to ensure that the preferred portfolio reflects an equivalent or lower cost. Staff recommends this analysis be performed and the results provided in a compliance filing or in the next annual Demand-Side Management ("DSM") prudency filing. Staff also recommends that the full cost-effectiveness analysis discussed above be repeated in future IRPs.

Assessment of Available Demand Response

The Company estimates there is 492 MW of traditional DR potential for the Company's service territory based on the Northwest Power and Conservation Council ("NWPCC") assessment. The NWPCC assessment was conducted to determine the DR potential for the entire Northwest region for use in the NWPCC 2021 Power Plan. To derive the Company's DR potential for its service territory from the NWPCC region, the Company created a ratio of its system peak relative to the NWPCC region. Of the 31,125 MW system peak in the NWPCC region, the Company has an 11.89 % share. The Company then applied this ratio to the summer achievable potential for DR in the NWPPC region to determine the Company's MW allocation of DR potential for its service territory. The Company then adjusted its allocation of DR potential to factor in its existing programs while removing overlapping DR programs, high-cost programs, and programs with different ELCC's to achieve the 492 MW of DR potential specific to the Company's service territory.

While the Company tried to achieve an accurate estimate of DR potential for its service territory from this assessment, the best method for obtaining accurate results would have been to conduct a DR potential study specific to the Company's service territory as the Company's service territory is much different than that of the entire Northwest Region. For example, while the Company is a summer peaking utility with many irrigators on its system, other utilities in the Northwest are winter peaking utilities with service areas consisting of densely populated cities. Also, geographical differences between the Company's service territory and other regions of the Northwest could result in over or under estimating DR programs' potential for the Company's territory.

In Response to Staff's Production Request No. 3, the Company indicated it has selected a third-party contractor to conduct a DR potential study specific to the Company's service territory and anticipates work will begin in February 2022 with an estimated completion date near late summer or early fall. The contractor will consider any updated program parameters, participation levels, and incentives within its analysis. The updated participation levels of the current programs will be known in June. Staff believes this study will be beneficial and agrees that the process should focus on the Company's service area, program participants, and ratepayers. The Company's assumptions and calculations for the DR program and in the IRP should improve with the results of the study. Staff recommends the Company provide the Commission with results of the DR study and update calculations and assumptions in the Company's DR program as soon as the results of the study have been finalized and vetted for accuracy.

Impact Evaluations

The Company will also conduct internal evaluations and report results in its annual DSM report. The Company is planning to have a process evaluation completed in 2023 and third-party impact evaluations every five years thereafter. Staff interprets this response to indicate that five years would pass before impact of the DR changes will be fully analyzed and known. Staff recommends the Company conduct an impact evaluation as soon as sufficient program event data is available to conduct a meaningful evaluation for the DR program.

Marketing Cost Cap

Staff understands the Company's need to remove marketing cost constraints of DR programs. The 2013 Settlement was conducted in a much different planning environment than current circumstances given the Company's near-term need for capacity. Furthermore, because of the changes in hours and season that DR needs to operate, Staff agrees that it will be challenging to find customers willing to participate. Staff recommends that the budget cap on marketing expenses be removed, so long as the Company ensures that those costs are included in the cost-effectiveness calculations and that the programs remain prudent and cost-effective.

Staff intends to closely monitor the Company's marketing expenses for the DR program during the Company's annual DSM prudency filings. Marketing expenses should be limited and closely managed by the Company to ensure the DR program is a least cost option while remaining cost effective on a year-to-year basis.

Program Management

The Company's modification to the tariff language and establishment of a new cost-effectiveness method, supersedes the terms of the 2013 Settlement Agreement in Order No. 32923. It is Staff's expectation that the Company will actively manage its DR programs to ensure they remain cost effective as it does its other DSM programs. Staff recommends items including, but not limited to, the variable and fixed incentive values, minimum and maximum number of events, event window, event duration, program season, the proxy resource used, DR potential, and IRP results, should all be actively managed and updated to ensure continuous improvement of the program and that it remains cost-effective on a year-to-year basis. The Company is expected to become capacity deficient in 2023 and ensuring the DR program changes can meet the critical times and needs identified by the Company will be of the utmost importance.

Staff recommends the Company exercise one of the minimum events (if available) during the 2022 season between August 15 to September 15 and during the 9:00 p.m. to 11:00 p.m. event window to ensure the changes to the program can result in a significant amount of DR achieved so the Company can effectively plan on using the program during these critical times. In addition, Staff recommends the Company include in its annual DSM report updated information addressing the DR programs' effectiveness at meeting these times. Information such as DR achieved, opt outs, and realization rates should be included for the August 15 to September 15 period and during the 9:00 p.m. to 11:00 p.m. event windows.

STAFF RECOMMENDATIONS

Staff recommends the Commission:

1. Authorize the Company to modify its DR programs as described in the Application;
2. Approve Tariff No. 101 for Schedule 23 (Irrigation Peak Rewards Program), Schedule 81 (Residential Air Conditioner Cycling Program), and Schedule 82 (Flex Peak Program) with an effective date of February 15, 2022, as filed;
3. Authorize the Company's revised cost-effectiveness methodology to evaluate Demand Response as described in its Application to supersede the Settlement Agreement approved by Commission Order No. 32923 in its entirety;
4. Order the Company to analyze the fit of its DR programs relative to system needs and perform the cost-effectiveness equivalency analysis in every IRP;
5. Utilizing the needs analysis and cost-effectiveness equivalency analysis from the IRP, direct the Company to annually evaluate each of the DR programs to update key program characteristics to ensure the programs meet the needs of the system and remains cost-effective on a year-to-year basis;
6. Direct the Company to exercise one of the minimum events (if available) during the 2022 season between August 15 to September 15 and during the 9:00 p.m. to 11:00 p.m. event window; and

7. Eliminate the marketing cost caps and allow marketing cost necessary to promote participation as long as the cost are included in the cost-effectiveness calculations and the programs remain cost-effective.

Respectfully submitted this 10th day of February 2022.

Riley Newton
Deputy Attorney General

Technical Staff: Rick Keller
Kevin Keyt
Taylor Thomas
Travis Culbertson

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 10th DAY OF FEBRUARY 2021, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-21-32, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

LISA NORDSTROM
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: lnordstrom@idahopower.com
dockets@idahopower.com

CONNIE ASCHENBRENNER
RATE DESIGN SENIOR MGR
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: caschenbrenner@idahopower.com

ERIC L OLSEN
ECHO HAWK & OLSEN PLLC
PO BOX 6119
POCATELLO ID 83205
E-MAIL: elo@echohawk.com

LANCE KAUFMAN
AEGIS INSIGHT
4801 W YALE AVE
DENVER CO 80219
E-MAIL: lance@aegisinsight.com

PETER J RICHARDSON
RICHARDSON ADAMS PLLC
515 N 27TH ST
BOISE ID 83702
E-MAIL: peter@richardsonadams.com

DR DON READING
6070 HILL ROAD
BOISE ID 83703
E-MAIL: dreading@mindspring.com

BENJAMIN J OTTO
EMMA E SPERRY
ID CONSERVATION LEAGUE
710 N 6TH ST
BOISE ID 83702
E-MAIL: botto@idahoconservation.com
esperry@idahoconservation.com

ED JEWELL
DEPUTY CITY ATTORNEY
BOISE CITY ATTORNEY'S OFFICE
PO BOX 500
BOISE ID 83701-0500
E-MAIL: ejewell@cityofboise.org
boisecityattorney@cityofboise.org

JIM SWIER
MICRON TECHNOLOGY INC
8000 S FEDERAL WAY
BOISE ID 83707
E-MAIL: jswier@micron.com

AUSTIN RUESCHHOFF
THORVALD A NELSON
AUSTIN W JENSEN
HOLLAND & HART LLP
555 17TH ST STE 3200
DENVER CO 80202
E-MAIL: darueschhoff@hollandhart.com
tnelson@hollandhart.com
awjensen@hollandhart.com

ELECTRONIC ONLY
aclee@hollandhart.com
glgarganoamari@hollandhart.com

SECRETARY