BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JARED L. ELLSWORTH

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Jared L. Ellsworth and my business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Transmission, Distribution & Resource Planning Director for the Planning, Engineering & Construction Department.

Q. Please describe your educational background.

A. I graduated in 2004 and 2010 from the University of Idaho in Moscow, Idaho, receiving a Bachelor of Science Degree and Master of Engineering Degree in Electrical Engineering, respectively. I am a licensed professional engineer in the State of Idaho.

Q. Please describe your work experience with Idaho Power.

A. In 2004, I was hired as a Distribution Planning engineer in the Company's Delivery Planning department. In 2007, I moved into the System Planning department, where my principal responsibilities included planning for bulk high-voltage transmission and substation projects, generation interconnection projects, and North American Electric Reliability Corporation's ("NERC") reliability compliance standards. I transitioned into the Transmission Policy & Development group with a similar role, and in 2013, I spent a year cross-training with the Company's Load Serving Operations group. In 2014, I was promoted to Engineering Leader of the Transmission Policy & Development department and assumed leadership of the System Planning group in 2018. In early 2020, I was promoted into my current role as the Transmission, Distribution and Resource Planning Director. I am currently responsible for the planning of the Company's wires and resources to continue to provide customers with cost-effective and reliable electrical service.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to (1) inform the Idaho Public Utility Commission ("Commission")of recent improvements in the determination of the capacity contribution of supply-side and demand-side resources, developed as part of the 2021 Integrated Resource Plan ("IRP") planning process, and how such improvements have impacted the evaluation of Idaho Power's Demand Response ("DR") portfolio, (2) explain the analysis used to identify the proposed DR portfolio operating parameters using an enhanced risk-based methodology, and (3) describe how the economic value of the DR portfolio was determined and how that economic value was used to inform the program compensation modifications presented in this case.

## I. IRP CHANGES IMPACTING DEMAND RESPONSE EVALUATION

Q. Generally, how has DR been considered as a resource in the Company's planning process?

A. Historically, the Company has evaluated the maximum operational potential of its existing DR resources by their ability to meet the peak demand hour (peak load) during the summer months of June through August throughout the IRP planning horizon. This is consistent with how traditional supply-side resources have been evaluated.

Q. How did the methodology used to analyze the Company's capacity value of DR change following the 2019 IRP?

A. When determining the capacity value of the Company's DR portfolio in the 2019 IRP, the calculation was based on the DR portfolio's ability to be utilized during the top one-hundred system load hours given the program parameters.

Moving into the 2021 IRP planning process, the Company adopted a risk-based methodology, known as Effective Load Carrying Capability ("ELCC"), to evaluate the capacity contribution of the Company's existing resources, expected future resources (including variable resources), and DR. This method evaluates the Company's load and resource balance at the time of the highest-risk hours, rather than only analyzing a resource's ability to meet peak load.

Q. Why is the Company proposing to evaluate its load and resource balance using the ELCC risk-based methodology rather than the capacity planning method based on system peak load?

A. As previously mentioned, Idaho Power's planning process historically focused on ensuring adequate resources were available to meet the overall system peak load. Due to the penetration of solar, wind, and other variable resources connected to the Idaho Power system, the primary hours of need for additional resources, or the highest-risk Loss-of-Load Probability ("LOLP") hours, are no longer expected to align with the hours of Idaho Power's system peak load.

Q. What is LOLP?

A. LOLP is the statistical likelihood, between zero and one, of the system demand exceeding the available generating capacity during a given time period, typically an hour. The LOLP for an hour can be calculated by comparing the system net load to a statistically derived resource capacity probability distribution curve for any given hour. The resource capacity probability distribution curve is the probability (based on resource capacities, historical resource availability, and statistical forced outage rates) the Company will have more than a certain amount of generation available to it at any given time.

Q. What is net load?

A. Net load is the total system load minus any non-controllable resources, i.e., generation that is either (1) not controlled by Idaho Power, or (2) has limited or zero flexibility. Examples of generation resources Idaho Power does not have operational control over are wind, solar, and PURPA resources. Run-of-river hydro is an example of a resource with limited flexibility.

Q. How do the highest-risk LOLP hours compare to the time of the system peak load?

A. In the preliminary 2021 IRP analyses, the highest-risk LOLP hours have been shown to shift to later in the day when solar sees an output reduction. As more solar comes on to the Company's system, the Company expects the LOLP of the evening solar-ramping-hours to increase and drive the need for additional resources later in the day.

Charts 1 through 4 depict Idaho Power's LOLP hours under various solar resource scenarios and how the highest-risk hours begin to shift as more solar is added to the system. While the time of the Company's system peak load has historically occurred between 5:00pm and 8:00pm, the highest-risk hours are expected to occur between 7:00pm and 10:00pm, with some medium-risk hours leading up to 7:00pm and from 10:00pm to 11:00pm, over the 2021 IRP planning horizon.

Chart 1 reflects July’s hourly LOLP with no solar resources. The highest-risk hours are between 3:00pm and 8:00pm.

**Chart 1. July LOLP - Test Year 2 Shape – No Solar Resources and No Demand Response**

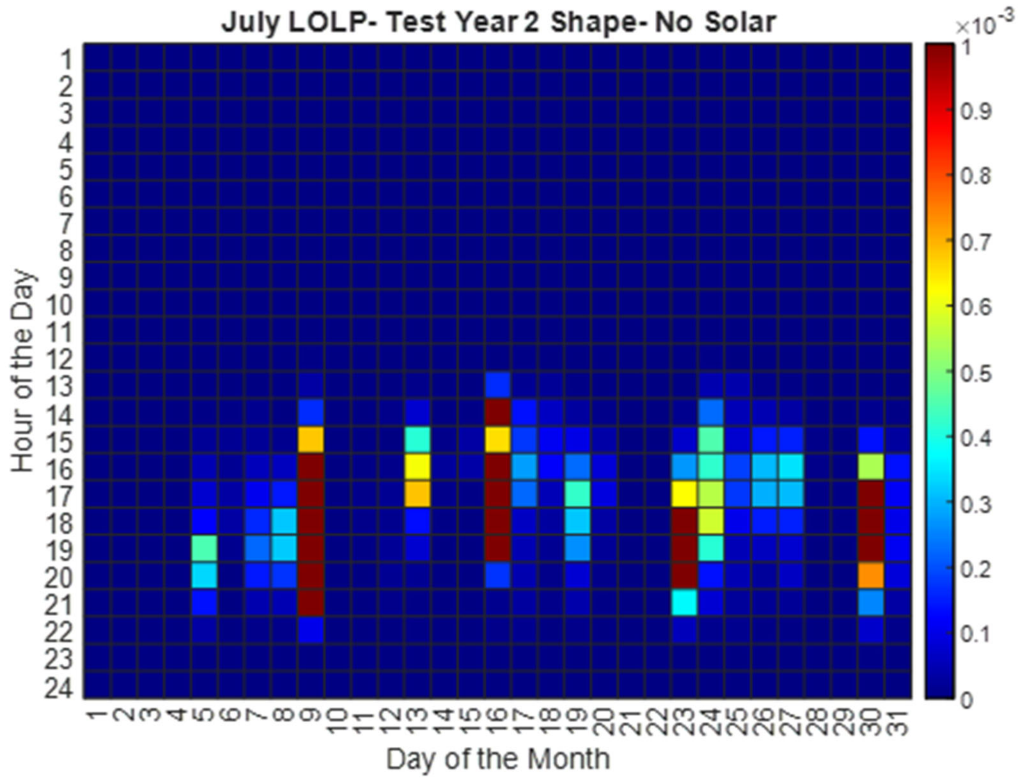


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Chart 2 reflects July's hourly LOLP with 316 Megawatts ("MW") of solar resources on the system, which is reflective of the current solar capacity in 2020. The highest-risk hours of need shift later in the day from 4:00pm to 9:00pm.

**Chart 2. July LOLP - Test Year 2 Shape – 2020 Solar Resources and No Demand Response**

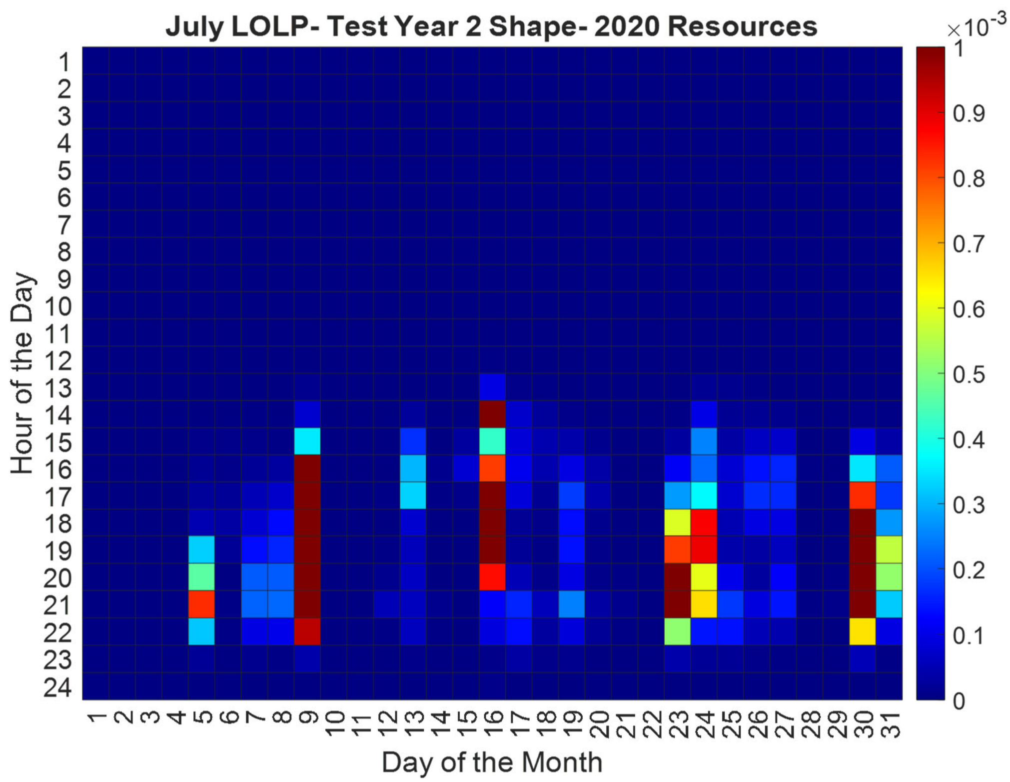


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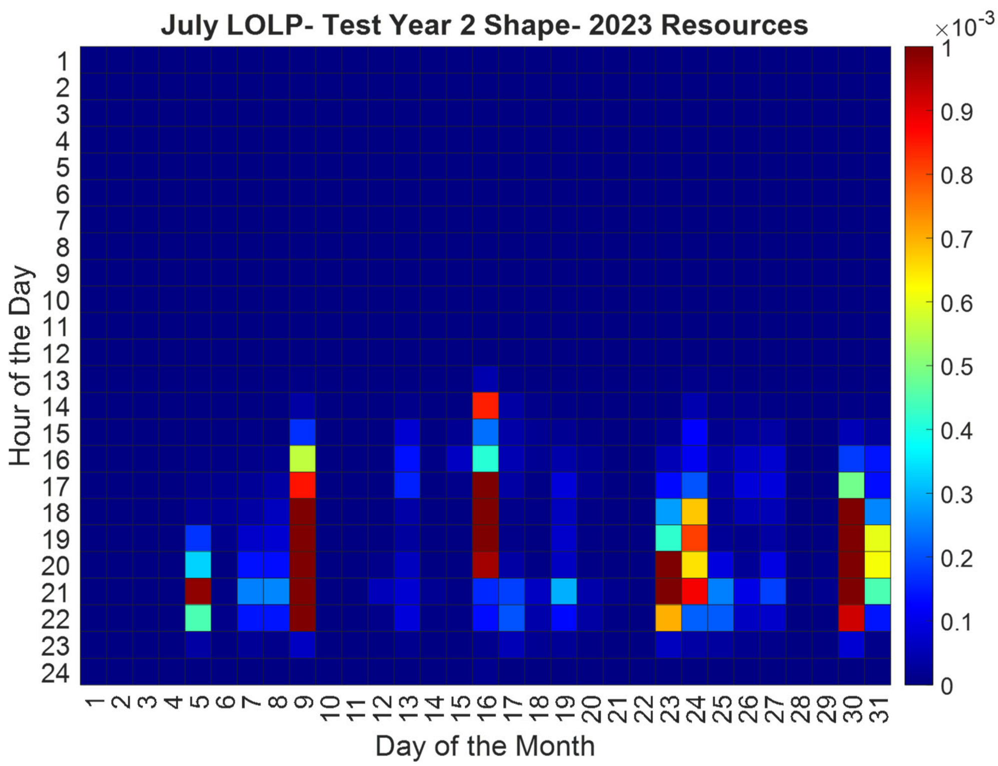
Chart 3 reflects July's hourly LOLP with 436 MW of solar resources on the system, which includes the 120 MW expected from the Jackpot Solar Project in 2023. The highest-risk hours continue to shift later in the day, moving to 5:00pm to 10:00pm. This scenario also shows the 10:00pm and 11:00pm hours starting to have a higher risk probability.

**Chart 3. July LOLP - Test Year 2 Shape – 2023 Solar Resources and No Demand Response**

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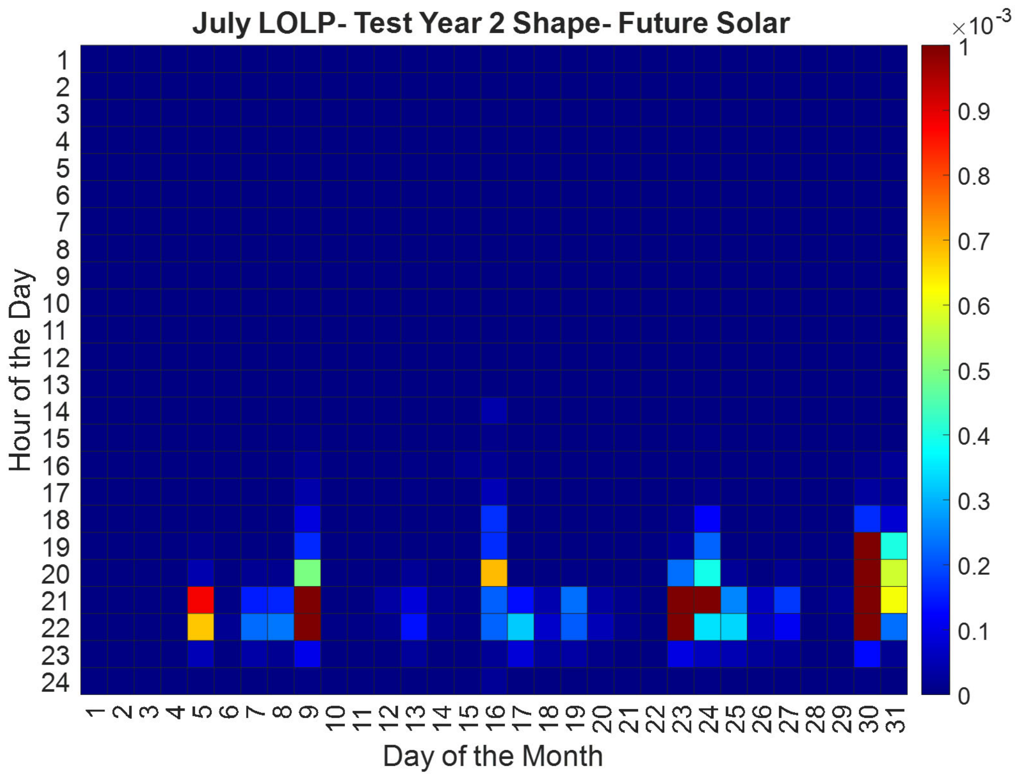
Finally, Chart 4 reflects July’s hourly LOLP with 836 MW of solar resources on the system, which includes 400 additional MW as compared to the connected 2023 solar capacity and is potentially reflective of the future system as solar becomes more prevalent. The highest-risk hours really condense into the later hours of the day.

**Chart 4. July LOLP - Test Year 2 Shape – Future Solar and No Demand Response**

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Q. Why does the Company believe the ELCC method is appropriate for resource planning purposes?

A. The assumption that the highest-risk hours of capacity shortfall directly correspond with the hours of highest load is only valid for a system with little or no variable resource penetration. With the Company's existing resources, and the projected additions of more variable resources coming onto the system, the hours of highest-risk will not necessarily align with the hours of highest load. The Company believes that the ELCC method accurately captures the Company's future resource adequacy risks. The ELCC method still considers DR's ability to contribute capacity given the program parameters, but the hours of need are identified using probabilistic and statistical methods as opposed to utilizing the top one-hundred system load hours.

Q. How is ELCC applied in the resource planning process?

A. ELCC is a reliability-based metric used to determine the peak capacity credit of any given resource and captures an individual generator's contribution to overall system reliability. It is primarily driven by the timing of high-risk LOLP hours. For example, a generator that contributes a significant level of capacity during high-risk LOLP hours will have a higher ELCC than a resource that delivers the same capacity during medium to low-risk LOLP hours. Utilizing multiple test years, ELCC values are determined and assigned to existing and selectable resources in the Aurora model for different scenarios, sensitivities, and portfolios in the IRP.

Q. How is ELCC used to calculate the capacity contribution of various resources?

A. The ELCC of a resource is determined through a multi-step process. First, the Company calculates the perfect generation, in MW, required for the system to achieve a Loss-of-Load Expectation ("LOLE") of 0.05 days per year with all market purchases set equal to zero. An LOLE of 0.05 days per year represents the statistical probability that the Company's available generation capacity is only insufficient to serve demand one time in the span of twenty years. Next, the resource being evaluated is added to the system and the Company once again calculates the perfect generation required to meet the same LOLE threshold. The perfect generation of the system with the resource is subtracted from the perfect generation of the system without the resource and then divided by the evaluated resource's nameplate capacity to obtain the resource's ELCC as shown in the equation below.

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$$\mathbf{ELCC} = \frac{\mathbf{PG_1} - \mathbf{PG_2}}{\mathbf{Resource_{NP}}}$$

$$\mathbf{PG_1} = \textbf{Perfect generation required to achieve LOLE of 0.05 days/year without including evaluated resource}$$
$$\mathbf{PG_2} = \textbf{Perfect generation required to achieve LOLE of 0.05 days/year when including evaluated resource}$$
$$\mathbf{Resource_{NP}} = \textbf{Nameplate capacity of the evaluated resource}$$

Q. What is the difference between LOLP and LOLE?

A. LOLP identifies high and low-risk hours in regards to system load exceeding generation capacity, and the maximum LOLP from each day over the course of 365 days are summed together to calculate the LOLE.

Q. What is an Equivalent Forced Outage Rate ("EFOR") and how is it incorporated into the ELCC methodology?

A. An EFOR represents the number of hours a generation unit is forced off-line compared to the number of hours the unit runs (planned maintenance is not factored into a unit's EFOR). For example, an EFOR of 3 percent means a generator is forced off, or incurs an unplanned outage, 3 percent of its running time. A perfect generator is a generation unit whose EFOR value is 0 percent, meaning that it is always available and never forced off-line. A perfect resource does not actually exist in practice, but it is used as a "standard" to enable ease of comparison between different generation options.

Q. What LOLE threshold is the Company planning to utilize in the 2021 IRP?

A. In the 2021 IRP, the Company will plan for an LOLE threshold of 0.05 days per year, which represents a statistical probability of the Company being resource insufficient one day in twenty years. The two primary reasons the Company ultimately chose to plan for a 0.05 days per year LOLE threshold are:

(1) The Company operates a power system highly dependent on hydroelectric resources, which can vary dramatically from year-to-year due to water conditions. A poor water year can significantly affect hydroelectric resource availability, especially during summer months.

(2) The LOLE methodology utilizes historical data to make forward looking decisions. Recently, weather extremes have been occurring with greater frequency. Therefore, by planning for an LOLE of 0.05 days per year, the Company expects to be able to maintain a similar level of reliability that Idaho Power's customers and regulators expect moving forward.

Q. How are different resource types modeled in the LOLE calculation?

A. Idaho Power's resources are split into three primary categories: dispatchable resources, non-controllable resources, and energy-limited resources.

Idaho Power's dispatchable resources include the Hells Canyon Complex, natural gas plants, Bridger and Valmy coal plants, and various transmission assets. These resources are modeled using a monthly outage table that factors in their generating capacities and EFORs.

Non-controllable resources are modeled by using four years of historical hourly output data to provide realistic weather shapes. Non-controllable resources are resources for which Idaho Power does not have direct operational control over such as wind, solar, dairy digestors, non-wind and non-solar PURPA projects, run-of-river hydroelectric plants, and geothermal generation.

Dispatch shapes for energy-limited resources such as battery storage and DR are created based on net load explained later in my testimony.

Q. What did the Company find when evaluating its existing DR programs utilizing the ELCC method?

A. The existing DR programs, as structured, are not effective at meeting system needs over the planning horizon. As more fully described below, certain parameters of the existing programs, specifically the current dispatch hours and the program season, limited the effectiveness of DR as a resource.

## II. PROPOSED DEMAND RESPONSE PROGRAM PARAMETERS

Q. How were the existing DR programs evaluated using the LOLP and ELCC methodology?

A. Idaho Power conducted the ELCC analysis on the current DR programs to identify how effective they are at meeting future high-risk LOLP hours.

The ELCC of DR was calculated using a multi-step process. First, every day in a test year was sorted from highest to lowest based on their net peak load in MW. Second, a daily MW target was set for each day based on the highest net load hour within the day and the size of the dispatchable DR group. The Company determined that an approximate 50 MW group size results in a capacity amount that is operationally manageable yet still large enough to have a meaningful impact on reducing system load. It also most closely aligns with how Idaho Power's Load Serving Operations group dispatches the programs.

After sorting the days and establishing a daily target, the analysis identified if the day was within the DR season's start and end dates and if the day was not a weekend or holiday. If the day met the DR program parameters, the algorithm would analyze each hour of the day and compare the hourly net load with the daily target. If the net load was above the target, the function would dispatch DR MW groups in that hour. The algorithm then iterates over the remaining hours in that day until DR had been dispatched to reduce the net load for each of the hours initially above the daily target, or DR capacity had been exhausted. After completing one day, the algorithm re-sorts all of the remaining days in the test year by net peak load and repeats the process. In this manner, the algorithm dispatches the DR programs in a way that maximizes their usage and effectiveness. The algorithm lastly creates a dispatch pattern by adding all the groups into a single load shape.

The ELCC of DR is obtained by first determining the perfect generation needed to achieve an LOLE of 0.05 days per year without any DR on the system. Next, the DR load shape derived using the algorithm described above is added to the system, and the perfect generation is calculated again. The ELCC of DR is then calculated by taking the difference between the two perfect generation values and dividing it by the DR portfolio’s nameplate capacity.

Q Describe the algorithm the Company utilized in the analysis.

A. The Company internally developed the LOLE MATLAB® algorithm within the MATLAB® software it is utilizing for the IRP planning process. The algorithm is computationally intensive, composed of several scripts, and requires specialized software to effectively and accurately run the calculations that model Idaho Power’s existing and future resources.

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Q. What was the result of the ELCC analysis for the Company’s existing DR programs?

A. Using the current program parameters, the ELCC of a 380 MW DR portfolio is estimated to be approximately 17 percent. That is, of the total 380 MW DR portfolio capacity, only 65 MW can be relied upon to meet the highest-risk LOLP hours. The analysis was completed by evaluating the current DR programs over four historical test years. The historical test years were used for weather shaping, scaled to have the same peak load as the forecasted 2023 system peak, and included the known solar resources that will be online in 2023 such as the 120 MW Jackpot Solar Project.

Table 1 below shows the resulting ELCC value for each test year and the average value across those years. Based on this analysis, and given the current program parameters, the current DR portfolio is expected to only be 17 percent effective in meeting high-risk LOLP hours.

**Table 1. Current Demand Response Program ELCC**

| Test Year | Current Demand Response ELCC (%) |
|---|---|
| Test Year 1 | 14.21% |
| Test Year 2 | 33.20% |
| Test Year 3 | 12.10% |
| Test Year 4 | 7.90% |
| Average | 16.84% |

Q. How were the proposed DR program parameters determined?

A. Recognizing that the existing program parameters may limit the effectiveness of DR, the Company conducted several sensitivity analyses to determine the parameter adjustments needed to more effectively meet high-risk LOLP hours. These analyses were performed by modifying several program criteria and evaluating the impact to the ELCC of the DR portfolio. The program criteria studied for each program included events per week, events per season, time available, length of program season, and total hours dispatched per week.

Q. What DR program parameters did the Company conclude will more effectively meet future high-risk LOLP hours?

A. The sensitivity analyses concluded that the dispatch times available and the length of program season were the two parameters that had the highest impact on the ELCC of DR. Therefore, the proposed parameters that more effectively meet future high-risk LOLP hours were determined as outlined in Table 2 below.

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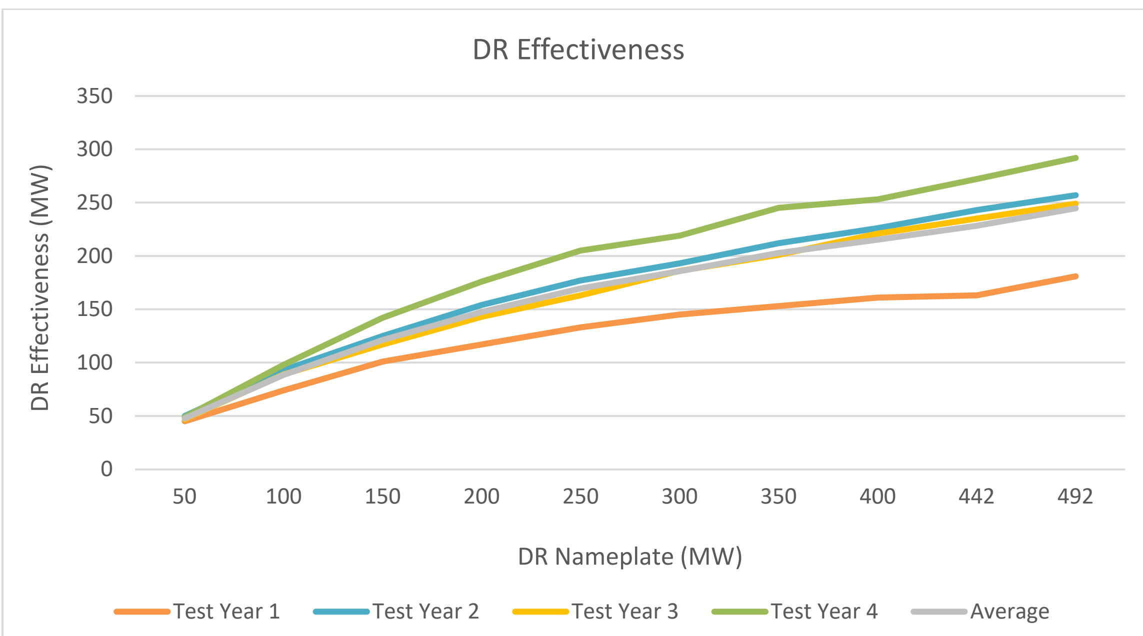
**Table 2. Current and Proposed Demand Response Program Parameters**

| Parameter | Current Parameters | Proposed Parameters |
|---|---|---|
| Events per Week | 15 hours | 16 hours |
| Events per Season | 60 hours | 60 hours |
| Time Available | 1:00pm to 9:00pm | 3:00pm to 11:00pm |
| Season Dates | June 15th to August 15th | June 15th to September 15th |
| Holidays | No holidays | No holidays |

Q. Did Idaho Power analyze the effectiveness of varying levels of DR capacity?

A. Yes. As shown in Chart 5, the Company analyzed the effectiveness of DR capacity in 50 MW increments. The chart shows that DR effectiveness, and therefore ELCC, diminishes as DR nameplate capacity increases.

**Chart 5. DR Effectiveness vs DR Nameplate Capacity**

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Q. What is the ELCC of the DR portfolio using the proposed parameters?

A. The ELCC of DR is dependent on the nameplate capacity of the program as shown in Chart 5. While the nameplate of the proposed DR portfolio is still unknown, the Company estimates the approximate ELCC of a DR portfolio with the proposed parameters to be 56 percent with a 380 MW nameplate capacity. This would be approximately a 40 percent improvement in effectiveness from the current program parameters. As mentioned earlier, the main drivers of the increased effectiveness are the shift in the dispatch time period and extending the program season by one month to September 15th.

## III. COST-EFFECTIVENESS COMPONENTS

Q. Please explain how the primary inputs to the proposed economic evaluation described in Mr. Nesbitt's testimony were determined.

A. The three components of the proposed alternative cost calculation are (1) the levelized capacity fixed costs of a proxy resource, (2) the additional system benefits of the proxy resource, and (3) the ELCC of the annual DR nameplate capacity compared to a proxy resource.

Q. Describe how the value of the levelized capacity fixed costs of a proxy resource was determined.

A. The proxy resource used to evaluate the cost-effectiveness of the proposed DR programs was a Simple-Cycle Combustion Turbine ("SCCT"). Through the 2021 IRP resource costing process, the 2022 levelized fixed cost value was determined to be $131.60 per kW per year. This value represents the fixed cost per kW per year if the Company were to build the SCCT instead of running the DR programs.

Q. Describe how a value for the additional system benefits of the proxy resource is determined.

A. Because an SCCT is not restricted to operate for only a defined number of hours like DR, it provides additional benefits and reliability to the Company's system. To determine the approximate value of the additional benefit, the Company completed a Production Cost Model ("PCM") in Aurora by including the SCCT and DR in two separate runs of a 2019 IRP PCM subset. The additional system benefits of the SCCT over the first 5 years of the planning horizon equated to $38.11 per kW per year compared to an equally effective 492 MW DR portfolio. The Company believes calculating the additional benefit value is important because it identifies the economic value a supply side resource has beyond the system benefits DR can provide.

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Q. Describe how the ELCC of the annual DR nameplate capacity compared to a proxy resource is determined.

A. The ELCC of the annual DR nameplate capacity is calculated by first obtaining the amount of perfect generation displaced by the proposed DR programs, i.e. DR's perfect resource effectiveness. An SCCT is not a perfect generator and has an EFOR greater than zero. By using the same ELCC methodology, but factoring in an SCCT's EFOR, the Company can determine the size of an effective-equivalent SCCT to the DR portfolio's perfect resource effectiveness. The $ELCC_{SCCT}$ of the DR programs is calculated by taking the quotient between the capacity of the effective-equivalent SCCT and the DR nameplate capacity. Using a 492 MW DR portfolio, the effective equivalent SCCT's nameplate was determined to be 272 MW based on the Company's projected 2023 load and resource balance. This results in an $ELCC_{SCCT}$ of 55 percent given a DR portfolio capacity of 492 MW (272 MW ÷ 492 MW = 55%).

Q. Why is the Company utilizing 492 MW as the maximum nameplate DR in its economic evaluation analysis?

A. The Company utilized a Northwest Power and Conservation Council ("NWPCC") assessment[1] of DR potential

[1] 2021 Northwest Power Plan Supporting Material – Demand Response. Council Document 21-5 (September 2021) available at https://www.nwcouncil.org/2021powerplan_demand-response

for the Northwest region to determine the DR potential that may be available in Idaho Power's service area. The Company concluded that Idaho Power's service area has 584 MW of DR potential as shown in Exhibit 1 to my testimony. From the 584 MW of potential, the Company determined that 492 MW would have similar program parameters such as seasonal restrictions, hours per year, etc. Therefore, 492 MW of traditional nameplate DR can be modeled using the same ELCC methodology, and the results can be utilized to establish programs and incentives that will remain cost-effective as the size of the DR portfolio changes over the planning horizon.

Q. Will the Company perform any additional analysis to validate the value of DR in the 2021 IRP?

A. Yes. The Company intends to perform an updated analysis to validate that DR provides system value. The Company intends to run a PCM in Aurora with the proposed DR programs through the IRP planning horizon. This PCM will be based on the preferred portfolio in the Company's 2021 IRP. A second PCM run will be performed that will replace the proposed DR programs with an effective-equivalent SCCT. The total PCM cost over the time horizon will be compared between the two runs. The extra benefit that the SCCT provides (in dollars per kW per year) will be calculated by taking the difference of the run with the effective-equivalent SCCT and the run with the proposed DR portfolio each year and dividing it by the capacity of the effective-equivalent SCCT.

Q. Has the Company determined how it will evaluate existing and expanded DR in future IRPs?

A. Yes. Through the coordination of both this filing and the upcoming 2021 IRP filing, the Company has determined that for the 2021 IRP, it will evaluate DR in the IRP modeling process by utilizing the 584 MW of DR potential identified in the NWPCC assessment.

The 584 MW of DR potential will consider a conservative estimate of 300 MW of capacity from the modified DR programs. Therefore, a maximum of approximately an additional 280 MW of DR (584-300 MW rounded down) will be available for selection in the Aurora model when analyzing the future load and resource balance. The additional DR capacity will be divided into 20 MW bundles and available for selection up to the 280 MW threshold.

For future IRPs, the Company intends to evaluate the possibility of conducting an Idaho Power specific potential study to evaluate the DR potential in its service area.

Q. How did the Company determine the 300 MW of DR capacity to be included as a committed resource in the 2021 IRP analysis?

A. Because the Company's DR programs are existing resources that have been included in past IRP analyses, the Company needed to determine a committed capacity value for inclusion in the 2021 IRP model. As described in Mr. Nesbitt's testimony, the Company expects there will be an impact to DR participation as a result of the proposed parameter changes. Therefore, the Company took a conservative approach by adjusting the current 380 MW capacity of the DR programs to 300 MW.

If the DR portfolio was to have a nameplate capacity of 300 MW, the ELCC of the DR portfolio would increase to 63 percent from 56 percent with a 380 MW DR portfolio. Table 3 below shows the ELCC for each test year and the average across those years for a DR portfolio with the proposed parameters and a capacity of 300 MW.

**Table 3. Proposed Demand Response Portfolio ELCC (300 MW Capacity)**

| Test Year | Proposed Demand Response ELCC (%) |
|---|---|
| Test Year 1 | 51.33% |
| Test Year 2 | 64.00% |
| Test Year 3 | 62.00% |
| Test Year 4 | 74.33% |
| Average | 62.92% |

A 300 MW DR portfolio will result in a 189 MW capacity contribution to the 2022 load and resource balance (300 MW x 62.92% = 189 MW).

Q. How will the Company proceed if the IRP selects the 20 MW bundles of additional DR for the future load and resource balance?

A. If the 2021 IRP model selects additional 20 MW DR bundles in future years, the Company will work internally, and with the Energy Efficiency Advisory Group, to determine the best course of action on DR expansion. The Company will evaluate potential options such as increasing the capacity of current DR programs or adding new programs to the Company's DR portfolio.

## IV. CONCLUSION

Q. Please summarize your testimony.

A. The Company has applied an enhanced risk-based capacity planning methodology to determine new proposed operating parameters that will greatly improve the ability of DR to meet future high-risk LOLP hours. The Company then built upon this new planning methodology to develop a proposed economic valuation calculation to inform program compensation levels and cost-effectiveness. The Company believes that the enhanced analysis has identified changes that improve the DR programs to the benefit of customers, the system, and meeting future resource needs.

Q. Does this complete your testimony?

A. Yes, it does.

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**DECLARATION OF JARED L. ELLSWORTH**

I, Jared L. Ellsworth, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Jared L. Ellsworth. I am employed by Idaho Power Company as the Transmission, Distribution & Resource Planning Director for the Planning, Engineering & Construction Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit No. 1 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibit are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of October 2021, at Boise, Idaho.

Signed:

## IPC Demand Response Potential Analysis Based on NWPCC's Draft 2021 Northwest Power Plan (September 2021)

### IPC Potential Based on Program Type

| Product | 2041 NWPCC Ramped Achievable Potential MW by Year by Product | Idaho Power MW Allocation[1] |
|---|---|---|
| ResCPP | 251.4 | 29.9 |
| ComCPP | 134.1 | 15.9 |
| IndCPP | 108.7 | 12.9 |
| IndRTP | 24.2 | 2.9 |
| ResERWHDLCGrd | 867.3 | 103.1 |
| ResERWHDLCSwch | 76.5 | 9.1 |
| ResBYOT | 63.1 | 7.5 |
| NRCoolSwchMed | 48.1 | 5.7 |
| NRTstatSm | 23.0 | 2.7 |
| NRCoolSwchSm | 15.2 | 1.8 |
| NRIrrSmMed | 464.0 | 55.2 |
| NRIrrLg | 393.7 | 46.8 |
| ResACSwch | 194.1 | 23.1 |
| NRCurtailInd | 174.1 | 20.7 |
| NRCurtailCom | 38.7 | 4.6 |
| DVR | 560.9 | 66.7 |
| ResTOU | 214.0 | 25.4 |
| ResEVSEDLCSwch | 72.3 | 8.6 |
| ResHPWHDLCGrd | 6.3 | 0.7 |
| ResHPWHDLCSwch | 0.8 | 0.1 |
| **MW Total** | **3,730** | **443** |

### Adjusted IPC Potential Based on Program Type[2]

| Product | Summer Achievable Potential (MW) | Idaho Power MW Allocation[3] |
|---|---|---|
| ResCPP | 251.4 | 29.9 |
| ComCPP | 134.1 | 15.9 |
| IndCPP | 108.7 | 12.9 |
| IndRTP | 24.2 | 2.9 |
| ResERWHDLCGrd | 867.3 | 103.1 |
| ResERWHDLCSwch | 76.5 | 9.1 |
| ResBYOT | 63.1 | 7.5 |
| NRCoolSwchMed | 48.1 | 5.7 |
| NRTstatSm | 23.0 | 2.7 |
| NRCoolSwchSm | 15.2 | 1.8 |
| NRIrrSmMed | 0.0 | 0.0 |
| NRIrrLg | 0.0 | 0.0 |
| ResACSwch | 0.0 | 0.0 |
| NRCurtailInd | 0.0 | 0.0 |
| NRCurtailCom | 0.0 | 0.0 |
| DVR | 560.9 | 66.7 |
| ResTOU | 214.0 | 25.4 |
| ResEVSEDLCSwch | 0.0 | 0.0 |
| ResHPWHDLCGrd | 0.0 | 0.0 |
| ResHPWHDLCSwch | 0.0 | 0.0 |
| **MW Total** | **2,386** | **284** |

| IPC DR Potential Allocation | NWPPC Region (MW) | IPC Service Area (MW) | IPC Allocation Ratio (%)[4] |
|---|---|---|---|
| System Peak | 31,125 | 3,700 | 11.89% |
| DR Potential | 2,386 | 284 | n/a |

**Potential (MW)**

| | | |
|---|---|---|
| IPC Estimated Minimum DR Capacity with Proposed Changes | | 300 |
| IPC Service Area DR Potential | + | 284 |
| **IPC DR Total Potential** | | **584** |
| Possible Future Programs with Different ELCC[5] | - | 92 |
| **IPC Traditional DR Potential** | | **492** |

**Legend**

| |
|---|
| Pricing Program |
| Possible Future Program |
| Current IPC Program |
| Possible Future Program with different ELCC |
| High Cost Program |

(1) Multiplied by 11.89% allocation ratio

(2) Removes potential from current IPC programs and programs considered to be high cost

(3) Multiplied by 11.89% allocation ratio

(4) Calculated by taking IPC's proportion of the region's system peak (3,700÷ 31,125 = 11.89%)

(5) DVR + ResTOU = Future Programs with Different ELCC (66.7 + 25.4 = 92.1)