MATT HUNTER
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0318
IDAHO BAR NO. 10655

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 OF THE CAPACITY DEFICIENCY TO BE UTILIZED FOR AVOIDED COST CALCULATIONS	**CASE NO. IPC-E-21-09** **REDACTED COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's Application.

BACKGROUND

On April 9, 2021, Idaho Power Company ("Company") applied for Commission approval of its capacity deficiency period determination for avoided cost calculations under the Public Utility Regulatory Policies Act of 1978 ("PURPA").

Under PURPA, the Commission has established a surrogate avoided resource ("SAR") method and an integrated resource plan ("IRP") method to calculate avoided cost rates for qualifying facilities ("QFs"). Under both methods, a QF receives capacity payments only after the applicable capacity deficit date is reached. Order Nos. 33377, 33159, and 33898. The first deficit date under the IRP method will float (change) to reflect the changes in the QF queue, while the first deficit date under the SAR method will not float to reflect the changes in the QF queue. Order No. 33933.

The capacity deficiency period is determined through the IRP planning process and is submitted to the Commission in a proceeding separate from the IRP docket. The capacity deficit date determined in the IRP process is presumed to be correct as a starting point but will be subject to the outcome of the capacity deficiency case. Order No. 32697.

In its Application, the Company anticipates its capacity deficiency period will begin in August 2028 and explains how this capacity deficiency period was calculated. To calculate its capacity deficiency period for PURPA avoided cost calculations, the Company explains that its "load and resource balance has been determined based on the [Company's] system as modeled in the 2019 IRP." Application at 3; *see* Case No. IPC-E-19-19, Order No. 34959 (acknowledging the Company's 2019 IRP). The Company asks that the Commission approve the capacity deficiency period.

STAFF ANALYSIS

Staff examined the load forecast and resources in the load and resource balance ("L&R") filed in this case. The L&R is used to determine the proposed capacity deficiency date used in both the IRP and SAR methods. Based on its analysis, Staff recommends the Company update the L&R and the resulting capacity deficiency date by incorporating the following changes:

- Use the most recent load forecast developed by the Company because the proposed load forecast does not reflect current economic conditions;
- Reduce the amount of Market Purchases <u>from southern pathways</u> by 310 MW and only include 50 MW starting in 2021;
- Allow non-PURPA PPAs to expire on their actual expiration dates;
- Reflect contract changes since the preparation of the L&R, which include PURPA contract updates identified in Response to Staff's Production Request No. 7 and approval of the Jackpot Solar contract; and
- Correct the capacity values of the Valmy Unit 2 and Jim Bridger ("Bridger") generating facilities.

If Staff's recommendations are authorized by the Commission, Staff proposes to update published rates on the Commission's website after the Company files an updated L&R and capacity deficiency date through a compliance filing. Furthermore, Staff recommends that a generic docket be opened to determine the timing of the deficiency date filing in relation to the timing of the IRP. This will allow the utilities, other parties, and Staff to weigh the pros and cons of different filing schedules. Details for each of the recommendations are contained in the following sections.

Deficiency Date Filing Timing and Notice of Intent

The deficiency date in this filing is based on the information used to develop the L&R from the Company's 2019 IRP. In Order No. 33917, the Commission decided to change when the utilities file their bi-annual first deficiency date updates until after the Commission acknowledged their IRPs based on Staff's recommendation. Staff's recommendation and the Commission's decision were based on ensuring a full review of the IRP so that any findings through the IRP review that affects L&R could be incorporated into the analysis of the deficiency date when the case was filed. However, this change in timing, exacerbated by the Company's delay in processing the 2019 IRP, has caused a larger than usual overlap in timing with the start of the 2021 IRP cycle prior to the 2019 IRP acknowledgment.[1]

The overlap in timing and the practice of updating information, such as the load forecast, recent long-term contracts, and non-method driven inputs using the most recent IRP as a starting point,[2] has caused unintended consequences as it relates to the Company's Notice of Intent for an All-Source Request for Proposals ("NOI") announced in May 2021. The need for the NOI is driven by information and preliminary analysis that the Company has performed as part of the 2021 IRP, not the 2019 IRP. This has caused some apparent contradictions between the timing and need for resources in this filing versus the need and timing of resources in the NOI. Because of these contradictions, Staff's investigation separated the different drivers precipitating the NOI to determine which of those drivers and related data should be used to update the L&R and the deficiency date for this filing versus those items that should be evaluated in the next deficiency

[1] The Second 2019 Amended IRP was not filed until October 2, 2020, about 15 months after it normally would have been filed. It was acknowledged on March 16, 2021.

[2] Order No. 32697, p. 23 states that the "capacity deficiency determined through the IRP planning process will be the starting point, and will be presumed to be correct subject to the outcome of the [capacity deficiency date case] proceeding." This is further reinforced in Order No. 33958 which states, 'Recognizing that IRPs are long-term plans that are "flexible and responsive to its customers' needs over time,' [Order 32697 at 23] we find it appropriate for a utility to use the most updated information available in calculating its capacity deficit date."

date case associated with the 2021 IRP after it has been acknowledged. Through responses to discovery requests, Staff has identified the primary drivers of the NOI which are (1) load growth, (2) availability of firm transmission to access purchases from the market, and (3) changes in the Effective Load Carrying Capability ("ELCC") of solar, wind, and demand response, and a Loss of Load Expectation-derived planning margin.

In summary, Staff has determined that the load growth has already been incorporated into the peak load forecast filed in the Application and in the latest peak load forecast. Second, Staff believes the market availability from the Company's southern transmission pathways should be reduced. Finally, changes in ELCC and planning margins should be evaluated as part of the 2021 IRP and the subsequent capacity deficiency date filing. Each of these items and Staff's rationale will be discussed in further detail.

Furthermore, Staff recommends that a generic docket be opened to determine when the biannual deficiency date should be filed to reduce the issues due to the overlap in timing between IRP cycles (e.g. after the filing of an IRP, after the acknowledgement of an IRP, or at other times). This will allow the utilities, other parties, and Staff to weigh the pros and cons of different filing schedules.

Peak-Load Forecast

Because Staff is concerned that circumstances have changed since the proposed load forecast was developed, especially given COVID and its potential impacts on customer consumption patterns that could change the amount of load during system coincident peak, Staff recommends using the latest forecast in the L&R instead of the proposed load forecast.

The forecast used in the Application is the same forecast used in the Second Amended 2019 IRP. The Company states in Response to Staff's Production Request No. 11 that the proposed load forecast in the Application is not the latest load forecast, and the latest load forecast reflects the impacts of the COVID-19 pandemic. The pandemic-related adjustments in the latest load forecast include an increase in usage in the Residential sector, a decrease in usage of Industrial and Large Commercial customers for 2021 and 2022, a decrease in usage of remaining Commercial sector from 2021 through 2025, and load forecasts provided by Special Contract customers that reflect near-term demand and energy impacts attributable to recent changes in economic conditions. *See* Response to Staff's Production Request No. 11. Because the latest load forecast is slightly lower than the proposed load [redacted][3], using the latest load forecast while holding all other factors constant will push the first deficit date from August 2028 to July 2029. *See* Response to Staff's Production Request No. 25. Because Staff believes the latest load forecast is more current and accurate, Staff recommends that the Company recalculate the deficiency date using the Company's most recent load forecast.[4]

Resources in the L&R

Staff compared the resources included in the L&R in the recent capacity deficiency filings and IRP filings between Idaho's three regulated electric utilities and examined the rationale each electric utility used for determining what and how resources should be included in its L&R. Staff's objective in making these comparisons was to develop a common standard for what should be included in the L&R for each type of resource to guide Staff's review. In Order No. 29880, the Commission made it clear that consistency is important between the three regulated utilities:

> The Commission develops its PURPA contract standards and requirements in generic methodology, ratesetting[,] and complaint cases...It is reasonable for QFs to expect that the contract requirements of Idaho regulated electric utilities will be similar and that a QF will not be disadvantaged by choosing to sell to one utility rather than another.

Order No. 29880 at 10.

After identifying differences between the utilities, Staff used the justifications and rationales obtained through production requests, meetings with utilities, and Staff's evaluation of resources to document resources that are "available" and/or "existing" to include in the L&R.[5] A summary of these common standards for each resource type are included in Attachment A.

After developing common standards, Staff compared them to the resources the Company included in its L&R for establishing its proposed capacity deficiency date. Staff used the common standards as a default; if the Company's proposal deviated from the standard but the Company provided sufficient evidence, an exception could be made.

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[3] Both forecasts are 50th percentile loads, and the comparison is conducted at the annual level.

[4] Both the proposed load forecast and the latest load include the load growth referenced in the NOI. Changes in load forecast are not the main driver of the NOI. *See* Response to Staff's Production Request No. 22.

[5] The Commission expressed its expectation for focusing on "available" and/or "existing" resources when deciding whether transmission capacity should be included in the L&R in Order No. 33425.

Market Purchases

The Commission has stated that "import capability must be considered as part of its overall capacity balance. Avoided cost calculated without considering the Company's import capability would fail to recognize the entirety of the Company's available capacity resources." Order No. 33425 at 7. Import capability in this context does not center on the purchases of energy themselves, but on the ability to make purchases and as such must consider its ability to make short-term purchases using its transmission capacity. *Id.* Based on information supplied in response to Production Request No. 26, Staff believes it is appropriate to reduce the amount of Market Purchases <u>from southern pathways</u> by 310 MW and recommends only including 50 MW starting in 2021 in the L&R, effectively pulling in the deficit date.

The IRP is a long-term resource planning process used to ensure that the Company has identified cost-effective future resources outside of the lead-time required to acquire those resources so that the Company has sufficient infrastructure in place to maintain customer reliability. To maintain reliability, this infrastructure only includes generation and transmission that the Company can control on a long-term basis.

In contrast, operational planning involves planning how the Company will operate this infrastructure to optimize cost. In general, operational planning involves decisions regarding how much of which resources will be run and how much will be supplemented with market purchases sourced outside of the Company's system. Not locking in purchases on a long-term basis provides the Company with the flexibility to serve load while managing the risk of fluctuating market prices. In past IRPs, including the 2019 IRP, the Company has assumed that it can obtain market purchases up to the amount of transmission capacity within its own system because the market had sufficient liquidity.

However, one of the drivers necessitating the need for additional capacity through the NOI was a reduction in the amount of firm transmission capacity through "southern market hubs to North Valmy through the NV Energy system" and "on the PacifiCorp East transmission path through Utah to Idaho." Response to Staff's Production Request No. 26. Additionally, when asked whether the fundamentals driving the constraints in the transmission market were permanent or temporary, the Company responded that it expects third-party transmission availability to remain tight for the foreseeable future until incremental transmission is added to the system. Response to Staff Production Request No. 23. Staff's recommendation in this case is based on this new information. Staff further recommends the Company monitor its other transmission pathways in the 2021 IRP and future IRPs, since the market availability of firm transmission has tightened across the entire Western Interconnection. Staff believes it is appropriate to reduce the amount of Market Purchases <u>from southern pathways</u> by 310 MW and recommends only including 50 MW starting in 2021 in the L&R.

PURPA Contract Renewals

The Company assumes all PURPA contracts will renew, except for wind PURPA contracts. Based on the explanations provided by the Company, Staff believes this assumption is reasonable.

The common default position Staff developed for all three utilities is that all existing PURPA contracts are assumed to be renewed throughout the planning horizon, unless utilities have received information from QFs that contracts will not be renewed. Staff believes that almost all PURPA contracts will seek renewals and will be "available" to serve the Company's load for three reasons. First, utilities are mandated by PURPA to take energy produced by a facility determined to be a QF. 18 C.F.R. § 292.303. Second, since these facilities are already "existing" and currently in operation the roadblocks to establishing a renewal contract are minimal. Third, a total of 26 projects across three utilities were scheduled to expire in 2019 and 2020. Only two of them have expired without establishing a renewal. In every case, every facility continuing operation after its contract expired has established another contract with the same utility.

The Company assumes all PURPA contracts will renew except for wind PURPA contracts, given the high cost of repowering wind facilities, reductions and/or elimination of tax credits, current integration costs for wind, and the fact that none of the Company's wind QFs have requested or entered replacement energy sales agreements. Staff believes the rationale behind the assumption is reasonable.

Non-PURPA Contract Renewals

In the proposed L&R, the Company assumes all power purchase agreements ("PPA") will renew, except for wind PPAs. Through a teleconference meeting with Staff on July 9, 2021, the Company confirmed that the renewal of non-PUPRA PPAs was incorrect in the proposed

L&R and should be corrected. Staff supports this correction because project owners can sell power to any buyer through competitive bidding once capacity is no longer under contract. Therefore, Staff recommends that all PPAs expire in the L&R on their actual expiration dates.[6]

Contract Changes Since Development of the L&R

Since the preparation of the L&R in the Application, there have been several PURPA contract changes. *See* Response to Staff's Production Request No. 7. The following PURPA contracts in Table No. 1 have been terminated or expired without a replacement contract.

Table No. 1: Termination or Expiration of PURPA Contracts

Project	Resource Type	Nameplate Capacity (MW)
Bettencourt Dry Creek Biofactory	Biomass	2.25
Big Sky West Dairy Digester	Biomass	1.5
Double A Digester	Biomass	4.5
Rock Creek Dairy	Biomass	4
Kasel and Witherspoon	Hydro	0.9

Idaho Power has also added the following PURPA QFs in Table No. 2 since the development of the L&R.

Table No. 2: New PURPA Contracts

Project	Resource Type	Nameplate Capacity (MW)
Durkee Solar	Solar	3
Coleman Hydro	Hydro	0.8

On December 24, 2019, Jackpot Solar, a non-PURPA PPA, was approved by the Commission in Order No. 34515. Staff believes this PPA should be included in the L&R to accurately reflect resources in the Company's system.

[6] This adjustment alone may not have an impact on the first deficit date, because the PPAs' expiration dates are far beyond the proposed first deficit date of 2028. For example, Raft River PPA expires April 2033, and Neal Hot Springs PPA expires November 2037. *See* IPC-E-19-19, Second Amended 2019 IRP, p 43. However, this adjustment in synergy with other adjustments mentioned in the comments may lead to a first deficit date different than 2028.

Staff recommends that the Company update the L&R to reflect the PURPA and non-PURPA contracts mentioned above.

Company-owned Resources

Valmy Unit 2 is assumed to retire at the end of 2025 in the L&R, and Staff believes this is a reasonable assumption. Valmy Unit 2 started operation in 1985 with a 50-year useful life. However, in the Settlement of IPC-E-16-24, the parties agreed Idaho Power will negotiate with co-owner NV Energy — using prudent and commercially reasonable efforts — to accomplish a permanent end to coal-burning operations of Valmy Unit 1 by December 31, 2019, and of Valmy Unit 2 by December 31, 2025. Or, alternatively, the parties agreed that Idaho Power will use prudent and commercially reasonable efforts to end its participation in the operation of Valmy Unit 1 by December 31, 2019, and Valmy Unit 2 by December 31, 2025. The Settlement was approved in Order No. 33771. Therefore, Staff believes it is reasonable to reflect retirement of Valmy Unit 2 in the J&R based on the approved Settlement.

Non-owned Reserves

Non-owned reserves represent capacity sales through an Open Access Transmission Tariff to wholesale customers in a utility's Balancing Authority Area for which a utility is obligated to provide reserves. Staff believes existing non-owned reserve sales are included throughout the planning horizon, unless utilities are informed by the transmission customer of future changes. The Company confirmed that the non-owned reserves were included in its 15 percent planning margin in the proposed L&R. *See* Case No. IPC-E-19-19, Idaho Power's Reply Comments at 71. Staff believes it is reasonable. The 2021 IRP has used a Loss of Load Expectation-derived method to determine the planning margin, which may affect how non-owned reserves will be determined in the future. Staff will evaluate the method in the 2021 IRP review and the subsequent capacity deficiency date filing.

Capacity Contribution of Resources

It is critical that capacity values of various resources reflect their actual generation capability at system peak so that the first deficit date is calculated accurately. Staff identified that the capacity contribution of Valmy Unit 2 and Bridger units should be updated. In addition, the new method for determining the capacity contribution at peak for solar, wind, and demand response driving needs for resources identified in the NOI is a new method being developed in the 2021 IRP, not the 2019 IRP, and therefore Staff believes it should be evaluated as part of the 2021 IRP and the subsequent deficiency date filing.

The proposed L&R shows that the capacity value of Valmy Unit 2 is 136 MW. However, the correct capacity value should be 134 MW. *See* Response to Staff's Production Request No. 13. The proposed L&R also shows that the capacity value of Bridger is 703 MW. However, the correct capacity value should be 708 MW. *See* Response to Staff's Production Request No. 14.

The ELCC method used to determine the capacity contribution at system peak for solar, wind, and demand response—as well as the amount of planning margin used to adjust load—is a significant departure from past IRP practice. The new method has not been fully vetted in the 2021 IRP, and it is impractical to evaluate them outside of the context of a fully completed 2021 IRP. Until the 2021 IRP has been gone through its full cycle, Staff cannot with any certainty determine that the methods and the resulting impacts are valid.

STAFF RECOMMENDATIONS

Based on its analysis, Staff recommends the Company update the L&R and the resulting capacity deficiency date by incorporating the following changes:

- Utilize the most recent load forecast developed by the Company;
- Reduce the amount of Market Purchases <u>from southern pathways</u> by 310 MW and only include 50 MW starting in 2021;
- Allow non-PURPA PPAs to expire on their actual expiration dates;
- Reflect contract changes since the preparation of the L&R, which include PURPA contract updates identified in Response to Staff's Production Request No. 7 and approval of the Jackpot Solar contract; and
- Correct the capacity value of Valmy Unit 2 and Bridger.

If Staff's recommendations are authorized by the Commission, Staff proposes to update published rates on the Commission's website after the Company files an updated L&R and capacity deficiency date through a compliance filing. Furthermore, Staff recommends that a generic docket be opened to determine when the biannual deficiency date should be filed (*i.e.*, after the filing of an IRP, after the acknowledgement of an IRP, or at other times.). This will allow the utilities, other parties, and Staff to weigh the pros and cons of different filing schedules.

Respectfully submitted this 21st day of July 2021.

Matt Hunter
Deputy Attorney General

Technical Staff: Yao Yin
Kevin Keyt

i:umisc/comments/ipce21.9mhyyksk comments

Default Standards for Items in the Load and Resource Balance for Determining Capacity Deficiency		
Items	**Default Standards**	**Justification**
Company-Owned Resources	Existing resources reflect their authorized useful life, unless early retirements are authorized. Future resources and their useful life are included when authorized.	Any resource decision not authorized by the Commission is speculative.
Long-Term Generation Contracts	Existing PPAs expire at the end of the contract term. New contracts are only included if authorized.	PPAs from merchant generators can sell to any buyer through competitive bidding once capacity is no longer under contract.
PURPA Contracts	All existing PURPA contracts are assumed to be renewed throughout the planning horizon, unless utilities have received information from QFs that contracts will not be renewed.	Historic data shows that QFs seek renewals after contract expiration. Utilities are mandated to purchase power from qualifying facilities under PURPA. The roadblocks preventing an existing QF from establishing a renewal contract are minimal.
Interruptible Load Contracts	Interruptible load contracts are assumed to be renewed throughout the planning horizon, unless utilities have received information that such contracts will not be renewed.	Interruptible load contracts are with large existing customer and historical data shows they provide interruptible services as long they remain a load customer.
Planning Reserve Not Associated With Interruptible Load Contracts	Interruptible capacity is firm and do not require planning reserves.	Interruptible capacity contracts are firm.
Demand Response	Existing DR programs are included at current levels, but can reflect forecasted changes in the amount based on forecast levels of participation or known changes to program. Future new DR programs are not included.	Potential new DR programs are planned as alternatives to meet future capacity deficits and constrained by future load. Until programs are implemented, amount of capacity is speculative. Order No. 33159 allows current DR participation to be used as a reasonable estimation of participation into the future for existing programs.

Energy Efficiency	All cost-effective EE is included based on forecasted participation.	Utilities are expected to pursue all cost-effective EE. *See* Order Nos. 32426 and 33917. Amount of EE is not constrained by future load.
Private Generation: Net Metering	Net metering included at current levels but can reflect forecasted changes in the amount based on forecast levels of participation or known changes. Capacity is shown as an adjustment to load.	Capacity on the system is not constrained by load. Amount depends on customers that choose to make the investment.
Private Generation: Large Customers Generating Into Own Load	Private generation included at existing levels with future amounts based on known changes. Capacity is shown as an adjustment to load.	Private generation are also large customers and expected to self-generate as long as customer is included as load.
Front Office Transaction/ Market Purchases	Market purchases included in the Load and Resource Balance. Both existing transmission capacity and market availability should be considered.	Order No. 33425 states that a utility's import capability – its ability to make short-term purchases using its transmission capacity – should be included in the L&R.
Long-Term Wholesale Sales Obligations	Existing obligations expire at the end of contracts. No new, forecasted contracts are included.	Utilities plan resources to meet native load, while only selling into the wholesale market opportunistically.
Non-Owned Reserve Sales	Existing non-owned reserve sales are included throughout the planning horizon, unless utilities are informed by the transmission customer of future changes.	These types of reserve sales will continue to exist since utilities are required to balance the generation and load from these types of transmission customers (e.g. municipals and co-ops)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21ST DAY OF JULY 2021, SERVED THE FOREGOING **REDACTED COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-21-09, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

DONOVAN E WALKER
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: dwalker@idahopower.com
dockets@idahopower.com

CAMILLE CHRISTEN
ENERGY CONTRACTS
P.O. BOX 70
BOISE, ID 83707
E-MAIL: cchristen@idahopower.com
energycontracts@idahopower.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.corn

C TOM ARKOOSH
ARKOOSH LAW OFFICES
913 RIVER ST STE 450
BOISE ID 83702
E-MAIL: tom.arkoosh@arkoosh.com
erin.cecil@arkoosh.com

SECRETARY