Office of the Secretary
Service Date
December 23, 2025

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S ANNUAL COMPLIANCE FILING TO UPDATE THE LOAD AND GAS FORECAST IN THE INCREMENTAL COST INTEGRATED RESOURCE PLAN AVOIDED COST MODEL	)	**CASE NO. IPC-E-25-33** **ORDER NO. 36885**

On October 15, 2025, Idaho Power Company ("Company") filed its Annual Compliance Filing ("Filing") to update the load forecast, the natural gas forecast, and long-term contract changes used to determine avoided cost rates for Public Utilities Regulatory Policy Act of 1978 ("PURPA") qualifying facilities ("QFs") under the Company's Incremental Cost Integrated Resource Plan ("ICIRP") avoided cost method. In addition, the Company updated its Peak and Premium Peak Hours used to determine capacity payments for energy storage QFs. The Company requested an effective date of January 1, 2026, for these updates.

On November 4, 2025, the Commission issued a Notice of Filing and Notice of Modified Procedure, establishing deadlines for public comments and for the Company to reply. Commission Staff ("Staff") filed comments to which the Company replied.

Having reviewed the record, the Commission issues this Order approving the Company's annual update to its load forecast, contract changes, Peak Hours, and Premium Peak Hours as discussed herein. The Commission declines to adopt the Company's natural gas price forecast and directs the Company to take additional action described below.

BACKGROUND

Pursuant to PURPA and the Federal Energy Regulatory Commission's ("FERC") implementing regulations, this Commission has approved the IRP Method to calculate avoided cost rates for QFs that are above the resource-specific project eligibility cap. QFs that are below the applicable project eligibility cap may receive published avoided cost rates calculated using the surrogate avoided resource ("SAR Method"). *See* Order No. 32697 at 7-8. The avoided cost rate is the purchase price paid to QFs for the energy, or the energy and capacity, that the QF provides to the utility. 18 C.F.R. § 292.101(b)(6)(defining "avoided cost"). To ensure that avoided costs most accurately reflect the utility's marginal cost of energy or capacity, the Commission has directed utilities to "update fuel price forecasts and load forecasts annually–between IRP filings," and to update the Commission about its "long-term contract commitments because of [their] potential effect . . . on a utility's load and resource balance." Order No. 32697 at 22.

THE FILING

The Company currently forecasts an average annual load growth for the 20-year period following September 2024 forward that constitutes an increase from the average annual load growth forecast that the Commission approved in the Company's 2024 annual update. The Company states it developed its natural gas forecast using the most recent Henry Hub and Sumas Basis Annuals from S&P Platts Long-term Forecast, which was published in August 2025. The Company believes its proposed natural gas forecast is the most accurate and up-to-date reflection of the inputs to the Company's current avoided costs.

The Company states it has seven non-PURPA, long-term power purchase agreements with projects that are currently online, Elkhorn Valley Wind (101 megawatts ("MW")), Raft River Geothermal (13 MW), Neal Hot Springs Geothermal (22 MW), Jackpot Solar (120 MW), Black Mesa Solar (40 MW), Franklin Solar (100 MW), and Pleasant Valley Solar (200 MW). In addition to its agreements with non-PURPA projects, the Company has 129 contracts for PURPA QFs which have a total nameplate capacity of 1,128.58 MW. The Company further represents that it has one non-PURPA long-term battery services agreement with a battery energy storage system, the Kuna BESS (150 MW/600 MWh).

The Filing also updates the Peak and Premium Peak Hours used by the Company for the avoided capacity cost calculations available to energy storage QFs. The Company proposes transitioning to a Loss of Load Probability ("LOLP"), arguing that its more objective and capacity-based framework offers greater transparency and objectivity than the current method established in Order No. 34913. The Company conducted separate analyses using LOLP capacity-based framework exclusively and the existing method exclusively. The results of those analyses produced different Peak and Premium Peak Hours, which are set forth in the following table:

	Existing Methodology	Proposed Update
Summer Peak Hours	July: 1:00pm through 10:00pm August: 3:00pm to 8:00pm	June 15 to September 15: 3:00pm to 11:00pm
Summer Premium Peak Hours	July: 6:00pm through 10:00pm August: 6:00pm to 8:00pm	June 15 to September 15: 6:00pm to 11:00pm
Winter Peak Hours	No winter hours identified	November 15 to February 15: 5:00am to 10:00am and 4:00pm to 10:00pm
Winter Premium Peak Hours	No winter hours identified	November 15 to February 15: 6:00am to 9:00am and 5:00pm to 8:00 pm

STAFF COMMENTS

Staff reviewed the Company's load forecast, natural gas price forecast, contract updates, Peak and Premium Peak Hours, and revised the SAR model to incorporate the June 2027 capacity deficiency approved in Order No. 36855. This review resulted in Staff recommending approval of only the Company's load forecast. Instead of approving the Company's other proposals, Staff recommended adoption of its natural gas forecast, Peak and Premium Peak Hour proposal, updated SAR model, and the avoided cost rates for new and replacement contracts derived from Staff's SAR model, all effective January 1, 2026.

I. Load Forecast

Staff compared the load forecast proposed in this case with the one approved in last year's annual update (Case No. IPC-E-24-40). From 2026 through 2028, reduced load from special contract customers resulted in a lower proposed load forecast than last year. After 2028, inclusion of additional special contract customers resulted in the forecast exceeding last year's. Staff found this variation and the resulting proposed forecast reasonable. Accordingly, Staff recommended that the Commission approve the Company's proposed load forecast effective January 1, 2026.

II. Natural Gas Price Forecast

Staff compared the Company's proposed August 2025 S&P Platts long-term natural gas forecast to other available sources. Because ICIRP-based contracts are limited to two years, Staff focused its review on near-term prices and compared the Company's Henry Hub forecast with forecasts from cases AVU-E-25-13 and PAC-E-25-19, as well as NYMEX forward prices as of October 15, 2025. As the Company's near-term prices are materially higher than these benchmarks, Staff recommended rejection of the Company's gas price forecast.

Staff developed an alternative forecast using the methodology approved in Order Nos. 35344 and 36464. Under this approach, the first three years rely entirely on NYMEX forward prices published on October 15, the fourth year reflects an average of NYMEX and the Platts forecast, and the fifth year and beyond rely solely on the Platts forecast. Staff validated its forecast by comparing it to the same benchmark sources used previously and found it to be consistent, particularly in the near term. Accordingly, Staff recommended that the Commission approve its natural gas price forecast effective January 1, 2026.

III. Contract Changes

Staff reviewed the contract changes since last year's annual update case and believed them to be correct.

IV. Peak and Premium Peak Hours for Energy Storage QFs

Instead of relying on the approved methodology for determining Peak and Premium Peak Hours, the Company proposed using the LOLP method. The current methodology identifies Peak and Premium Peak Hours subjectively by comparing multiple data sources. In contrast, the LOLP methodology uses the Company's Reliability and Capacity Assessment Tool ("RCAT") model to calculate the probability of demand exceeding available generation each hour, with Peak and Premium Peak Hours defined by the highest LOLP values. This methodology is used to calculate avoided capacity costs in the export credit rate for on-site generation customers and to set Time-of-Use customer rates. *See* Case Nos. IPC-E-25-15 and IPC-E-23-11.

Despite considering this more sophisticated and objective approach reasonable, Staff noted that the Company did not exclude Sundays and holidays in its reporting. Accordingly, Staff recommended that the Commission reject the Company's Peak and Premium Peak Hours and adopt Staff's proposal reflected in the following Table No. 2 from Staff's comments:

Table No. 2: Staff Proposed Peak Hours and Premium Peak Hours

Summer Peak Hours	June 15 to September 15 ***excluding Sundays and holidays***: 3:00 pm to 11:00 pm
Summer Premium Peak Hours	June 15 to September 15 ***excluding Sundays and holidays***: 6:00 pm to 11:00 pm
Winter Peak Hours	November 15 to February 15 ***excluding Sundays and holidays***: 5:00 am to 10:00 am and 4:00 pm to 10:00 pm
Winter Premium Peak Hours	November 15 to February 15 ***excluding Sundays and holidays***: 6:00 am to 9:00 am and 5:00 pm to 8:00 pm

A. Applying Peak Hours and Premium Peak Hours in ICIRP Method

The Company provided an example of applying Peak and Premium Peak Hours in its ICIRP method, but Staff identified four issues with this method that need resolution. First, the example did not apply monthly Loss of Load Expectation weights to capacity payments. Second, it is unclear how rates would be calculated for half-month periods. Third, the benchmarking timeframe for Peak Hour Capacity Factor may need alignment with the approved Peak and

Premium Peak Hours or replacement with Effective Load Carrying Capability, as proposed for the Fossil Gulch wind project. Fourth, the example incorrectly includes QF generation on Sundays and holidays, which should be excluded. Staff recommended the Company meet with Staff before entering any new ICIRP-based energy storage QF contracts.

B. Applying Peak Hours and Premium Peak Hours in SAR Model

The existing SAR model treats all Peak Hours the same, and the Company proposed updating only the total annual Peak Hours. Staff recommended calculating separate avoided capacity costs for summer and winter to reflect seasonal risk, 83.3% in summer and 16.7% in winter. Under Staff's method, the Combined Cycle Combustion Turbine Annual Capacity Value is allocated by season and multiplied by the QF's generation during each season's Peak Hours to determine seasonal Capacity Payments.

V. Updated SAR Model and Published Rates

Staff updated the SAR model to reflect two key changes. First, Staff incorporated the recently approved June 2027 capacity deficiency for all QFs from Order No. 36855. Second, Staff calculated seasonal avoided capacity costs for energy storage QFs. Using its updated SAR model, Staff generated published avoided cost rates for all technology types. Attachment A to Staff's comments presents the rates for new contracts. Attachment B provides rates for replacement contracts. Staff recommended that the Commission approve the updated SAR model and the published avoided cost rates in Attachments A and B, with an effective date of January 1, 2026.

COMPANY REPLY

I. Load Forecast

The Company supported Staff's recommendation to approve the Company's proposed load forecast.

II. Natural Gas Forecast

The Company stated that its proposed natural gas forecast ensures that avoided costs are accurate and consistent with the IRP methodology. The proposed forecast aligns with the 2025 IRP and uses the August 2025 Platts long-term forecast, which the Commission previously approved as reasonable. *See* Order No. 35644.

The Company justified relying on Platts because it incorporates real-time market fundamentals (*e.g.*, supply, demand, pipelines, and storage) producing forecasts that reflect physical gas markets and align with the Company's trading operations. The Company contrasted this with the Intercontinental Exchange's NYMEX prices that reflect future contracts used for hedging, which do not match the Company's daily physical gas procurement or operational practices. Accordingly, the Company believes its Platts-based natural gas forecast provides the most accurate and current reflection of avoided costs.

III. Peak and Premium Peak Hours for Energy Storage QFs

The Company acknowledged its failure to clarify that its proposed Peak and Premium Peak Hours exclude Sundays and holidays. Because Sundays and holidays are so excluded, there is no substantive difference between the Company's proposal and Staff's recommendation on this issue. The Company also agreed that meeting with Staff to coordinate the application of Peak and Premium Peak Hours in the ICIRP model in future ICIRP-based energy storage QF contract negotiations would be beneficial.

IV. Updating SAR Model and Published Rates

The Company agreed with Staff's updates to the SAR model and found the published avoided cost rates reasonable and consistent with Commission orders, with one proposed modification to improve transparency and usability. Specifically, the Company recommended incorporating the summer and winter risk split into a different portion of the rate calculation model. According to the Company, this will enhance the model's usability and ensure that seasonal risk assumptions are transparent and easily verifiable. The Company included a Microsoft Excel spreadsheet reflecting this proposed change with its reply comments.

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-501through 503. The Commission is empowered to investigate rates, charges, rules, regulations, practices, and contracts of public utilities and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provision of the law, and to fix the same by order. *Idaho Code* §§ 61-502 and -503. Additionally, the Commission has authority under PURPA and FERC regulations to set avoided costs, to order electric utilities to enter fixed-term obligations for purchase of energy from QFs, and to implement FERC rules. The Commission may enter any final order consistent with its authority under Title 61, Idaho Code, and PURPA.

Under this authority, we have reviewed the record, including the Filing, Staff's comments, and the Company's reply. Although we find the proposed load growth forecast and all contract changes to be reasonable as filed, we cannot say the same for the Company's proposed natural gas price forecast. The near-term prices in the Company's proposed forecast substantially exceed those identified in Case Nos. AVU-E-25-13 and PAC-E-25-19, as well as NYMEX forward prices as of October 15, 2025. As contracts negotiated with ICIRP avoided cost methodology are typically two-year contracts, the accuracy and reliability of near-term price forecasting is critical.

Moreover, this is not the first time a significant discrepancy between the Company's natural gas forecast and those submitted by Idaho's two other large electric utilities has arisen. The Company's 2021 natural gas forecast was significantly lower than Avista's and Rocky Mountain Power's forecasts over the near-term, which is the critical timeframe for two-year PURPA contracts for QFs. Order No. 35294. The natural gas forecast submitted with the Company's last load and gas update predicted a significant price spike that no other forecast predicted. *See* Order No. 36434. To address this discrepancy, we directed the Company to file a three-year natural gas forecast using the latest NYMEX forwards prices to determine IRP avoided cost rates for contracts signed after January 1, 2025, until the Company's next natural gas price forecast annual update.

We direct the Company to use the alternative forecast developed by Staff. We acknowledge the Company's concern that NYMEX forward prices rely on hedging practices that differ from the Company's. However, considering the near-term consistency of Staff's forecast with other benchmark sources used previously, we find it reasonable to direct the Company to use this forecast. Accordingly, this forecast shall be used to determine avoided cost rates for contracts signed after January 1, 2026.

Regarding the calculation of Peak and Premium Peak Hours, we find it reasonable to direct the Company to use the LOLP method going forward. Not only is this method a more sophisticated and objective way to determine Peak and Premium Peak Hours, it is also consistent with the methods used to calculate avoided capacity costs in the export credit rate for on-site generation customers and to set Time-of-Use customer rates. Accordingly, we find the proposed Peak and Premium Peak Hours identified in Table No. 2 described above to be reasonable and approve them for use.

We find it reasonable to approve Staff's updated SAR model for use with the Company's proposed modification. Unlike the Company's proposal, Staff's SAR model reflects the recently approved capacity deficiency period of June 2027 and incorporates seasonal avoided capacity costs. Additionally, we find it reasonable to adopt the Company's proposed revision to Staff's SAR model as it will improve the transparency and functionality of the model. Accordingly, we further find it reasonable to approve the avoided cost rates based on Staff's model for new contracts contained in Attachment A to Staff's comments and the avoided cost rates for replacement contracts set forth in Attachment B to Staff's comments.

ORDER

IT IS HEREBY ORDERED that the Company's annual updates to its energy load forecast are reasonable and approved, effective as of January 1, 2026.

IT IS FURTHER ORDERED that the Company use the alternative natural gas forecast developed by Staff for contracts signed after January 1, 2026, until the effective date of the next natural gas price forecast annual update.

IT IS FURTHER ORDERED that Staff's proposed Peak and Premium Peak Hours used to calculate and pay capacity payments for energy storage QFs using ICIRP-based avoided cost rates are approved, as described above.

IT IS FURTHER ORDERED that the Company use the LOLP method described in this order to calculate Peak and Premium Peak Hours going forward.

IT IS FURTHER ORDERED that Staff's updated SAR model, with the Company's proposed modification, is approved along with the avoided cost rates for new contracts contained in Attachment A to Staff's comments and the avoided cost rates for replacement contracts set forth in Attachment B to Staff's comments that are based on that model.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order about any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

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DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 23rd day of December 2025.

EDWARD LODGE, PRESIDENT

JOHN R. HAMMOND JR., COMMISSIONER

DAYN HARDIE, COMMISSIONER

ATTEST:

Laura Calderon Robles
Commission Secretary

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