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|  | Identifying an Appropriate Contract Length for Storage Assets Under Current PURPA RatesReport for Idaho Public Utilities Commission StaffAugust 20201 JB Twitchell  |
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| Prepared for the U.S. Department of Energy under Contract DE-AC05-76RL01830 |

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# Introduction and Summary

This report details the results of analysis conducted at the Pacific Northwest National Laboratory (PNNL) on behalf of staff at that Idaho Public Utilities Commission (IPUC) to evaluate the role of energy storage within the current avoided cost rate schedules that Idaho Power has developed pursuant to the Public Utilities Regulatory Policy Act (PURPA). The specific objectives of the analysis were to determine whether energy storage assets would have a reasonable opportunity to recover their costs under current rate structures, and if so, what contract length would be necessary to enable them to do so.

The purpose of this report is to provide objective information to IPUC staff for consideration as staff develops recommendations to commissioners on current and future proceedings related to PURPA implementation. Nothing in this report is intended as a recommendation for what course staff or the commission should take, and should not be taken as such.

After extensive analysis considering different time horizons and multiple sizes and configuration of energy storage both as a standalone asset and coupled with solar photovoltaic (PV) generation, PNNL was unable to identify any scenario under which an energy storage asset would have a reasonable opportunity to recover its costs as a qualifying facility (QF) under current rate structures.

These findings come with an important caveat. This analysis was conducted using an avoided cost schedule with very little granularity, which prevented energy storage assets from providing any incremental value. An avoided cost structure such as this creates no incentive for an independent power producer who sells their power to Idaho Power under PURPA to shape or shift that energy production, which would be the primary function of energy storage in a PURPA contract. In this situation, adding storage to a generation resource adds costs, but does not add any value. In fact, because storage is a net energy loser – that is, it loses energy during the charge/discharge cycle and returns less energy to the grid than what it took in – passing a QF’s energy production through the storage without earning any additional revenue by doing so would actually reduce the project’s overall output and decrease its revenue.

This analysis suggests that if the objective of the IPUC is to create a viable participation model for energy storage assets under PURPA, more granular avoided costs and rates would be necessary.

The remainder of this report will provide additional detail about the analysis and conclusions. Section 2 describes the analytical approach and its findings, while Section 3 discusses the implications of those findings.

# Analytical Approach

The objective of this analysis was to identify under what circumstances it would be possible for an energy storage asset to recover its costs within Idaho Power’s current avoided cost schedule. To enable the analysis, IPUC staff provided PNNL with an avoided cost schedule that Idaho Power provided to staff during discovery in a current proceeding involving PURPA implementation.

Key characteristics of the avoided cost schedule are:

* Avoided costs are provided at monthly resolution through 2036
* There is a secondary breakdown on a daily basis between heavy load hours (7 a.m. to 10 p.m., Monday-Saturday excluding holidays) and light load hours (all other hours), with high load hours generally having slightly higher avoided costs
* Capacity payments do not begin until 2026, and are then levelized on an annual basis across all hours of the year
* There are different avoided costs for baseload resources and for solar resources.

While baseload resources generally receive slightly higher avoided cost rates through 2025, solar resources receive significantly higher rates from 2026-2036 because they are given higher avoided capacity costs than baseload resources. IPUC staff informed PNNL that the differential is due to solar generation aligning better with the utility’s summer peaks than baseload generation. Because a storage QF would be able to provide energy and capacity to the grid when needed, IPUC staff and PNNL agreed that the solar rates would be more appropriate to use for the analysis.

The Federal Energy Regulatory Commission (FERC) is responsible for establishing the regulations that govern PURPA implementation. Its rules on PURPA’s small power purchasing requirements state that a qualifying facility (QF) must be at least 75 percent powered by a PURPA-eligible fuel source (biomass, waste fuel, renewables, or geothermal).[[1]](#footnote-2) FERC has extended that principle to energy storage, ruling that storage can be a QF as long as it is at least 75 percent charged by a generator powered by a PURPA-eligible fuel source.[[2]](#footnote-3)

Based on that requirement, PNNL assumed that an energy storage QF would have to be connected to an eligible generator, and that based on development trends and economics, pairing the storage with PV generation made the most sense.

## Data Sources and Assumptions

Generation profiles for PV resources were obtained from the National Renewable Energy Laboratory (NREL) PVWatts calculator (<https://pvwatts.nrel.gov/pvwatts.php>), which is a web-based tool that allows users to input a location and configuration for a hypothetical PV generator. Using several years of solar irradiation data for the identified site and historical production data from nearby PV facilities, PVWatts estimates average annual production for the facility at hourly and monthly granularity. This analysis used the location “Boise, ID,” which identified the area shown in figure 1:



**Figure 1: Area used for PV production calculation in PVWatts.**

PNNL downloaded production estimates for hypothetical facilities of 20 megawatts (MW), 50 MW, and 80 MW of both fixed-tilt and single-axis tracking variants to test the economics of multiple project configurations.

For the energy storage component, PNNL assumed that based on commercially available technologies, a lithium-ion battery would be selected. Cost and performance data for the battery were obtained from a recent publication prepared by multiple national laboratories.[[3]](#footnote-4) Key performance assumptions for the lithium-ion battery are:

* Round-trip efficiency (how much energy the device puts out relative to what it took in): 86 percent, declining by 0.5 percentage points per year;
* Depth of discharge (the most amount of charge that can be used each cycle to maximize the battery’s useful life): 80 percent
* Cycle life (how many times the battery can charge and discharge): 3,500
* Energy to power ratio: 4 to 1 (i.e., a four-hour battery)

Table 1 summarizes the key cost assumptions for the PV and storage components, broken down by upfront capital cost and annual operations and maintenance (O&M) expenses:

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Component** | **Capital Cost** | **Annual Fixed O&M** | **Annual Variable O&M** | **Data Source** |
| PV | $1130/kW DC | $10.40/kW-yr | -- | “U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018”[[4]](#footnote-5) |
| Storage | $1446/kW | $9/kW-yr | $0.0003/kWh | “Energy Storage Technology and Cost Characterization Report” |

**Table 1: Key Cost Assumptions for PV and Storage Components**

With a cycle life of 3,500 cycles, a lithium-ion battery that is dispatched on a daily basis would have a useful life of about 10 years. Therefore, any analysis scenario that included a horizon of more than 10 years assumed a “capacity repurchase” of the battery after 10 years, by which the original cells would be replaced with new ones. The assumed cost of this battery capacity repurchase was 25 percent of the total energy storage system’s initial cost.

All analyses assumed a constant discount rate of 6 percent for all future project costs and revenues, which is roughly in line with recent historical commercial lending rates. For initial capital costs, the analysis assumed overnight capital, meaning that project financing considerations were not included.

## Analytical Details

Because energy storage must be charged by a PURPA-eligible source of generation, initial analyses approached the question from a hybrid perspective by attempting to identify a project with optimally configured PV and storage components that would potentially be cost effective under the provided avoided cost schedule for solar resources.

This approach consisted of downloading hourly generation data for hypothetical projects of various sizes from PVWatts, identifying daily generation cycles, and then identifying the size of a storage component that could cost-effectively capture as much of that generation as possible. But the flaw in this approach quickly became evident; absent some incremental value to be achieved by capturing and shifting generation, the storage component would only cause the project to lose money.

As previously noted, a new lithium-ion battery has a round-trip efficiency (RTE) of 86 percent. This means that for every megawatt-hour (MWh) of energy that the battery takes in, it only returns 0.86 MWh. These losses occur in the process of converting electricity from the grid’s alternating current to the battery’s direct current and then back again. They are also driven by the energy needed to maintain the battery’s operational systems and temperature controls.

So, from a developer’s perspective, it would only make sense to put energy into the battery if the value of energy when the battery is discharged will be at least 14 percent higher than the value of the energy that charged the battery. If not, the developer is better off not using the battery. Idaho Power’s avoided cost schedule used in this analysis compensates all generation occurring during heavy load hours equally, and does not penalize a resource for having variable output. Under that structure, there is no value in shifting energy to a different time, and so using the battery effectively constitutes a 14 percent tax on all the energy that goes through it – and that tax will rise by 0.5 percentage points each year as the battery’s RTE declines. Table 2 illustrates this point by comparing the revenue that a 20-MW, single-axis tracking PV facility would achieve under the current avoided cost schedule as a standalone facility and as a hybrid facility, in which all of its generation is passed through a battery:

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| --- |
| **Total Revenue for a 20-MW PV Facility Under Current Avoided Cost Schedule, 2021-2040** |
| Standalone | With Battery | Reduction |
| $39.6 Million | $33.1 million | 16.3 percent |

**Table 2: Revenue for a 20-MW PV Facility Under Current Avoided Costs, With and Without Battery Storage**

Table 2 is admittedly an extreme case; even under favorable rate design, it is unlikely that all of a generator’s output would be routed through a battery. But it illustrates the powerful disincentive that the current avoided cost schedule creates for energy storage.

Once this issue was identified, PNNL pivoted its approach to instead focus on a standalone energy storage device. The objective of this approach was to determine whether a storage asset could be cost-effective assuming no-cost charging, and if so, how much revenue would be generated to acquire assets to charge the device, either by developing them with the storage project or contracting for charging energy from a PURPA-eligible resource. This approach was also unsuccessful, as it determined that the benefit/cost ratio for a standalone storage device would be 0.25 over 10 years and 0.43 over 20 years – *before* any charging expenses are included. Because the costs and output of a battery are all linear, those ratios are constant across all battery sizes (assuming a constant energy to power ratio of 4:1).

Finally, PNNL approached the issue through the lens of a standalone PV facility. The question was the inverse of the previous approach; could a PV facility generate enough revenue to add a storage component? While the short answer was no, the results of the analysis suggest that, under more detailed avoided cost structures, it may be possible. The economics of a single-axis tracking PV facility are generally more favorable under the current avoided cost structure, resulting in a benefit/cost ratio of .85 for a 20-MW facility and increasing to .88 for a facility of 80 MW, which is the maximum size for a QF. With enough of an incentive to shift production to more valuable periods, it is conceivable that storage could become a cost-effective QF when coupled with single-axis tracking PV.

# Implications

Due to its RTE limitations, energy storage can be viewed as one of two things: a tax or an investment. In either case, some of the energy used to charge the device will be lost when it is discharged. Under the tax paradigm, there is no opportunity to recover the value of that energy, and it is lost as well. But under the investment paradigm, the value of that energy can be recovered – with interest – by providing more valuable grid services with the energy that remains.

Levelized avoided cost structures that set static prices for energy and capacity have historically been the vehicle by which utilities comply with their small power purchase obligations under PURPA. But as the changing resource mix causes grid needs to evolve, this structure is increasingly unable to induce and compensate desirable behavior from interconnected resources.

Idaho Power’s avoided cost schedules are a prime example of this. When capacity payments begin in 2026, they are levelized throughout the year. Effectively, the payment structure states that a unit of capacity on a January morning has the same value as a unit of capacity on an April night or a July afternoon. This is clearly not the case, as Idaho Power acknowledges in its 2019 Amended IRP when it points to its own peak demand happening in June or July and regional analyses suggesting that the highest loss of load probability for the Pacific Northwest as a whole occurs in winter months.[[5]](#footnote-6) The value of capacity varies significantly throughout the year as the needs of the grid change, but when utilities pay for it on a levelized basis, they eliminate any incentive for QFs to help them meet those needs.

Idaho Power’s avoided capacity payments – when offered – also compensate solar resources at a rate that is three times greater than the rate paid to baseload resources. A kW of capacity during a time of need has the same value to the grid regardless of its source, but the current avoided cost structure does not treat them the same. In fact, the opposite could be argued – that a kW of capacity from a dispatchable/predictable resource may be more valuable than a kW of capacity from a non-dispatchable/variable resource. Under the legacy PURPA approach, which varies rates based on a resource’s characteristics, Idaho Power’s avoided cost schedule has created perverse incentives.

Energy storage creates the mechanism by which utilities and regulators can move from a resource-centric approach to PURPA toward a grid-centric approach that creates resource-agnostic signals for QFs to shape their production according to grid needs. By creating clear signals about when energy and capacity are most valuable on the grid, avoided cost schedules can establish an incentive for QFs to cost-effectively deploy storage in a manner that will benefit the grid and all of its customers.

An example of this type of rate structure is found in Duke Energy’s avoided cost tariffs in North Carolina. These cutting-edge tariffs increase avoided cost granularity in multiple dimensions:

* **Volatility.** Resources are compensated based on how well they manage the volatility of their production across rolling 10-minute windows on a monthly basis. Resources that meet established thresholds are compensated at a high rate than those that don’t.
* **Seasonality.** Avoided costs vary across three seasons (summer, winter, shoulder).
* **Hourly.** Avoided costs vary by time of day, with three tiers during summer months, four tiers during winter months, and two tiers during shoulder months.
* **Point of interconnection.** Avoided costs vary by whether a resource is connected at distribution voltage or at transmission voltage, recognizing its contributions to reducing line losses based on where it is connected.
* **Rate structure.** QFs can elect to receive an as-available (real-time) rate or a long-term (contracted) rate.
* **Resource type.** Methane digesters and hydropower facilities have separate rate structures based on their characteristics and state policies.

The end result is that where Idaho Power has 48 different rates over the course of a year (heavy load/light load hours that vary by month for two different types of resource), Duke Energy has 108 different rates over the course of the year, which create clear and detailed signals for how QFs should be designed and operated to maximize their value to the grid.

IPUC staff’s objective of creating a viable model for energy storage assets to participate in PURPA cannot be achieved under Idaho Power’s current avoided cost structure. This is not meant as a criticism of Idaho Power nor of the IPUC; as previously mentioned, this type of avoided cost structure has been standard practice in the electric industry since PURPA was passed in 1978. But the IPUC is working under a legal requirement to develop avoided cost rates that account for the unique characteristics of energy storage, in a state that has been at times inundated with new PURPA projects. As such, the IPUC is uniquely situated to play a leading role in designing avoided costs that more directly link the compensation of QFs to the value that they provide to the grid and to customers, with energy storage serving as the conduit to shape their generation and maximize its value.

PNNL appreciates the opportunity to contribute to this challenging and important work, as it provides a window into the challenges that other states will likely face in the near future and insight into how those challenges can be resolved. The lab looks forward to ongoing collaboration as staff continues to investigate these issues.

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1. 18 CFR § 292.204(b)(1)(i). [↑](#footnote-ref-2)
2. See *Luz Finance and Development Corp.,* 51 FERC 61,078. [↑](#footnote-ref-3)
3. Mongird K, V Viswanathan, P Balducci, J Alam, V Fotedar, V Koritarov, B Hadjerioua. 2019. “Energy Storage Technology and Cost Characterization Report.” Richland, WA: Pacific Northwest National Laboratory. <http://energystorage.pnnl.gov/pdf/PNNL-28866.pdf>. [↑](#footnote-ref-4)
4. Fu R, D Feldman, R Margolis. 2018. “U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018.” Golden, CO: National Renewable Energy Laboratory. <https://www.nrel.gov/docs/fy19osti/72399.pdf>. [↑](#footnote-ref-5)
5. Idaho Power Amended 2019 IRP at pgs. 120-121 [↑](#footnote-ref-6)