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March 12, 2025

VIA E-MAIL TO

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket No. UM 2317 – In the Matter of Idaho Power Company, Application for Approval of 2028 All-Source Request for Proposals to Meet 2028 Capacity Resource Need.

Attention Filing Center:

Attached for filing in the above-referenced docket, please find a redacted and confidential version of the London Economics International, LLC, Supplemental to Closing Report for the 2028 All-Source Request for Proposals for Peak Capacity and Energy Resources. The confidential version of this report will be distributed via an encrypted and password protected folder to parties who have signed General Protective Order No. 23-132.

Please contact this office with any questions.

Sincerely,

Cole Albee

Cole Albee
Paralegal
McDowell Rackner Gibson PC

REDACTED

Supplemental to Closing Report
2028 All Source Request for Proposals for Peak Capacity and Energy Resources

Confidential and Privileged

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January 31, 2025

Table of contents

Table of figures

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List of acronyms

AEO	Annual Energy Outlook
AS	All Source
BESS	Battery Energy Storage System
BSA	Battery Service Agreement
BTA	Build-Transfer Agreement
COD	Commercial Online Date
EIA	US Energy Information Administration
EPC	Engineering, Procurement, and Construction
ERIS	Energy Resource Interconnection Service
FOM	Fixed Operations and Maintenance
FOR	Forced Outage Rate
GIA	Generator Interconnection Agreement
GSU	Generator Set Up
H2	Hydrogen
IE	Independent Evaluator
IPC	Idaho Power Company
IRA	Inflation Reduction Act
ISL	Initial Shortlist
ITC	Investment Tax Credit
LEI	London Economics International LLC
LGIA	Large Generator Interconnection Agreement
LTSA	Long-Term Service Agreement
NREL	National Renewable Energy Laboratory
NRIS	Network Resource Interconnection Service
NTP	Notice to Proceed
O&M	Operations and Maintenance
OPUC	Oregon Public Utility Commission
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic
RFP	Request for Proposals
VOM	Variable O&M
WRAP	Western Resource Adequacy Program

1 Executive Summary

London Economics International ("LEI"), the Independent Evaluator for Idaho Power Company's 2028 All Source ("AS") Request for Proposals ("RFP") for Peak Capacity and Energy Resources, has prepared the present report in supplement to the 2028 AS RFP Closing Report, filed on January 10, 2025. This report responds to two conditions.

First, LEI prepared its review of the unique risks and advantages associated with utility-owned bids selected for the 2028 AS RFP Final Shortlist that are not benchmark bids. The IE's Closing Report filed on January 10, 2025 covered the unique risks and advantages associated with benchmark bids, only, and did not provide an analysis of projects under a build-transfer agreement ("BTA") structure. As per comments filed by Oregon Public Utility Commission ("OPUC") Staff on January 24, 2025, "The IE will cover unique risks of utility-owned non-benchmark resources in a supplemental report…."[1]

In this supplemental filing, we present our findings on the unique risks and advantages of the three utility-owned BTA bids selected for the Final Shortlist:

- [redacted] project, a 110 MW natural gas-fired facility with hydrogen ("H2") blending capability;
- [redacted] project, a 330 MW single-axis tracking solar photovoltaic ("PV") project; and
- [redacted] 150 MW [redacted] **Energy Storage 2** [redacted] project.

These bids were evaluated following the criteria prescribed by Oregon Administrative Rules (OAR 860-089-0450). The same criteria were considered in the IE's review of the benchmark bids in its January 10 Closing Report. This condition is covered in Section 2 of this document.

Second, LEI conducted a review of the sensitivity analysis performed by Idaho Power Company ("IPC" or the "Company") on assumptions pertaining to the resale value (on the secondary market) of Investment Tax Credits ("ITC") and Production Tax Credits ("PTC"). The analysis was performed to measure the impact of IPC's assumptions on the scoring and relative competitiveness of assets-purchase bids vis-à-vis bids with other contract structures (power purchase agreements ("PPA") and battery storage agreements ("BSA")). The sensitivity analysis was prepared in response to Scoring and Modeling Methodology Condition 4, or "SMM Condition 4," provided in the July 29, 2024 OPUC Staff Report.[2] LEI's review of the analysis is covered in Section 3 of this document.

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[1] OPUC. *Staff Comments*. Docket No. UM 2317. January 24, 2025. p. 20.

[2] OPUC. *Staff Report*. Docket No. UM 2317. July 29, 2024.

2 Unique risks and advantages of 2028 utility-owned, non-benchmark bids

Per Oregon's Competitive Bidding Guidelines, the IE is to assess whether utility-owned bids pose any potential unique risks to IPC's ratepayers. These guidelines apply not only to utility-sponsored bids (i.e., benchmark bids), but also to any bids that involve an asset transfer to the utility (i.e., asset purchase or BTA). These unique risks are discussed in the following subsections in the context of three proposed non-benchmark BTA bids, all included in the Final Short List: the [redacted] project by [redacted] ("[redacted]"), the [redacted] project by [redacted], and the [redacted] project by [redacted] ("[redacted]").

2.1 Unique risks and advantages

Per OAR 860-089-0450, the IE is required to "evaluate the unique risks and advantages associated with any company-owned resources." More specifically, the IE must evaluate the following items:

a. **construction cost overrun**s (considering contractual guarantees, cost and prudence of guarantees, remaining exposure to ratepayers for cost overruns, and potential benefits of cost under-runs);

b. reasonableness of **forced outage rates** ("FOR");

c. reasonableness of any proposal or absence of a **proposal to offer electric company-owned** or benchmark resource elements (e.g., site, transmission rights, or fuel arrangements) to third-party bidders as part of the draft and final RFP;

d. end **effect values**;

e. **environmental emissions** costs;

f. reasonableness of **operation and maintenance** costs;

g. adequacy of **capital additions** costs;

h. reasonableness of performance assumptions for **output, heat rate, and power curve**; and

i. specificity of **construction schedules** or **risk of construction delays**.

As discussed in the Closing Report submitted on January 10, 2025,[3] IPC does not intend to offer access to three of its benchmark resources to third-party bidders; access to the fourth benchmark resource would be conditional. LEI finds this to be reasonable based on IPC's explanation. IPC states in the RFP that the [redacted] Wind, [redacted] Wind & battery energy storage system ("BESS"), and [redacted] projects are located on "property that Idaho Power has no current rights

[3] London Economics International LLC. *Closing Report; 2028 All Source Request for Proposals for Peak Capacity and Energy Resources*. January 10, 2025. p. 18.

directly and is relying on partnership site control and thus cannot offer site access as Idaho Power has no authority to do so."[4] [redacted] BESS is located on "Idaho Power owned property and [is] intended to be incorporated into existing substations, thus these sites are only available to third-[party] bidders proposing a Build Transfer Agreement (Asset Purchase) based on access control and ongoing utility operation."[5]

In the subsequent sections, LEI analyzes the remaining distinctive risks and benefits associated with the three BTA projects.

2.1.1 [redacted]

The [redacted] project by [redacted] ([redacted]) consists of (1) a solar photovoltaic and BESS project and (2) a project consisting of reciprocating engines and turbines plus BESS unit. With respect to the former, the solar component is being offered via a PPA while the BESS component is being offered under a BSA. With respect to the latter, the BESS component is being offered under a BSA while the reciprocating engines and turbines are being offered under a BTA. This assessment focuses on the BTA element of [redacted] proposal.

[redacted] specifically proposes power generation equipment supplied by Peterson CAT and Solar Turbines (a wholly owned subsidiary of Caterpillar Inc.) and consisting of two "unique and complimentary systems" that run on natural gas with hydrogen-blending capabilities: twenty four (24) 2.5 MW reciprocating engines that can achieve up to 25% of hydrogen blending, and three skid mounted turbines that can achieve up to 30% of hydrogen blending. The project has a design life of 30 years and a proposed 110 MW of total capacity, broken down into 60 MW from the reciprocating engines and 50 MW from the turbines. The facility is meant to provide fast ramping energy with a low heat rate, contribute to credits under the Western Resource Adequacy Program ("WRAP"), and does not assume any energy degradation.

The IE is concerned with several aspects of this project. First is the potential for cost overruns, the high variable costs associated with operating the proposed facility, and possible costs associated with the facility's emissions. The IE is also concerned with the lack of clarity surrounding the proposed project's access to natural gas (let alone the hydrogen that would be used for blending), and the timing associated with securing this access. FOR, FOM, and performance values proposed by the project developer deviate from what seem to be more standard in the industry.

Construction cost overruns

According to the bid narrative, the asset purchase was proposed at a price of [redacted]. This amount includes a network upgrade cost of $[redacted] but excludes the costs of constructing the building in which the unit would need to be located (thus, the final price may be higher than estimated). The price was later updated to $[redacted], inclusive of a network upgrade cost of

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[4] Idaho Power Company. *2028 All Source Request for Proposals for Peak Capacity and Energy Resources*. Updated November 25, 2024. Exhibit N.

[5] Ibid.

$[redacted]. The bid narrative also notes that the price may be subject to change based on how IPC and [redacted] decide to optimize the size and configuration of the reciprocating engines and turbines—as such, the submitted bid price may not be indicative of the final purchase price. The project is ineligible for the ITC and PTC.

With respect to the development of the project, it is unclear to LEI whether [redacted] has relevant experience with sourcing hydrogen fuel to enable blending. The costs associated with identifying and securing a reliable source of hydrogen should be a factor in the overall development cost—although we also reckon that the power plant could be operated only with natural gas as the primary fuel.

With respect to natural gas supply, the bid narrative notes that the project will be located closest to the Williams Northwest Pipe, an interstate natural gas pipeline that [redacted] states has "ample supply."[6] The project would have access to Williams Northwest through the Intermountain Gas Mains, which would be located parallel to the project and would be "a straightforward connection."[7] Inability of IPC to source natural gas from these pipelines would likely result in additional costs for the project. It is also unclear to LEI whether the connection between the [redacted] project and the Intermountain Gas Mains has been accounted for in the bid price.

Reasonableness of FOR

According to the bid narrative, the reciprocating engines will have a FOR of 3% while the turbines will have a FOR of 2%; IPC's updated financial model lists a FOR of 1.5% for the project, perhaps the result of updated information from the developer.

The FOR values are lower than what has been observed in the industry, where the sources reviewed by LEI indicate a FOR ranging between 6.7% and 11.7% for natural gas units.[8,9]

Reciprocating engines have "have good part load efficiencies, and generally have high reliabilities,"[10] and thus are likely to have a low FOR. A lower FOR is beneficial to ratepayers as

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[6] [redacted]. *2028 All-Source RFP Idaho Power –* [redacted] *Proposal Letter*. September 16, 2024. p. 9.

[7] Ibid.

[8] California Energy Commission. *Staff report: Midterm reliability analysis*. September 2021; North American Electric Reliability Corporation. *2024 State of Reliability*. June 2024. p. 59; NREL. *Impact of Detailed Parameter Modeling of Open-Cycle Gas Turbines on Production Cost Simulation*. December 2023. p. 3.

[9] An EIA report using data provided by Sargent & Lundy assumes internal combustion engine costs for a natural gas-fired RICE asset. Source: EIA. *Capital cost and performance characteristic estimates for utility scale electric power generating technologies*. February 2020. While a more updated version of this report is available (dated January 2024), this updated iteration of the report does not provide any discussion on reciprocating engines.

[10] US EPA CHP partnership. *Catalog of CHP technologies. Section 2. Technology characterization – Reciprocating internal combustion engines*. March 2015. p. 2-2.

it means that it is operating and available most of the time, which helps ensure a reliable and stable grid.

End effect values

LEI does not believe that [redacted] provided any end-of-life plan for the proposed [redacted] project or included decommissioning costs. According to Resource for the Future, based on 2016 data, the mean decommissioning cost estimate for gas-fired plants is $15,000/MW;[11] inflated to 2024 dollars, this would be over $19,500/MW.[12] Accordingly, [redacted] would incur a cost of approximately $2,145,000 (in 2024 dollars). The largest portion of decommissioning costs is typically associated with dismantling turbines as well as cleaning and removing fuel storage equipment such as tanks and transportation lines.[13] It is worth noting that decommissioning costs could be defrayed or offset by the salvage value of scrap steel, which could reach above $20 million for large plants.[14]

Environmental emissions costs

The project's estimated CO2 emissions rate is 1,010 lbs/MMBtu for the reciprocating engines and 1,270 lbs/MMBtu for the turbine component. In addition to CO2, the project is also anticipated to have some NOX and SOX emissions.

It is possible that [redacted] could at some point in time be subject to environmental emissions costs. If this was the case, then a ballpark calculation indicates that the applicable cost for [redacted]—assuming it runs 100% on natural gas and has to pay for 100% of its emissions—could be as high as $53.9 million per year. This is based on a calculation consisting of the following steps to estimate total carbon emissions per year (obtained in lbs, then converted into metric tons,[15] for a total of 414,520 metric tons/year): carbon content of natural gas of 116.98 lbs/MMBtu x heat rate of 8.315 MMBtu/MWh x 110 MW x 8,760 hours x 97.5% capacity factor. LEI then multiplied the calculated carbon emissions figure by Oregon's Community Climate Investment credit contribution of $130 (effective starting March 1, 2027).[16,17]

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[11] Resource for the Future. *Decommissioning US power plants: Decisions, costs, and key issues*. October 2017.

[12] This is based on an inflation calculation made available by the US Department of Labor: https://www.dol.gov/general/topic/statistics/inflation.

[13] Ibid.

[14] Ibid.

[15] According to the EIA, one metric ton is equal to 2,204.6 pounds. See the EIA's Glossary.

[16] Oregon Administrative Rules 340-273-0810, accessed via the Oregon Secretary of State website.

[17] If we instead used California's 2025 Tier 1 carbon price of $60.47/metric ton, then the environmental emission cost could be about $25.1 million. Sources referenced for this calculation: California Air Resources Board. *Cost*

Reasonableness of FOM costs

[redacted] estimates fixed operations and maintenance ("FOM") costs to be $[redacted]/kW-year, which is significantly higher than other publicly available estimates. For instance, the National Renewable Energy Laboratory ("NREL") estimates FOM costs range from $26.1/kW-year to $40.00/kW-year;[18] the EIA's FOM for an internal combustion engine is $43.95/kW-year.[19]

Moreover, the project also has variable operations and maintenance ("O&M") costs of $[redacted]/MWh for the reciprocating engines component and $[redacted]/MWh for the turbine component—both also vary significantly from the equivalent estimates for gas units. According to NREL, variable costs are assumed to range from $2.16/MWh to $2.94/MWh for the most efficient base load natural gas-fired generation.[20] These costs are quite substantial, which suggests that further refinements might be made.

[redacted] also notes in its bid entry form that O&M escalation (without specifying whether specific to FOM or variable O&M ("VOM")) may increase after year five; in addition, "overhaul" seems to be required for the solar turbines after 30,000 hours.

Furthermore, IPC was concerned about the project's fuel supply arrangements, which may affect supply flexibility and cost stability. Subsequently, IPC sent a data request[21] to [redacted] and hired a consultant to conduct due diligence on the responses.

Adequacy of additional capital costs

[redacted] bid does not seem to mention any contingency allowance or cost to interconnect with the relevant natural gas infrastructure. It also excludes the cost associated with the building that is required to house the facility. As such, the risk of additional capital costs seems rather high.

Containment Information. Accessed January 23, 2025; EIA. *Carbon Dioxide Emissions Coefficients*. September 18, 2024.

[18] NREL. *Annual technology baseline. Fossil energy technologies*. 2024.

[19] The EIA FOM figure—provided by Sargent & Lundy–is based on a natural gas internal combustion engine of 21 MW net nominal capacity. See "Case 4," where Sargent & Lundy writes: "This case is a reciprocating internal combustion engine (RICE) power plant based on four large-scale natural-gas-fired engines." Sargent & Lundy assumes a configuration of an internal combustion engine for this reciprocating engine example. The report—issued in December 2019—assumes a FOM cost of $35.16/kW-year, which LEI then escalated to 2024 prices using an inflation calculator made available by the US Department of Labor. Source: EIA. Capital cost and performance characteristic estimates for utility scale electric power generating technologies. February 2020. While a more updated version of this report is available (dated January 2024), this updated iteration of the report does not provide any discussion on reciprocating engines.

[20] NREL. *Annual technology baseline. Fossil energy technologies*. 2024.

[21] Data request was sent via email from IPC to [redacted] on November 19, 2024, and [redacted] replied on November 26, 2024.

Reasonableness of performance assumptions for output, heat rate,[22] and power curve

The project has a capacity factor of 97% for the reciprocating engines component and 98% for the turbine component, which is at the high end of what has been reported by other studies. For example, NREL reports that the capacity factor for gas plants ranges from 12% to 87%.[23] Such high capacity factor indicates that the project would be among the first resources to be dispatched at all times. From a purely economic perspective, such expectations would be at odds with the relatively high predicted VOM costs, which would make the project expensive to operate.

The project reports on its anticipated heat rates for both the summer and winter periods. The proposed average heat rate (maximum dependable) for the reciprocating engines is 8,131 Btu/kWh for both summer and winter base capacity; for the turbines, the average heat rate (maximum dependable) is 9,709 Btu/kWh for summer base capacity and 10,005 Btu/kWh for winter base capacity. The average heat rate for the reciprocating engines falls within the range of heat rates reported in other studies; the average heat rates for the turbines are at the high end of this range. Specifically, NREL concludes the heat rate ranges from 6,068 Btu/kWh to 9,717 Btu/kWh.[24]

Specificity of construction schedule or risk of construction delays

The project's proposed commercial online date ("COD") is December 1, 2027. The bid narrative notes that, if IPC selects the gas-H2 option, only, then [redacted] will try to locate the project closer to the point of interconnection and master substation (going through local Authorities Having Jurisdiction) and develop an accelerated project timeline. The bid narrative does not go into detail about this potentially accelerated timeline. Even if the project's equipment could be delivered by the proposed COD, it remains unclear whether the required natural gas pipeline infrastructure would be ready in time—for either COD or the "accelerated" date.

[redacted] proposes six *payment* milestones, only three of which correspond with project *construction* milestones. These three construction milestones are: start of engineering design, start of construction, and expected COD. Agreeing to milestone payments that are not tied to any project development progress may result in modifications to the construction timeline, or ratepayers covering project costs that may not reflect actual development progress. Moreover, [redacted]

There are several other areas of uncertainty. For instance, while the Large Generator Interconnection Agreement ("LGIA") for the project is complete, it is listed as "in suspension"

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[22] Heat rate is irrelevant to BESS units because power is generated without fuel combustion, hence it is not discussed in this section.

[23] NREL. [Annual technology baseline. ATB electricity data overview](). 2020.

[24] NREL. [Annual technology baseline. Fossil energy technologies](). 2024.

without any explanation thereto. With respect to interconnection, while the project was studied for Energy Resource Interconnection Service ("ERIS"), the bid narrative notes that GIA negotiations are to begin "shortly" without clarifying the timeline.

Comments on contract risk

In terms of contract redlines, the bidder has not yet provided proposed modifications to commercial terms that are relevant to the BTA portion of the project, making it difficult to ascertain at this time other risk-prone commercial terms. In footnotes, [redacted] writes that commercial terms are yet to be modified to reflect a thermal project. Assuming the submitted redlines would apply to the thermal portion of the project, then the bidder and IPC will need to come to an agreement on items such as force majeure (for example, whether supply chain issues count as force majeure, which may have implications on price and construction), flexibility around COD, and performance guarantees. The IE is particularly concerned by this project, which presents major risks in terms of feasibility and costs overruns, which negatively impact ratepayers.

2.1.2 [redacted] – [redacted]

[redacted] single-axis tracking solar PV project is a 330 MW solar project that was selected for the Final Shortlist. While [redacted] has identified some cost savings in the draft BTA and technical specifications, there are still additional risks associated with potential construction cost overruns, as elaborated in subsequent sections. The [redacted] project's proposed FOR, FOM, and capacity factor appear to be reasonable and in line with industry standards.

Construction cost overruns

[redacted] proposes an asset purchase price of $[redacted].[25] This price reflects [redacted] modifications to IPC's draft contract terms and technical specifications, which [redacted] claims would have resulted in a higher total project cost than the cost it is offering with [redacted]. [redacted] proposed cost savings result from the following adjustments to the draft contract terms and technical specifications:

- ***use of aluminum cables:*** IPC's technical specifications for solar PV require the developer to only use copper cables;[26] however, [redacted] notes that the industry typically uses

[25] [redacted] notes in its bid narrative that its asset price is [redacted] lower than the so-called "IPC Terms" asset price. While the $[redacted] in "IPC Terms" costs is not fully clear to LEI, we understand that this figure is based on [redacted] estimation of costs based on its interpretation of IPC's draft contract terms and technical specifications provided in Exhibits F and H. "IPC Terms" costs do not appear to be costs proposed by IPC. [redacted] writes in its bid narrative: "The 'IPC Terms' asset purchase price is based on IPC contract terms and technical specifications in Exhibits F and H of the Idaho Power 2028 All Source RFP. The '[redacted] Redlines' asset purchase price option reflects [redacted] proposed redlines to these Exhibits." Source: [redacted] – *330 MWac Solar Generation Project*. September 13, 2024. p. 24.

[26] [redacted]. *Exhibit H. Solar Technical Specifications*. Section 4.1.12. 2024.

aluminum cables given that the cost of using copper cables outweighs the benefits.[27] If the change is accepted, this would result in a cost saving of $[redacted].

- ***use of a cable plow:*** IPC's technical specifications do not allow direct buried cables for installation and therefore the developer needs to use a cable tray system.[28] [redacted] notes that "the site lends itself well for installing cables using a cable plow,"[29] which could significantly reduce costs and improve the construction timeline compared to using a cable tray system. If the change is accepted, this would result in a cost saving of $[redacted].

- ***improvement of workflow and administrative efficiencies:*** [redacted] notes that certain design, construction, and administrative burdens in IPC's technical specifications could be avoided by using more efficient practices and without sacrificing quality, which would result in a cost saving of $[redacted].[30]

- ***changes in BTA terms***: [redacted] proposes adjustment to several contract terms that would allow for the procurement of equipment further down the development timeline, removing redundant contractor security requirements. Adjustments were made to the following terms: early termination (allowing for termination—under certain conditions—any time prior to the closing date[31]), developer and contractor credit support (term was removed, since the developer and contractor are affiliates of [redacted], hence no support is needed[32]), pre-substantial completion (introduced a financial incentive for energy generated before the substantial completion date[33]), and warranty period date (to commence from the substantial completion date rather than final completion date[34,35]). These adjustments result in a cost saving of $[redacted] for IPC.

IPC has reviewed and approved the redlines.[36] Therefore, the final asset purchase price is $[redacted]. Note that while the proposed asset purchase price includes the cost of a side substation,

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[27] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 25.

[28] [redacted]. *Exhibit H. Solar Technical Specifications.* Section 4.2.4.2. 2024.

[29] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 25.

[30] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 25 & 62.

[31] [redacted]. *Exhibit F. Build Transfer Agreement*. Section 2.11 a(x). 2024.

[32] [redacted]. *Exhibit F. Build Transfer Agreement*. Section 6.4. 2024.

[33] [redacted]. *Exhibit F. Build Transfer Agreement*. Section 12.1 (g). 2024.

[34] [redacted]. *Exhibit F. Build Transfer Agreement*. Section 19.2. 2024.

[35] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 51.

[36] IPC commented in their final shortlist financial model that "IPC is okay with the redlines."

it excludes direct-assigned interconnection facility costs ($[redacted]) and network upgrades costs ($[redacted]), which are both funded by IPC (the ultimate owner of the facility).[37] Moreover, although the proposal provides a detailed list of cost savings, it does not provide specific dollar amount related to each cost item in the construction costs breakdown. Thus, further clarification is needed to fully understand construction cost components and to ascertain the risk of cost overruns.

LEI reviewed the draft BTA agreement, which contains several measures to address the risk of construction cost overruns:

i. First, the purchase price (BTA) provided is fixed, subject to some exceptions such as events beyond the developer's control.[38] These circumstances include liabilities incurred or unanticipated by the developer due to events such as force majeure and other unforeseen events including delays caused by the buyer, certain interconnection delays, and changes in applicable laws, permits, and transmission provider requirements.[39]

ii. Second, the purchase price (BTA) will be paid as milestone payments, ensuring that the payments are linked to tangible progress and deliverables.[40]

iii. Third, there is a provision for regular reporting and monitoring of construction progress and costs. The developer is required to provide the purchaser with: (a) a progress report on or before the fifth day of each month for the work performed during the previous month; and (b) progress meetings held once every two weeks convened by the developer, as deemed necessary by the purchaser.[41]

iv. In addition to termination due to a force majeure event, if the BTA is terminated due to developer ([redacted]) default, IPC is entitled to seek all damages available at law.[42]

With respect to milestone payments, [redacted] proposed progress payment schedule is split into close to 30 detailed construction milestones (for illustrative purposes, these include, among others, site mobilization, 50% DC collection, 50% inverters received, 25% racks installed, 100% posts installed, 60% modules placed, mechanical completion, COD, interconnection complete and energized, substantial completion, and final acceptance). At none of these milestones would [redacted]

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37 [redacted] notes that these interconnection and network upgrade costs exclude any fees and financing costs, assuming that [redacted] or IPC would cover these costs themselves.

38 [redacted]. *Exhibit F. Build Transfer Agreement*. Section 2.6. 2024.

39 Ibid.

40 [redacted]. *Exhibit F. Build Transfer Agreement*. Section 2.7. 2024.

41 [redacted]. *Exhibit F. Build Transfer Agreement*. Section 11.6 & 11.7. 2024.

42 [redacted]. *Exhibit F. Build Transfer Agreement*. Section 26.1. 2024.

receive more than 12% of the total project payment—incentivizing the company to honor the schedule and deliver the project.

Reasonableness of FOR

[redacted] is proposing a 0.5% FOR for the [redacted] project, which suggests that the plant will be available to perform almost 100% of the time. The ability of a solar plant to perform when requested would hinge on a very efficient maintenance schedule and other factors including the equipment's overall performance, availability of spare parts, etc. The availability of a plant could nonetheless be impacted by external forces such as extreme weather conditions, cyber-attacks, or others.

End effect values

The [redacted] project does not mention any end-of-life plan or include decommissioning costs. Decommissioning a solar PV system typically includes removing the PV array and all balance-of-system equipment, as well as restoring land or infrastructure to its original condition or for new use.[43] Other costs such as labor and shipment should be considered. Moreover, major components, such as PV modules, inverters or transformers, and metal parts may be used as spare parts or recycled with some salvage value.[44] According to NREL, the net cost estimate (including salvage value) for decommissioning per solar PV system is $368,000/MW.[45] Accordingly, [redacted] would have a decommissioning cost of $121.4 million (based on 330 MW).

Environmental emissions costs

Given the absence of emissions associated with solar PV, environmental emissions costs are not applicable. The IE is assessing this criterion from the perspective of Scope 1 emissions.[46]

Reasonableness of operation and maintenance costs

[redacted] FOM costs consist of (1) $[redacted]/kW-year of O&M administrative costs and preventive maintenance, (2) $[redacted]/kW-year of land lease payment, and (3) $[redacted]/kW-year of insurance, amounting to a total cost of $[redacted]/kW-year, escalating at 2.5% annually. LEI notes that the total cost excludes, among others, property taxes, which are yet to be discussed between [redacted] and IPC. LEI notes that the FOM costs are lower than some of the industry benchmark FOM costs listed in Figure 1; this is in part due to the exclusion of other costs such as property taxes and insurance.

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[43] NREL. *A survey of federal and state-level solar system decommissioning policies in the United States*. December 2021.

[44] NREL. *Best practices at the end of photovoltaic system performance period*. February 2021.

[45] Ibid.

[46] Scope 1 emissions are direct greenhouse gas emissions that occur from sources that are controlled/owned by an entity. For the [redacted] project, this would be emissions related to the operation of the solar PV facility.

Figure 1. Comparing [redacted] FOM costs with other sources ($/kW-year)

Source	$/kW-year	Notes
[redacted]	[redacted]	Solar PV with tracking (330 MW)
NREL 2024 v2 ATB	$21.61	Utility-Scale, Class 5 PV*
EIA AEO 2023	$17.16	Solar PV with tracking (150 MW)

Notes: Class 5 PV has an alternating current capacity factor of 28.3%; [redacted] has an alternating current capacity factor of 28.2%.

Sources: NREL 2024 v2 ATB 2024, US Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") 2023, [redacted] Bid Entry Form 2028 RFP.

In addition to FOM costs, [redacted] also proposes VOM costs. The VOM costs cover reactive maintenance costs required by the site, whereas FOM costs cover preventive routine maintenance costs.[47] The VOM is structured as follows: $[redacted]/MWh, with no escalation, for year 1 to year 5; then $[redacted]/MWh, escalating at 6% annually, for year 6 to year 29; and finally, $[redacted]/MWh, with no escalation, for year 30 to year 35. The cost increase starting in year 6 accounts for equipment warranty expiration.[48]

Adequacy of additional capital costs

[redacted] originally proposed a network upgrade cost of $[redacted].[49] This was later increased to $[redacted].[50] Accordingly, the final asset purchase price is $[redacted].

Moreover, the [redacted] project will utilize PTC of the Inflation Reduction Act ("IRA"). The project expects to generate $[redacted] total in tax credits, assuming a $[redacted]/MWh PTC rate escalating at 2% annually.[51] This will result in savings that can be passed on to consumers.

Reasonableness of performance assumptions for output, heat rate,[52] and power curve

[redacted] proposes a capacity factor of 28.2%,[53] which is in line with what LEI found in other studies for plants with similar tracking capabilities. For instance, in its 2024 Annual Technology Baseline,

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47 [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 26.

48 [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 25.

49 [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 24.

50 IPC updated the cost to $[redacted] in the final shortlist financial model.

51 [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 28.

52 Heat rate is irrelevant to solar units because power is generated without fuel combustion, hence it is not discussed in this section.

53 [redacted]. Bid Entry Form. "BTA pricing" tab. Line 23.

NREL estimates a capacity factor of a class 5 PV solar tracking system at 26.6%.[54] A high capacity factor is beneficial to ratepayers.

Specificity of construction schedule or risk of construction delays

[redacted] provided a development schedule for the [redacted] project. Overall, the project remains in the early stages of pre-construction. [redacted] notes that the schedule can be divided into two segments: 1) interconnection driven by IPC and 2) all other project activities driven by [redacted].

IPC's interconnection timeline has the longest duration (3.5 years from conducting the studies to finalizing construction). The project has elected to be studied as a Network Resource Interconnection Service ("NRIS"), and [redacted] is expected to sign a Generator Interconnection Agreement ("GIA") by Q2 2025.[55] The construction and testing will take approximately three years to complete.

In addition, [redacted] has completed site studies and community outreach.[56] Permitting and engineering design commenced in Q4 2024 and will last until Q4 2025.[57] With respect to equipment procurement, [redacted] notes that the equipment lead time is not a limiting factor to achieve the expected COD of April 1, 2028 even if it were to stretch out from current estimates, and that it assumes that IPC will procure the generator set-up transformers ("GSU") (per IPC's contract terms), which has the longest lead time.[58] The procurement of major equipment began in Q4 2024, with construction commencement expected in Q1 2026, mechanical completion by Q4 2027, and substantial completion by Q1 2028.[59] Overall, [redacted] is confident in meeting the target COD, subject to receipt of the required regulatory approvals. LEI notes that, in its proposed project schedule, [redacted] assumes receipt of PUC approval by early June 2025, which implies require quick turnaround in the contract negotiations phase.

Comments on contract risk

Highlighted below are terms proposed by [redacted] that could either raise (or reduce) the level of contention observed during the 2026 AS RFP contract negotiation process:[60]

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[54] NREL. *2024 v2 Annual Technology Baseline*. 2024.

[55] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 20.

[56] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 15.

[57] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 6.

[58] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 20.

[59] [redacted]. *Exhibit N.* [redacted] *Solar – 330 MWac Solar Generation Project*. September 13, 2024. p. 6.

[60] Based on LEI's notes from 2026 AS RFP contract negotiations meetings.

- ***Event of default***: [redacted] offered redlines on the timeline to cure or claim an event of developer default, extending it from 30 days to 30 business days, which is then consistent with the term for buyer default.[61] Similar requests have been seen in contract negotiations between IPC and counterparties in the 2026 AS RFP process. In fact, for some contracts, parties could not agree on both the characterization of the event of default and the applicable cure period.

- ***Early termination***: [redacted] offered redlines on the termination fee. The original agreement only specifies an early termination fee for which the developer is liable to the buyer. [redacted] added terms specifying an early termination fee for which the buyer is liable to the developer.[62] The redline provides some protection to [redacted]. During the contract negotiations for the 2026 AS RFP, similar topics were discussed between the parties. Developers were asking for a similar/symmetric level of protection.

- ***Purchase price***: [redacted] offered redlines on the price adjustment to allow for both increases and decreases to the purchase price pursuant to any change order.[63] This provides flexibility, as change orders can be positive or negative and not just for buyer-initiated changes. Similar requests were discussed for the 2026 AS RFP where developers sought flexibility on pricing.

- ***Contractor and subcontractors***: [redacted] added a threshold for the aggregated cost of procurement of services or equipment above which the developer will be required to obtain approval of the buyer to engage or contract with the subcontractor.[64] Such redline allows [redacted] to reduce administrative burden since it does not need to obtain approval for every service and equipment supplier. During the contract negotiations process for the 2026 AS RFP, IPC sought to ensure that the threshold was not so high as to result in unnecessarily high costs that are ultimately borne by ratepayers.

2.1.3 [redacted] – [redacted]

[redacted] is proposing the 150 MW [redacted] project through an asset purchase. The BESS would be of lithium iron phosphate chemistry, capable of completing one full cycle per day. It has an asset life of 20 years, which is the maximum timeframe guaranteed by the equipment manufacturer. According to [redacted], the unit has multiple functions: "It can be operated in grid forming, grid supporting, and grid following modes. Additionally, the system can support functions such as virtual inertia, black start capability, frequency & voltage regulation, and ramp

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[61] [redacted]. *Exhibit F. Build Transfer Agreement*. Section 25.1.2024.

[62] [redacted]. *Exhibit F. Build Transfer Agreement.* Section 2.11 (d). 2024.

[63] [redacted]. *Exhibit F. Build Transfer Agreement.* Section 2.6 (b)(v). 2024.

[64] [redacted]. *Exhibit F. Build Transfer Agreement.* Section 8.2 (a). 2024.

rate control…."[65] [redacted] will provide several services, including engineering services, project management, purchase of equipment, remote supervision during civil works, factory acceptance test, commissioning, site acceptance test, and training; it will work with a local partner (based in Idaho) for balance of plant activities. The project was studied for NRIS.

LEI finds several areas of concern with respect to the [redacted] project. Importantly, [redacted] proposal assumes BESS technology from CATL, a Chinese-based company. With the new presidential administration, imports of Chinese BESS units may be limited or subject to tariffs that may render the project more expensive. The proposed project price and design are also subject to [redacted] receiving a notice to proceed ("NTP") and executing all required contracts by mid-March 2025—this leaves little time for contract negotiations. Finally, the project is to be located in Ada County, Idaho, which—as seen in the 2026 RFP process—has been a difficult county from which to obtain the required permitting.

Construction cost overruns

The initially proposed full engineering, procurement, and construction ("EPC") project cost (lump sum price) was $[redacted], inclusive of a two-year warranty; the full EPC price inclusive of financing costs was $[redacted]. The price offer was valid for a period of 45 days effective from September 16, 2024. [redacted] later updated its price to $[redacted], which includes network upgrade costs of $[redacted]; it is unclear whether this price also accounts for financing costs.

[redacted] BESS system consists of CATL's EnerC+ containerized solution, "the most competitive economics in the current pricing environment," according to the submitted bid narrative.[66] LEI understands CATL to be a Chinese-based battery supplier. With the new presidential administration, it remains uncertain whether Chinese BESS technology will be subject to further import restrictions or higher tariffs—the former may prevent the BESS units from being imported into the country, while the latter may further raise the cost of the project and threaten its feasibility. If new federal regulations prevent [redacted] from moving forward with CATL's technology, it remains unclear whether an alternative solution would be proposed and, if so, how technology modification would impact the project's pricing structure.

Specifically with respect to tariffs, the project is subject to the tariff increase on the BESS component, which could also potentially generate some construction cost overruns as tariff rates on lithium-ion (non-EV) batteries under Section 301 of the Trade Act of 1974 are expected to rise from 7.5% to 25% in 2026; tariff rates on general battery parts were already raised from 7.5% to 25% in 2024.[67] We note that these tariffs may be subject to modification under the new presidential administration. Moreover, the MV/LV transformer will be sourced from Mexico, another country that may be subject to increased tariffs under the new presidential administration.

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[65] [redacted]. *RFP Offer Document*. p. 6.

[66] [redacted]. *RFP Offer Document*. p. 2.

[67] The White House. *Fact Sheet: President Biden Takes Action to Protect American Workers and Businesses from China's Unfair Trade Practices*. May 14, 2024.

Furthermore, the project is exposed to exchange rate fluctuations. The pricing assumes a currency exchange rate of EUR/USD at 1.108; changes in the currency exchange rate will be evaluated at the time of the NTP to adjust the pricing accordingly.[68] As such, if EUR gets stronger, the final pricing (in USD) will increase; conversely, if USD gets stronger, the final pricing will decrease.

Finally, the project is expected to benefit from the ITC, where federal tax credit policies under the new presential administration remain unclear. In its bid narrative, [redacted] commits to meeting the prevailing wage and apprenticeship requirements for this project to secure the 30% tax credits provided under Section 48E introduced by the IRA, which would result in savings that can be passed on to consumers.

Reasonableness of FOR

[redacted] is proposing a 0% FOR for the [redacted] project, meaning that the project will always be available to operate when required; this would require a proactive and robust maintenance program. The 0% FOR is within range of what is expected for highly efficient technologies such as BESS. For example, a study performed by the California Energy Commission found that BESS FOR is 5%, which is based on the estimates provided by the California Energy Storage Alliance.[69] The project's planned outage rate is 1%.

End effect values

LEI does not believe that [redacted] provided any end-of-life plan for the proposed [redacted] project or include project decommissioning costs. In a BESS decommissioning plan prepared by Stantec for Wisconsin Power and Light Company in January 2023, it was estimated that total decommissioning and recycling costs are about $10.7 million for a 99 MW BESS unit (smaller than the proposed [redacted] facility).[70] Moreover, decommissioning and recycling costs will vary depending on the specific battery chemistry, the recycling approach used, the amount of onsite versus offsite labor employed in disassembling the BESS, and the distance between the BESS site and the processing facility.

Environmental emissions costs

Given the absence of emissions associated with BESS, environmental emissions costs are not applicable. The IE is assessing this criterion from the perspective of Scope 1 emissions.[71]

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[68] [redacted]. *EE24040_IdahoPower_*[redacted] *Energy Storage 2_Pricing Narrative_01*. p. 6.

[69] California Energy Commission. *Midterm Reliability Analysis*. September 2021. p. A-10.

[70] Wisconsin Power and Light Company. *Edgewater BESS Project - Decommissioning Plan*. Docket No. 6680-CE-184. January 5, 2023. p. 7.

[71] Scope 1 emissions are direct greenhouse gas emissions that occur from sources that are controlled/owned by an entity. For the [redacted] project, this would be emissions related to the operation of the BESS facility.

Reasonableness of FOM costs

[redacted] proposes the following operations fees:

- A Long-Term Service Agreement ("LTSA") annual fee (for the full 20-year life of the asset) of $[redacted], subject to revision based on specific LTSA terms and conditions agreed upon between IPC and [redacted];

- a fixed escalation of 3% yearly, subject to renegotiation if the inflation rate exceeds 7%;

- a non-binding lump sum augmentation fee through year 20 of the project's life of $1[redacted] on top of the LTSA fee. Based on LEI's understanding of [redacted] pricing narrative,[72] this augmentation fee would apply on top of the overbuild strategy for the project, which will account for battery degradation in the first two years of operations. LEI also understands that this lump sum fee was adjusted since bid submission, rising to approximately $[redacted][73];

- a product warranty extension yearly price of $[redacted] (on top of the LTSA) for up to 20 years over the initial two-year product warranty; this warranty would not apply to the MV/LV transformer, whose warranty can only be extended until year 5.

This would mean an initial FOM cost (consisting of just the LTSA annual fee) to be $[redacted]/kW-year that then escalates at 3% annually. This FOM cost is lower than the industry benchmark, likely because of the exclusion of auxiliary power, property taxes, and insurance costs, as well as augmentation costs.[74] For example, NREL suggests a range for FOM of $25/kW-year to $99/kW-year[75] while the EIA suggests $40/kW-year.[76] Nevertheless, the relatively lower level of augmentation costs ($[redacted]/kW-year)[77] indicates that overall FOM costs inclusive of all major components would still be far below the industry benchmark. It is likely that the FOM costs are currently underestimated.

The augmentation proposed for the project would account for two years of battery degradation, assuming one cycle per day; the overbuild strategy adopted for the project allows the system to maintain its full operational capacity without any augmentation during the first two years of

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[72] [redacted]. *Pricing Narrative*. p. 4-6.

[73] This $[redacted] figure was derived by LEI based on an augmentation fee of $[redacted]/kW-month.

[74] Augmentation costs are generally supplier-specific and could be driven by parameters including contract terms, supplier's business model, risk appetite, proposed technology, size of installation, and market conditions, among others.

[75] NREL. *Annual technology baseline*. 2022 electricity ATB technologies and data overview. 2022.

[76] EIA. *Capital cost and performance characteristics for utility-scale electric power generating technologies.* January 2024.

[77] [redacted]. *Price Update Form 11-4-2024.xlsx*. "BTA Pricing" tab. Line 23.

operation. [redacted] longer-term augmentation plan would be to install additional equipment in years 3 and 9 of the project's life, which will increase the BESS's energy capacity and as such enable it to maintain 600 MWh of output through year 20 of operations.

Adequacy of additional capital costs

There are no additional capital costs expected to be incurred for network and interconnection costs as [redacted] has included network upgrade costs into its total cost.

Reasonableness of performance assumptions for output, heat rate,[78] and power curve

The [redacted] project is designed to provide uninterrupted power over four hours during peak usage periods and deliver a more extended discharge duration when energy demand is low. It has a capacity factor of around 17%. These performance assumptions align with industry performance expectations for a four-hour utility-scale BESS.[79]

The facility's roundtrip efficiency is estimated at 85%. This is slightly lower than the 86% roundtrip efficiency adopted by NREL; it nonetheless falls within the range of 83-87% identified through testing.[80]

In addition to the project's two-year *product* warranty starting from COD, [redacted] also proposes a two-year *battery capacity* guarantee starting from COD, which can be extended for up to 20 years (this will be included within the scope of the LTSA). Though for reference only, the proposal also provides performance values for years 21-25 based "on the potential of the battery's chemistry." Additional guarantees (especially those that cover the life of the asset) provide greater assurance that the facility will operate at the expected performance level.

Specificity of construction schedule or risk of construction delays

The project is to be located on property owned by IPC; as such, site control and site access are already in place. Despite this progress, LEI sees two potential risks to keeping to the construction schedule.

First, the lead times and delivery schedules for the proposed project are based on [redacted] receiving the NTP from IPC by March 14, 2025, concurrently with the execution of contracts. This indicative schedule would allow the project to achieve full commissioning by March 5, 2027. IPC and [redacted] would need to execute the BTA and have clarity on BESS import and/or tariff challenges within the next 1.5 months to meet this timeline.

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78 Heat rate is irrelevant to BESS units because power is generated without fuel combustion, hence it is not discussed in this section.

79 NREL suggests a capacity factor of 17% for a four-hour utility-scale BESS. Source: NREL. *2024 v2 ATB 2024.*

80 NREL. *Annual Technology Baseline. Utility-Scale Battery Storage*. 2022.

Second, the project is to be located in Ada County, Idaho. As seen in the 2026 RFP process, some developers have experienced difficulty in obtaining public buy-in for project development.

Comments on contract risk

[redacted] provided proposed edits and comments to IPC's draft BTA, noting that its redlines reflect a preliminary review of the contract and that more comprehensive feedback will be provided in the next stage of the process. However, there is already a significant amount of markup to the draft BTA on important contract terms including, but not limited to: definition of delay, what constitutes a change in law, force majeure, material adverse change, taxes, liabilities, insurance, conditions for completion of closing, early termination, credit support, buyer and seller covenants, obligations prior to closing, terms related to schedule, performance testing, EPC milestones and transfer, repair of defects and serial defects, liquidated damages, indemnification, and what constitutes prohibited technology.

In addition, the payment terms provided by [redacted] are for "reference purposes only" but indicate the developer's interest in receiving 90% of the asset purchase price by closing (which, though not clear, LEI understands would either be financial close or close of negotiations); the next 5% would be paid out at substantial completion and the remaining 5% during punch list holdback. Paying the majority of the project price upfront poses a risk to ratepayers, who have to pay in advance for a project that does not yet exist.

2.2 Key takeaways

LEI's review of these BTA project aligns with the positions of these projects in the Final Shortlist rank (shown in Figure 2)—with [redacted] ranking at the top of the list and [redacted] and [redacted] ranking towards the bottom. This may substantiate the approach of beginning negotiations with higher ranking projects first, before moving on to projects lower in rank, like Falcon and [redacted].

Based on its review, LEI does not have any major concerns relating to [redacted] project. While cost and timeline risks exist, they do not seem to be outside the range of what appears to be industry standard. It is yet to be seen whether IPC and [redacted] will agree on contracting terms.

LEI is more concerned about the [redacted] and [redacted] projects. With respect to [redacted], from the IE's perspective, there is significant potential for cost overruns and construction delays. The bid documents fail to provide any certainty with respect to total project costs and propose O&M costs that are remarkably high. If the project will be liable to pay for its carbon emissions, then ratepayers can expect to shoulder an even higher cost. In addition to cost concerns, the project timeline lacks transparency; for instance, it remains unclear when and at what cost the project would be able to interconnect to local natural gas supply lines that would fuel the [redacted] facility. With respect to [redacted], developer [redacted] bid price seems to rely on BESS technology from CATL, a Chinese battery manufacturer. It remains to be seen whether [redacted] will be able to maintain its timing and price commitments under the new presidential administration. Moreover, as seen in the 2026 RFP process, developers have experienced difficulty in obtaining the required permits from Ada County, another potential obstacle to project development.

Figure 2. Ranking of Final Shortlist Bids

Delivery Year	Project	Project owner	Technology and capacity	Bid type
2028	[redacted]	[redacted]	330 MW solar	Resource-based product
2028	[redacted]	[redacted]	80 MW solar	Resource-based product
2028	[redacted]	[redacted]	149 MW solar	Resource-based product
2028	[redacted]	[redacted]	178.6 MW wind	Resource-based product
2028	[redacted]	[redacted]	400 MW solar	Resource-based product
2028	[redacted]	[redacted]	150 MW BESS	Resource-based product
2028	[redacted]	[redacted]	200 MW BESS	Resource-based product
2028	[redacted]	[redacted]	110 MW gas + 110 MW BESS	Resource-based product

*[redacted] and [redacted] are two projects under further review.

3 Sensitivity Analysis on ITC/PTC resale value

In the OPUC Staff report dated July 29, 2024,[81] the Commission expressed concerns over a scenario in which a high resale value of ITC/PTC credits (on the secondary market) could favorably impact utility-owned bids by making them more cost-effective, as a result allowing these utility-owned projects to outbid PPA or BSA bids if the ITC/PTC credits are already baked into their prices. This concern led Staff to propose Scoring and Modeling Methodology Condition 4, or "SMM Condition 4," which requires that IPC work with the IE to develop a sensitivity analysis that evaluates the impact of a range of ITC and PTC discount rates on bids. In order to respond to SMM Condition 4, IPC carried out a sensitivity analysis to evaluate the assumptions of the resale value of the ITC and PTC on bids' overall scores and relative rankings within the Initial Shortlist ("ISL").

3.1 Methodology

The ISL was chosen as the sample for the sensitivity analysis because bid prices have a direct impact on the overall ranking of bids. In the 2028 AS RFP modeling analysis underlying the evaluation of the bids, IPC used ITC and PTC discount rates of 8% and 5%, respectively (applied to the full credits). IPC tested two additional scenarios, as follows:

- a 15% discount on the credit value (85% of ITC/PTC value);
- a 20% discount on the credit value (80% of the ITC/PTC value).

For each case, IPC recalculated the price score of each BTA bid and updated the ranking. Given that the ITC/PTC assumptions only apply to utility-owned bids, all PPA and BSA bids were excluded from the analysis; this includes most of the solar and BESS projects in the ISL.

3.2 Key observations

Overall, the impact of ITC/PTC resale value assumptions on the ranking of utility-owned bids can be considered marginal; while we observed some changes in the overall scores of the asset purchase bids, it hardly resulted in ranking changes leading to modification of the ISL. However, it is worth highlighting key observations by technology group. In fact, while the ranking of the bids selected for the ISL appears to be hardly sensitive to assumptions on ITC/PTC resale value in general, the overall scores of the bids are nonetheless affected by the assumptions. In one case in particular, the impact on the overall score put the bid at risk of dropping out of the final ISL (see discussion below for more details). In this respect, it would be reasonable and appropriate to continue monitoring the impact of such assumptions in future procurement processes, especially during selection for the ISL.

- Bids that are "alone" within their technology categories such as [redacted] (wind & BESS), [redacted] (gas-H2 & BESS), and [redacted] (BESS & energy) were not affected

[81] OPUC. *Staff Report*. Docket No. UM 2317. July 29, 2024.

by the sensitivity analysis—because as the "only" bids, they were automatically selected for the ISL.

- In the wind technology group, under the 15% and 20% discount rate scenarios, [redacted] Wind's overall score dropped from 95 to 90. While this only leaves [redacted] with a 0.6-point lead over the score (89.4) of the other wind-only bid in the group ([redacted]), the [redacted] project remains the only viable option in this group [redacted].

- In the BESS technology group, the drop in overall bid scores (under the 15% and 20% discount rate scenarios) had no impact on the ISL; the top bids remain the same across the scenarios. We did, however, notice a change in the ranking of a few projects such as [redacted], moving up above [redacted], which became relatively more expensive (and less cost competitive) due to lower ITC/PTC credits. However, none of these bids' rankings improved sufficiently to qualify for the final ISL.

- Interestingly, in the solar-only group, higher ITC/PTC discount rates resulted in the exclusion of one selected bid from the ISL. Lower ITC and PTC values dropped the price score of the [redacted] bids from 37.4 to 33.5 and 31.4 in the 15% and 20% discount rates scenarios, respectively. As a result, the overall bid scores decreased from 62.4 to 58.5 and 56.4 under the 15% and 20% discount rates scenarios, respectively. The bids lost their relative competitiveness and exited the final ISL.[82]

- No impact on the ISL was observed in the solar & BESS group given that this group is dominated by PPA and BSA bids. Nonetheless, all asset purchase bids were impacted by the higher discount rate; some were more impacted than others. For example, the [redacted] project's overall score dropped 10 points (from 55.8 to 44.5) under the 15% and 20% discount rates scenarios; the bids dropped 8 ranks.

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[82] Note that neither of these bids were selected for the Final Shortlist.

CERTIFICATE OF SERVICE

I certify that on this March 12, 2025 a true and correct copy of London Economics International, LLC's **CONFIDENTIAL Supplemental to Closing Report, 2028 All Source Request for Proposals for Peak Capacity and Energy Resources** was served on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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