RIDER C
PERFORMANCE MONITORING AGREEMENT

Note: *This Draft Performance Monitoring Agreement will be negotiated during final contract negotiations after the Cal Poly Humboldt Battery Energy Storage System RFP is awarded. The net campus electrical loads will be changing over the next five years as multiple large new buildings are constructed, and as the 3 Megawatts of solar PV are added to the campus grid as a result of the Cal Poly Humboldt Solar Photovoltaic RFP. Due to the uncertainty of the net load growth, a demand charge and bill management performance guarantee is not a requirement of this RFP. This Performance Monitoring Agreement will be used instead. Milestones such as solar PV project completion and the commissioning of new buildings will trigger recalibration of the BESS dispatch optimization model as the polytechnic facilities come online.*

In order to ensure that the BESS dispatch algorithm is performing as expected and the campus is capturing sufficient utility bill savings, the System Provider will submit a monthly BESS Performance Report (BPR) with their monthly invoice. The overall goal of the BPR is to estimate the bill savings achieved from battery dispatch and to track the quality of the optimization algorithm by comparing solar and load forecasts to the actual metered values.

The BPR will include the following Sections:

1. Actual Monthly Campus Net Load Profile (Including Battery Dispatch)
    a. The purpose of this section is to show the actual demand curve so that Cal Poly Humboldt Staff can cross check the monthly performance of the system with the actual PG&E billing. Note that BPR start and end dates must be aligned with the PG&E billing period dates.
    b. What is provided in BPR:
        i. MS Excel Spreadsheet with 15-minute interval data for the billing period
            1. Metering point will be the existing meter at the Point of Common Coupling (PCC) between the Campus Grid and the PG&E grid
        ii. Table 1: Summary of the peak demand and total energy for each rate period for the B20 Option S Rate Schedule (See example below) and the sum total charges from those demand and energy.
2. Counterfactual Monthly Campus Net Load Profile
    a. The purpose of this section is to show the counterfactual unmanaged demand curve so that Cal Poly Humboldt Staff can estimate what demand charges would have been incurred if the BESS was not installed and operated to provide monthly bill savings through demand charge management
    b. What is provided in BPR: MS Excel Spreadsheet with counter-factual interval data for the billing period
        i. Metering points:
            1. Existing meter at the PCC between the Campus Grid and the PG&E grid
            2. BESS Meter at the PCC of Feeder 4 and the Campus Grid
        ii. Counterfactual load profile will be Metering Point No. 1 minus Metering Point No. 2
            1. Directional power flow conventions:
                a. At the PCC with PG&E Grid: Negative when importing
                b. At the PCC with BESS (Feeder 4 breaker): Negative when charging battery
        iii. Table 2: Summary of the counterfactual peak demand and total energy for each rate period for the B20 Option S Rate Schedule (See example below) and the sum total charges that would have been incurred by those demand and energy charges. The difference between this counterfactual bill and the actual estimated bill (as estimated in item 1) is the estimate for the bill savings from the battery operation.

3. Perfect Forecast versus Actual Forecast Comparison
    a. The effectiveness of the BESS dispatch algorithm used by the System Provider to provide monthly bill savings from demand charge management will depend on accurate campus load and solar PV production forecasts. The purpose of this section is to compare the actual campus load and solar PV generation to the values forecasted by the System Provider's optimization model as a measure of how well the optimization model is performing.
    b. MS Excel Spreadsheet with interval forecast and actual data for the current billing data
        i. Input data:
            1. Counterfactual Net Load Profile from Section 2
            2. Forecasted campus load that was used to inform the System Provider's optimization and dispatch model
                a. Synchronous campus load forecast data for each 15-minute interval as written to a historian program at the end of each optimization run
            3. Forecasted solar PV production that was used to inform the System Provider's optimization and dispatch model
                a. Synchronous solar PV forecast data for each 15-minute interval as written to a historian program at the end of each optimization run
        ii. Results
            1. Synchronous comparison of counterfactual net load profile against the forecasted net load (the forecasted campus load minus the forecasted solar PV production)
                a. A graphical depiction of the actual campus load versus the forecasted net campus load with error bars showing agreed upon confidence intervals.
            2. If the forecasted net load deviates significantly outside agreed upon confidence intervals the System Provider may be required to update/tune their forecast models and/or a pre-negotiated remedy may become effective to compensate the Trustees for expected bill savings that were not realized.

Summer Example								
Table 1: Summary of peak demand for each rate period for B20 Option S Rate Unbundled Schedule								
					Rates ($/kW)			
	Managed Demand				0.53	0.04	2.54	12.85
Date	Max Peak Demand Summer (per day, 4=9PM, kW)	Max Part-Peak Demand Summer (per day, 2-4PM and 9-11PM, kW)	Max Demand (per month, all hours except 9AM to 2PM, kW)	Max Monthly Demand (per month, kW))	Max Peak Demand Summer Cost	Max Part-Peak Demand Summer Cost	Max Demand Cost	Max Monthly Demand Cost
7/1/24	-1700	-2600			$ 901.00	$ 104.00		
7/2/24	-1700	-2600			$ 901.00	$ 104.00		
7/3/24	-1700	-2600			$ 901.00	$ 104.00		
7/4/24	-1700	-2600			$ 901.00	$ 104.00		
7/5/24	-1700	-2600			$ 901.00	$ 104.00		
7/6/24	-1700	-2600			$ 901.00	$ 104.00		
7/7/24	-1700	-2600			$ 901.00	$ 104.00		
7/8/24	-1700	-2600			$ 901.00	$ 104.00		
7/9/24	-1700	-2600			$ 901.00	$ 104.00		
7/10/24	-1700	-2600			$ 901.00	$ 104.00		
7/11/24	-1700	-2600			$ 901.00	$ 104.00		
7/12/24	-1700	-2600			$ 901.00	$ 104.00		
7/13/24	-1700	-2600			$ 901.00	$ 104.00		
7/14/24	-1700	-2600	-4650	-4650	$ 901.00	$ 104.00	$ 11,811.00	$ 59,752.50
7/15/24	-1700	-2600			$ 901.00	$ 104.00		
7/16/24	-1700	-2600			$ 901.00	$ 104.00		
7/17/24	-1700	-2600			$ 901.00	$ 104.00		
7/18/24	-1700	-2600			$ 901.00	$ 104.00		
7/19/24	-1700	-2600			$ 901.00	$ 104.00		
7/20/24	-1700	-2600			$ 901.00	$ 104.00		
7/21/24	-1700	-2600			$ 901.00	$ 104.00		
7/22/24	-1700	-2600			$ 901.00	$ 104.00		
7/23/24	-1700	-2600			$ 901.00	$ 104.00		
7/24/24	-1700	-2600			$ 901.00	$ 104.00		
7/25/24	-1700	-2600			$ 901.00	$ 104.00		
7/26/24	-1700	-2600			$ 901.00	$ 104.00		
7/27/24	-1700	-2600			$ 901.00	$ 104.00		
7/28/24	-1700	-2600			$ 901.00	$ 104.00		
7/29/24	-1700	-2600			$ 901.00	$ 104.00		
7/30/24	-1700	-2600			$ 901.00	$ 104.00		
7/31/24	-1700	-2600			$ 901.00	$ 104.00		
				Subtotals-->	$ 27,931.00	$ 3,224.00	$ 11,811.00	$ 59,752.50
							Total -->	**$ 102,718.50**

Summer Example								
Table 2: Summary of counterfactual demand for each rate period for B20 Option S Rate Schedule								
					Rates ($/kW)			
	Counterfactual Unmanaged Demand				0.53	0.04	2.54	12.85
Date	Max Peak Demand Summer (per day, 4=9PM, kW)	Max Part-Peak Demand Summer (per day, 2-4PM and 9-11PM, kW)	Max Demand (per month, all hours except 9AM to 2PM, kW)	Max Monthly Demand (per month, kW))	Max Peak Demand Summer Cost	Max Part-Peak Demand Summer Cost	Max Demand Cost	Max Monthly Demand Cost
7/1/24	-2336.2	-2058.5			$ 1,238.21	$ 82.34		
7/2/24	-2427.2	-2066.7			$ 1,286.40	$ 82.67		
7/3/24	-2608.4	-2032.8			$ 1,382.46	$ 81.31		
7/4/24	-2962.6	-2040.2			$ 1,570.18	$ 81.61		
7/5/24	-3478.0	-1962.6			$ 1,843.35	$ 78.51		
7/6/24	-3645.5	-2015.4			$ 1,932.12	$ 80.62		
7/7/24	-3836.4	-2109.6			$ 2,033.27	$ 84.38		
7/8/24	-4188.0	-2167.4			$ 2,219.65	$ 86.70		
7/9/24	-4267.1	-3689.3			$ 2,261.54	$ 147.57		
7/10/24	-4419.5	-3484.8	-4318.1		$ 2,342.32	$ 139.39	$ 10,967.97	
7/11/24	-4434.0	-3427.2			$ 2,350.04	$ 137.09		
7/12/24	-4478.4	-3139.2			$ 2,373.55	$ 125.57		
7/13/24	-4377.6	-3156.5			$ 2,320.13	$ 126.26		
7/14/24	-4288.3	-3090.2			$ 2,272.81	$ 123.61		
7/15/24	-4236.5	-3038.4		-4478.4	$ 2,245.33	$ 121.54		$ 57,547.44
7/16/24	-4124.2	-2972.2			$ 2,185.80	$ 118.89		
7/17/24	-4037.8	-2058.5			$ 2,140.01	$ 82.34		
7/18/24	-3916.8	-2066.7			$ 2,075.90	$ 82.67		
7/19/24	-3865.0	-2032.8			$ 2,048.43	$ 81.31		
7/20/24	-3844.8	-2040.2			$ 2,037.74	$ 81.61		
7/21/24	-3738.2	-1962.6			$ 1,981.27	$ 78.51		
7/22/24	-4188.0	-2015.4			$ 2,219.65	$ 80.62		
7/23/24	-4267.1	-2109.6			$ 2,261.54	$ 84.38		
7/24/24	-4419.5	-2167.4			$ 2,342.32	$ 86.70		
7/25/24	-4434.0	-3689.3			$ 2,350.04	$ 147.57		
7/26/24	-4478.4	-3484.8			$ 2,373.55	$ 139.39		
7/27/24	-4377.6	-3427.2			$ 2,320.13	$ 137.09		
7/28/24	-4288.3	-3139.2			$ 2,272.81	$ 125.57		
7/29/24	-4236.5	-3156.5			$ 2,245.33	$ 126.26		
7/30/24	-4124.2	-3090.2			$ 2,185.80	$ 123.61		
7/31/24	-4037.8	-3038.4			$ 2,140.01	$ 121.54		
					$ 64,851.72	$ 3,277.19	$ 10,967.97	$ 57,547.44
							Total -->	**$ 136,644.32**

End of Rider C