**Subject:** **Avoided Cost of Load Shifting (ACLS): Computational Procedure**

**Date:** **September 29, 2025**

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## 1.0 Introduction

This memo describes how staff have estimated our avoided costs associated with customer load shifting efforts, specifically with respect to new customer-sided battery energy storage (BES) systems installed with either new or existing solar PV systems. This methodology has been directly adapted from our current avoided cost of energy (ACOE) "desktop" calculation methodology for determining the appropriate value of renewable energy from customer owned distributed energy resources – specifically solar PV resources. As such, Table 1 shows the ACOE components that would also apply to such load shifting efforts, referred to as an ACLS calculation throughout the remainder of this memo.

## 2.0 High-level Calculation Methodology

Staff has developed a practical "value-of-load-shifting" calculation methodology that can be used to determine at least some of the $/kWh rebate amount that RPU should pay for encouraging customer-sided BES systems. Additionally, this calculation methodology also produces an estimate of the expected revenue (or avoided energy costs) a customer can expect to capture when they use a BES for daily load shifting purposes. As adapted from our current ACOE calculations, a high-level description of how each component can be calculated is presented in Table 1. Additional details concerning the calculation of each cost component are presented after this table.

Note that Table 1 and the subsequent discussion do not include any calculations concerning local distribution benefits. Distribution system benefits for new customer-sided battery energy storage (BES) systems are calculated separately by Energy Delivery Engineering staff. When available, these can then be added (after the fact) to the calculated benefits discussed here.

**Table 1.** Avoided cost of load shifting (ACLS) desktop calculation methodology.

| Component (Avoided Costs) | Metrics (used in calculations) | Proposed Methodology (for deriving avoided cost [value] estimate) | Notes |
|---|---|---|---|
| **Energy** | Most recent three years of average hourly LMP values at MLAP_RVSD, calculated by month. Expected monthly charge and discharge energy amounts from the BES. Current DTOU Mid-peak and On-peak rates, along with current excess solar reimbursement rates. | Calculate a monthly weighted load-shift value by multiplying the average hourly LMP values with the expected BES charging and discharging levels. This load-shift value can then be turned into a $/month credit by multiplying the LS value by the number of days in the month. A similar approach is used to estimate the customer's LS energy benefit (e.g., by replacing LMP values with weighted retail rates). | *Quantifies the direct avoided local energy costs associated with shifting daily loads from the evening into midday hours.*<br><br>*These avoided costs should be compared to the average rate induced load shifting benefits received by the customer (and set to 0 if these benefits are greater than the avoided costs).* |
| **Capacity (System RA)** | kW $/month system RA costs. Probability of Peak hour falling within daily diurnal discharge event. | Use seasonally weighted monthly system RA costs ($/kW-month), multiply each monthly cost by expected peak hour BES capacity factor (CF), sum results to determine system RA credit. | *Quantifies the direct avoided system capacity costs, based on input $/kW system cost estimates. Uses annual (seasonally weighted) system RA costs from most recent two years.* |
| **Capacity (Local RA)** | None. | No credit. | *See section 3.3.* |
| **Ancillary Services** | None. | No credit. | *See section 3.4.* |
| **Environmental (Carbon Credit)** | Uses the last four quarterly CARB Auction clearing prices, along with along with a basic assumption about charging and discharging emission factors. | Multiply the appropriate average four quarter carbon price by the by the difference in the emission factors to determine the implied $/MWh carbon credit. | *These avoided costs are subjective (accuracy depends upon assumptions about displaced energy sources).* |
| **RPS Credit** | None. | No credit. | *See section 3.6.* |
| **Transmission** | None. | No credit. | *See section 3.7.* |
| **System Losses** | Ave distribution loss factor (proportion), assumed to be 5.4%. | Divide sum of $/kWh components (Energy, Capacity, and Carbon) by 1 – loss factor. | *Adjusts (inflates) avoided cost components to account for distribution system losses.* |

## 3.0 Desktop Calculations

The following notes provide further clarification about how each ACLS component should be calculated and/or updated on an annual basis.

### 3.1 Energy

The wholesale Energy credit calculation is designed to correctly reflect the avoided wholesale energy costs at the MLAP_RVSD p-node when a customer-sided BES is used to shift energy consumption from the evening peak hours to the midday solar hours. To perform this calculation, the average DA LMP prices for the RVSD p-node must first be determined for each monthly 24-hour diurnal pattern (e.g., a [24 x 12] LMP price matrix, representing the 288 diurnal by month price vector). The elements in this matrix can then be multiplied with the corresponding assumed monthly charging and discharging patterns to determine the daily "load-shift" energy value. This value can then be converted into a $/month credit by multiplying the load-shift value by the number of days in each month.

Once computed, these wholesale energy credits should be compared to the average rate induced load shifting benefits that the customer expects to receive under their current Domestic TOU rate plan. If/when these load shifting benefits exceed the calculated wholesale energy credits, then the customer should not receive any wholesale energy credit in the calculated rebate (because the customer will already capture greater energy benefits in the form of reduced retail energy bills).

Our current procedure uses the most recent three years of MLAP_RVSD LMP price data to compute the wholesale energy credits. A second "price" matrix needs to be used to calculate the load shifting benefits. These prices are a function of DTOU winter and summer Mid-peak and On-peak energy rates, as well as the winter and summer payment rates for excess PV energy injected back into the distribution system. The analyst should specify what percentage of (charging and discharging) energy corresponds to each rate to compute the weighted average load shifting (LS) rates used in the second price matrix.

### 3.2 Capacity – System RA

The System RA Capacity credit quantifies the avoided system capacity costs that locally installed BES systems are expected to offset. To perform this calculation, the maximum RPU peak system load hour for each day needs to be identified and then these counts need to be summed up by month. The count (frequency) elements in this matrix can then be compared to the assumed discharge hours in order to calculate the expected BES peak capacity factors (by month).

Like the energy price calculations, we currently use the most recent three years of RPU hourly system load data in this frequency analysis. This frequency matrix can then be used to generate the expected monthly BES capacity values. Note that in these calculations we assume that a 4-hour BES system is discharged for 5 hours at 80% of its maximum discharge rate, uniformly over the 5-hour DTOU On-peak time-period.

In addition to these calculations, we also need an estimate of our current system capacity cost (expressed on a $/kW-year basis). Our current procedure calls for calculating this value based on the most recent previous two years of forward procured RA costs.

### 3.3 Capacity – Local RA

A Local RA Capacity credit only showed up in our ACOE calculations because a customer-sided solar PV system generates energy that in turn reduces our system loads. However, a customer-sided BES system will not reduce a customer's energy consumption but rather increases it (slightly). Thus, because there is no reduction in overall energy usage, there can be no reduction in Local RA needs, in turn negating this credit.

### 3.4 Ancillary Services

Like the Local RA Capacity credit, an Ancillary Services (AS) credit can only occur if there is an overall reduction in our system loads. In the absence of this, the AS credit should be set to 0.

### 3.5 GHG Carbon Credit

The GHG (Environmental) Carbon Credit calculation is based on the average of the previous four quarterly CARB auction clearing prices, along with some assumptions about the emission factors associated with the consumed and displaced energy. The auction clearing prices should be obtained directly from the CARB website.

The ACLS GHG credit is calculated as the average clearing price ($/ton) multiplied by the weighted difference in emission factors (ton/MWh), which in turn yields the $/MWh carbon credit. Conceptually, this calculation represents the value of the avoided carbon impact obtained from the customer's load shifting efforts.

### 3.6 RPS Credit

The RPS Credit is not applicable to an ACLS calculation, since a BES is not in itself a renewable energy asset.

### 3.7 Transmission

Like the Local RA Capacity and Ancillary Services credits, there can be no Transmission credit associated with an ACLS calculation because our system loads are not being reduced. This credit should instead be set to 0.

### 3.8 System Losses

RPU distribution system losses are assumed to be 5.4% annually; this value was derived from a comprehensive study of 15 years of system versus retail load data, as reported in our 2021 CEC IEPR Form 4 filing. This loss factor is not expected to change materially in the future, at least not before the completion of the Riverside Transmission Reliability Project (RTRP).

## 4.0 A Hypothetical Example

The following assessment assumes that a customer installs a 1 kW / 4 kWh BES system. This system is assumed to charge every day from 9 AM to 2 PM (at 1 kW/hour) and then discharge during the winter and summer DTOU On-peak hours (at 0.8 kW/hour in each 5-hour window). The monthly "Wholesale Value", "Load Shift Value", and "Rebate Value" calculations should be calculated first, followed by a frequency analysis of the most recent three years of RPU hourly system load data (for determining the monthly "Discharge Peak CF" values).

Under the above assumptions and calculations, we find that the value of the Energy Credit is 0, since the Customer Energy Load Shifting Revenue greatly exceeds this (wholesale) avoided cost component. The value of the System Capacity Credit is calculated to be $0.0381/kWh, while the Environmental Carbon Credit value is found to be $0.0115/kWh. When combined with the $0.0028/kWh Line Loss adjustment, RPU's full avoided costs are calculated to be $0.0523/kWh, or $76.41 per year before accounting for any BES degradation effects.

Since these calculations are based on a 1 kW / 4 kWh BES system, the annual dollar value per dispatchable kWh is equal to $76.41/4 = $19.10. Finally, if we assume a 3% linear degradation effect, the 10-Year dollar value per dispatchable kWh works out to be $162.36, which represents our potential $/kWh rebate amount, before accounting for any additional local distribution benefits and/or critical peak (reduction) benefits. However, it should also be noted that Energy Delivery Engineering staff have determined that the additional local distribution benefits are quite significant on RPU circuits already loaded near their maximum capacity rating. In fact, incorporating these additional benefits over a 10-Year period raises the dollar value per dispatchable kWh to $463.64.

**Subject:** **Avoided Cost of Load Shifting (ACLS) - Distribution**

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RPU estimates distribution avoided costs by first flagging the circuits and transformers that are close to (or above) their capacity limits. For each one, it identifies the standard utility upgrade that would normally be built to address the constraint, then estimates the full project cost, including all major cost components.

Next, it converts that upfront project cost into an annual cost using a carrying-charge style annualization and adds annual operations and maintenance. It then divides the annual cost by the extra capacity the upgrade would provide to get a capacity value in dollars per kW-year, and applies the value in the years when the upgrade would otherwise be needed, with escalation to reflect timing and cost growth.

To use the result in energy-based cost-effectiveness models, RPU converts the capacity value into a dollars-per-kWh equivalent by spreading it over a set of effective peak hours when the constraint is most likely to occur, and adjusts for battery efficiency so it aligns with how storage is modeled.

The overall structure matches CPUC distribution deferral avoided-cost methods[1], but the inputs and project assumptions are tailored to RPU's system.

[1] CPUC 2024 Distributed Energy Resources Avoided Cost Calculator Documentation