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STAFF PROPOSAL

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To: R.25-01-005 Service List

From: Energy Division

Subject: SMJU Customer Generation Tariff Reform: Staff Proposal (R.25-01-005 Track 2)

I. INTRODUCTION

This Staff Proposal presents Energy Division's recommended resolution of several issues related to Track 2 of Rulemaking 25-01-005,¹ which examines the customer generation tariff structures at California's three small multi-jurisdictional utilities (SMJUs): Liberty Utilities (CalPeco Electric) LLC (Liberty), Bear Valley Electric Service (BVES), and PacifiCorp (d/b/a Pacific Power). Quantitative modeling confirms significant and ongoing cost shifts to non-participating ratepayers by solar customers at all three utilities. This proposal is issued for party comment pursuant to the ALJ's ruling.

¹ R.25-01-005, Order Instituting Rulemaking on SMJU Customer Generation Tariffs.
https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R2501005

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SUMMARY OF RECOMMENDATIONS

Energy Division proposes three actions implemented through a single consolidated Tier 2 advice letter per utility:

- Create a **Liberty** Net Billing Tariff (Liberty NBT) with:
 - mandatory TOU import rates,
 - avoided-cost-based export compensation set at a floating percentage of the applicable TOU rate (approximately 10% at current rates, equal to the Liberty-specific avoided cost),

- monthly billing with annual true-up, no non-bypassable charges,
- a 1 MW maximum generating-facility size and a 100 percent annual-load sizing limit;
- and annual Net Surplus Compensation.
- To address cost shift concerns related to equity and building decarbonization, all existing Liberty NEM customers migrate to the Liberty NBT at the time of their next true-up date after 1 January 2027.
- Require **BVES** Schedule DGS and **PacifiCorp** Schedule NB-136 customers:
 - to take service on the highest-differential active TOU import rate offered by each utility.
 - Adopt an annual advice letter process for interconnection fee updates.
 - Transition all BVES Schedule NEM customers to Schedule DGS and all PacifiCorp Schedule NEM customers to Schedule NB-136 at the time of their next true-up date after 1 January 2027.

Key quantitative findings supporting these proposals are summarized in Table A-2 in Appendix A.

Table 1 provides a high-level comparison of the principal design elements of the large-IOU Net Billing Tariff and the proposed SMJU tariff framework, highlighting where the Staff Proposal modifies the large-IOU approach to account for differences in SMJU tariffs, avoided-cost data, billing capabilities, and existing customer-generation programs.

Table 1: Comparison of Large-IOU Net Billing Tariff and Proposed SMJU Tariff Design

Component	Large IOU NBT	Proposed for Liberty	Proposed for BVES	Proposed for PacifiCorp	Reason for Proposed SMJU Approach
Import rate	NBT customers take service on specific TOU rates; NEM 2.0 customers were already subject to TOU requirements.	Highest-differential TOU rate (D-1 residential; A-1 non-residential), including customers migrating from legacy NEM.	Highest-differential available TOU rate; A-4/A-5 for non-residential; residential TOU when available.	Highest-differential TOU rate; DT residential / AT-29 non-residential.	Applies the NBT TOU principle.
Export compensation	Hourly avoided-cost values derived from the Avoided Cost Calculator (ACC).	Liberty-specific avoided cost, implemented as a percentage of the applicable TOU rate (about 10% currently).	Existing - avoided-cost based rate.	Existing Commission-approved NB-136 avoided-cost rates.	No Commission-adopted ACC exists for SMJU balancing authority areas. Utility-specific avoided-cost methodologies are the best available proxies while preserving the principle that exports should reflect avoided costs.

Interconnection fee	Socialized interconnection costs for customers under 1 MW, with reporting/update process under D.22-12-056.	Same methodology as large IOU NBT.	Same methodology as large IOU NBT.	Same methodology as large IOU NBT.	Aligned with large IOU NBT.
Netting / billing	No netting interval; imports billed at retail rate and exports separately credited.	No netting interval; monthly billing; annual true-up.	Existing DGS net billing; monthly settlement.	Existing NB-136 net billing; monthly billing/settlement.	Generally aligned with IOU NBT. Existing BVES and PacifiCorp structures already operate on a net-billing basis and do not require redesign for simplicity.
Non-bypassable charges (NBCs)	NBT customers pay applicable NBCs as prescribed by D.16-01-044.	No NBC mechanism.	No NBC mechanism.	No NBC mechanism.	SMJUs already collect Base Services Charges that recover a portion of fixed grid costs; separate NBC implementation would add billing complexity and could duplicate cost recovery without SMJU-specific analysis.
System sizing	Sizing is limited to 100% of historic consumption. If the customer signs an attestation that they plan to increase load, sizing up to 150% is allowed	100% of annual load and 1 MW maximum.	100% of annual load and 1 MW maximum; existing DGS aggregate cap also remains.	100% of annual load and 1 MW maximum.	A more cautious sizing limit is proposed for the SMJUs given their smaller systems and to limit additional cost-shift exposure.
Legacy / transition treatment	Existing NEM 1.0/2.0 customers retain legacy treatment for 20 years; NBT customers retain	Existing NEM customers migrate to Liberty NBT at first true-up after Jan. 1,	Legacy NEM customers transition to DGS; existing DGS customers remain on DGS but become subject to	Legacy Schedule 135 customers transition to NB-136; existing NB-136 customers remain but become subject to modified terms,	Large-IOU statutory legacy provisions under PU Code § 2827.1 do not apply to SMJUs. Liberty has no previously established CPUC legacy period;

	legacy treatment for 9 years	2027; no new legacy period.	modified terms, including TOU import rates.	including TOU import rates.	BVES/PacifiCorp legacy provisions preserve program participation but the proposal modifies tariff terms.
Net surplus compensation	Annual NSC framework applies to net-surplus exports.	Annual NSC at applicable wholesale/SMJU proxy rate.	Existing DGS treatment retained.	No separate annual NSC; NB-136 continuously compensates exports at Commission-approved avoided-cost rates.	Uses existing SMJU mechanisms where they already satisfy the underlying avoided-cost compensation requirement rather than imposing unnecessary new processes.

II. BACKGROUND

California's three SMJUs have operated customer generation tariffs that have never been subject to the comprehensive cost-effectiveness review applied to large investor-owned utility (IOU) programs. Liberty operates a traditional retail-rate net energy metering tariff (Schedule NEM) under a NEM 1.0 structure that remains open to new customers. BVES and PacifiCorp operate net billing tariffs approved in separate proceedings in 2020 ([D.20-01-008](#)² and [D.20-01-007](#),³ respectively). None has been evaluated against the rate design principles the Commission adopted in D.23-04-040.⁴

Quantitative modeling conducted by Energy Division confirms significant cost-shift concerns at all three utilities. The core methodology computes a solar-weighted average for both the retail rate and the grid avoided cost: for each of the 8,760 hours in a calendar year, the hourly TOU rate and hourly avoided cost are each multiplied by the estimated solar production fraction for that hour, then summed and divided by total annual solar production. This weighting reflects what a solar customer actually receives and what the grid actually avoids, as opposed to simple annual averages that ignore the timing of solar generation.

Because the Avoided Cost Calculator is formally adopted only for the three large investor-owned utilities (PG&E, SCE, and SDG&E), no Commission-adopted ACC exists for the balancing authority areas that serve the SMJUs. Rather than importing large-IOU ACC values as proxies, the cost-effectiveness analysis in this Staff Proposal constructs avoided costs from the ground up using each SMJU's own

² D.20-01-008, Decision Approving Bear Valley Electric Service Distributed Generation Service Tariff (2020).

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D2001008>

³ D.20-01-007, Decision Approving PacifiCorp Net Billing Tariff Schedule NB-136 (2020).

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D2001007>

⁴ D.23-04-040, Decision Adopting Rate Design Principles (2023).

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D2304040>

most recent revenue-requirement record: Liberty's marginal cost of service study from its Test Year 2025 GRC (A.24-09-010) for the Liberty-specific avoided cost, BVES's tariffed NSCR-based avoided energy rate, and PacifiCorp's Commission-approved NB-136 avoided-cost rates. Extending the ACC to the SMJU balancing authority areas would be a separate effort, potentially under [R.22-11-013](#), and is not expected to be completed within the timeline of this proceeding, nor is its outcome known at this time. Energy Division applies the overarching cost-shift and export-compensation principles the Commission adopted in D.22-12-056 for the three large investor-owned utilities to these SMJU-specific inputs.

For Liberty's residential customers on [Schedule TOU D-1](#), the solar-weighted average TOU rate is approximately 49.1 cents/kWh, slightly above the unweighted annual average of 45.9 cents/kWh. Because Liberty's summer on-peak period runs 10:00 a.m. to 10:00 p.m. and its winter mid-peak period runs 7:01 a.m. to 5:00 p.m., solar generation falls predominantly in the higher-priced periods: an hourly Tahoe-basin solar production profile places roughly half of annual output in summer on-peak and most of the remainder in winter mid-peak. Solar exports are therefore credited at a modest premium to the annual average retail rate, not a discount. Energy Division calculates Liberty's solar-weighted avoided cost using Liberty's own Marginal Cost of Service Study from the TY 2025 GRC (A.24-09-010⁵):

- avoided energy at Liberty's flat all-in purchased-power cost under its NV Energy Supply Agreement,
- avoided generation capacity and demand-related distribution weighted by solar's measured coincidence with Liberty's tariff-defined winter on-peak window (approximately 2% of annual solar output),
- customer-related distribution excluded because those costs continue regardless of exports, and avoided GHG from NV Energy's gas-dominant marginal generation.

The result is an avoided cost of approximately 4.94 cents/kWh, constructed entirely from Liberty's own revenue-requirement record with no large-IOU ACC inputs. The overcompensation ratio under the current NEM 1.0 tariff is $49.1/4.94 = 9.9x$ for residential customers, and $47.5/4.94 = 9.6x$ for small commercial customers on Schedule TOU A-1, whose current TOU rates are comparable to those of Schedule TOU D-1.

Two distinct cost shifts arise under the SMJU customer generation tariffs. The first, quantified above, is export overcompensation: exports credited above their avoided cost to the grid. The second is a fixed-cost-recovery cost shift that does not depend on the export rate. Retail volumetric rates recover not only marginal energy cost but also a large share of fixed costs, including distribution, generation capacity, wildfire mitigation, and public purpose program costs, that do not vary with a customer's usage. A customer who serves onsite load with self-generation reduces billed kWh and therefore under-contributes to those fixed costs, even though the customer remains connected to and dependent on the grid. The unrecovered fixed costs are shifted to non-participating customers. Because net billing preserves behind-the-meter self-consumption, this second cost shift persists

⁵ A.24-09-010, Liberty Utilities (CalPeco Electric) Application for Test Year 2025 General Rate Case (filed September 2024). https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A2409010

regardless of how exports are compensated and is not addressed by the export-rate reforms in Section III.

The Base Services Charge (BSC) adopted under [D.24-05-028](#) partially mitigates the fixed-cost-recovery shift by moving a portion of fixed costs from volumetric rates to a fixed monthly charge that customers pay regardless of self-consumption. The adopted standard (non-CARE, Tier 3) BSC is \$31.70 per month for Liberty, \$23.22 per month for BVES, and \$26.34 per month for PacifiCorp single-family customers. The BSC recovers only a fraction of per-customer fixed costs, however. In its BSC filing under D.24-05-028, Liberty classified approximately \$61.5 million of its \$105.45 million base revenue requirement as customer-related fixed costs and identified marginal customer access costs alone of roughly \$79.90 per customer per month, more than double the \$31.70 BSC; BVES similarly identified customer costs of \$46.03 per customer per month against a \$23.22 BSC. A substantial share of fixed costs therefore remains embedded in the SMJUs' volumetric rates, so a material fixed-cost-recovery shift persists even after the BSC takes effect. This bears directly on the no-non-bypassable-charge design in Sections III.E and IV.D, which rely on the BSC to recover fixed costs from customer-generators.

Table 2 summarizes current program status and cost-shift context at each utility.

Table 2. SMJU Customer Generation Program Cost-Shift Summary.

Utility	Program	Rate context	Cost-shift finding
Liberty	Schedule NEM (NEM 1.0, open to new customers)	Rates up ~121% since 2020	Solar-weighted retail rate 49.1¢/kWh (D-1) vs. 4.94¢/kWh avoided cost (constructed from A.24-09-010 GRC revenue requirement) = 9.9x overcompensation (D-1 residential); 9.6x (A-1 small commercial)
BVES	Schedule DGS (net billing, 2020)	Rates up ~106% since 2020	Exports are compensated at the SCE-derived NSCR of 2.55¢/kWh (AL 513-E ⁶), an avoided-energy proxy, so export-side cost shift is limited; the remaining shift is fixed-cost recovery through self-consumption at full retail rates. On this reasoning the DGS RIM ratio falls below 1.0, though far closer to 1.0 than retail-rate

⁶ BVES Advice Letter 513-E, Updating Net Surplus Compensation Rate (effective May 2025). Available at BVES tariff schedules. <https://www.bvesinc.com/customer-service/rates-regulations/general-rate-schedules>

Utility	Program	Rate context	Cost-shift finding
			NEM, and the TRC ratio falls below 1.0 given mountain-climate installed costs against avoided energy value.
PacifiCorp	Schedule NB-136 (net billing, 2020)	Rates up ~29% since 2020	Exports are compensated at fixed avoided-cost rates adopted in D.20-01-007 (12.352¢/kWh on-peak), so export-side cost shift is limited; the remaining shift is fixed-cost recovery through self-consumption. On this reasoning the NB-136 RIM ratio falls below 1.0 but near the large IOU NBT range, and the TRC ratio falls below 1.0 given installed costs against avoided-cost value.

III. PROPOSED LIBERTY NET BILLING TARIFF

Below we discuss the tariff components including import rates, export compensation, interconnection fees, netting intervals, non-bypassable charges, project size limits, net surplus compensation, legacy periods, and billing system updates.

Table 1 above provides a high-level comparison of the principal design elements of the large-IOU Net Billing Tariff and the proposed SMJU tariff framework, highlighting where the Staff Proposal modifies the large-IOU approach to account for differences in SMJU tariffs, avoided-cost data, billing capabilities, and existing customer-generation programs.

A. Mandatory TOU Import Rate

All Liberty NBT customers must take service on the Liberty TOU rate with the highest on-peak/off-peak differential in effect. Customers will be transitioned immediately upon the establishment date of the new TOU rate. As of the date of this Staff Proposal, the applicable rates are Schedule TOU D-1 (residential) and [Schedule TOU A-1](#) (non-residential). The applicable rate is identified in each annual Tier 1 advice letter filing.

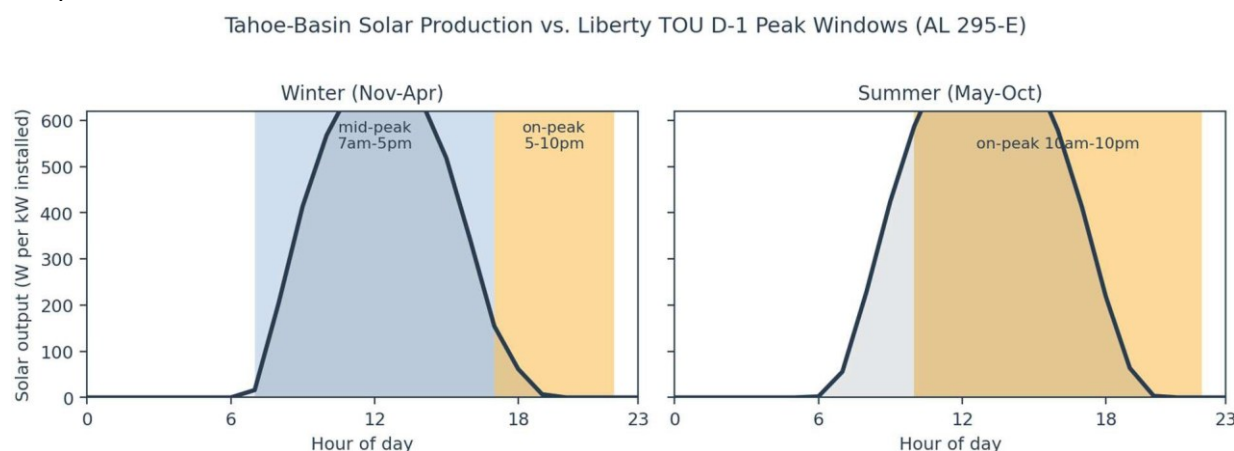
Current Schedule TOU D-1 rates:⁷ Winter on-peak \$0.50320/kWh, mid-peak \$0.49638/kWh, off-peak \$0.41116/kWh; Summer on-peak \$0.49698/kWh, off-peak \$0.40610/kWh. Winter is a three-period

⁷ AL 295-E, effective 1 June 2026.

schedule (off-peak 10:01 p.m. to 7:00 a.m., mid-peak 7:01 a.m. to 5:00 p.m., on-peak 5:01 p.m. to 10:00 p.m.); Summer is a two-period schedule (off-peak 10:01 p.m. to 10:00 a.m., on-peak 10:00 a.m. to 10:00 p.m.).

Energy Division notes that although Liberty's winter on-peak window (5:01 p.m. to 10:00 p.m.) does not overlap with midday solar production, its summer on-peak window (10:00 a.m. to 10:00 p.m.) fully contains the solar peak and its winter mid-peak window (7:01 a.m. to 5:00 p.m.) captures most of the remainder. Solar exports are therefore credited at a slight premium to the annual average retail rate, approximately 49.1 cents/kWh, even though the grid value of that energy is far lower. Export compensation must therefore be set relative to avoided costs, not retail rates, to be cost-effective.

Figure 1. Average-day Tahoe-basin solar production against Liberty TOU D-1 peak-rate windows (AL 295-E). Roughly half of annual output falls in summer on-peak and most of the remainder in winter mid-peak.



B. Export Compensation: Staff Recommendation and Alternative

Staff analyzed two approaches for setting Liberty NBT export compensation. Both are grounded in avoided costs rather than retail rates. Staff recommends Option B-1 (fixed percentage of TOU rate) and presents Option B-2 (Net Surplus Compensation rate) as an alternative.

B-1. Staff Recommendation: Floating Percentage of Applicable TOU Rate (All Customer Classes)

The Commission adopts a single export compensation rate for all Liberty NBT customer classes, expressed as a floating percentage of the applicable TOU rate and set each year to equal Liberty's avoided cost. At current rates that percentage is approximately 10%:

- Schedule TOU D-1 (residential): approximately 10% of the 49.1 cents/kWh solar-weighted average = 4.94 cents/kWh, equal to the Liberty-specific avoided cost constructed from the GRC revenue-requirement record.
- Schedule TOU A-1 (non-residential): the A-1 solar-weighted TOU rate is approximately 47.5 cents/kWh, comparable to Schedule TOU D-1, so the same floating percentage (approximately 10%) yields an export credit at the 4.94 cents/kWh avoided cost. This is a marked reduction from the roughly 9.6x overcompensation A-1 customers receive under Liberty's current NEM 1.0.

See Appendix B for information about how the 10% figure was calculated.

B-2. Alternative: Net Surplus Compensation Rate

As an alternative to the fixed or floating percentage, the Commission could direct Liberty to compensate exports at an annual average avoided cost rate for Liberty's applicable balancing authority area, updated annually by Tier 1 advice letter. This is the Net Surplus Compensation (NSC) approach used by BVES and the large IOUs under PU Code Section 2827.10 and D.11-06-016,⁸ and it is the only existing California framework for setting avoided-cost-based export rates on an annual basis.

Liberty would calculate the NSC rate using the following sources, in order of preference:

- The annual average wholesale day-ahead energy price at the applicable WECC trading hub for Liberty's balancing authority area, calculated and reported in Liberty's annual Tier 1 advice letter filing.
- The avoided cost rate established by Liberty in its GRC Chapter 9 marginal cost study, updated each GRC cycle.

The NSC approach has two advantages: it tracks actual avoided energy costs in the applicable market rather than approximating them via a proxy percentage, and it is consistent with the framework the Commission has already established for California utilities. It also has two disadvantages. First, at current western US day-ahead prices, the NSC rate would likely fall in the range of 2.5 to 5 cents/kWh, which brackets only the energy portion of the GRC MCOS-derived recommendation of 4.94 cents/kWh for D-1, because it captures energy value only and omits the GHG, generation capacity, and distribution components included in the Liberty-specific avoided cost calculation. Second, the NSC approach requires Liberty to collect and file annual market price data it does not currently track, creating administrative complexity without a commensurate gain in accuracy given the absence of an adopted ACC methodology for Liberty's balancing authority area.

Table 3 compares the two approaches at current rate levels.

Table 3. Comparison of Proposed Export Compensation Approaches for Liberty NBT.

	Option B-1 (25% of applicable TOU rate)	Option B-2 (NSC rate)	Notes
Export rate, TOU D-1 residential	~4.94 ¢/kWh (~10% × 49.1¢)	~2.55–5.00 ¢/kWh (est. western US market)	Option B-1 reflects GRC MCOS avoided cost; B-2 reflects energy only
Export rate, TOU A-1 commercial	~avoided cost (~10% × A-1 rate)	~2.55–5.00 ¢/kWh (same source)	Floating %; A-1 credit near 4.94¢ avoided cost
Match to GRC MCOS avoided cost (4.94¢)	D-1: ~1.0x (4.94 ÷ 4.94); A-1: near 1.0x	0.33–0.65x (energy only; below full avoided cost)	Option B-1 brackets avoided cost; Option B-2 underpays substantially

⁸ D.11-06-016, Decision Implementing AB 920 Net Surplus Compensation (June 2011).
<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D1106016>

	Option B-1 (25% of applicable TOU rate)	Option B-2 (NSC rate)	Notes
Update frequency	Automatic (tracks retail rate changes each GRC)	Annual Tier 1 AL	
Includes GHG and capacity value	Yes (embedded in GRC MCOS calculation)	No (wholesale energy price only)	Material given NV Energy gas-dominant marginal resource
Data Liberty currently has	Yes (own TOU rates; GRC MCOS already filed)	No (requires BAA market price data)	Options B-2 requires new annual data collection process
Staff recommendation	Recommended	Alternative	

C. Interconnection Fee

The Commission adopts the following interconnection fee methodology: Liberty will charge a one-time fee equal to its documented actual average per-customer interconnection cost, consistent with [D.22-12-056](#) Ordering Paragraph 6. Liberty will calculate the initial fee and file the result in its Tier 2 implementation advice letter. Annual updates will be filed by Tier 1 advice letter no later than 19 September of each year beginning September 2027, each of which will also identify the highest-differential active TOU import rate in effect at the time of filing.

Liberty will charge a one-time interconnection fee based on its documented actual average per-customer interconnection cost, consistent with the interconnection cost principles applicable to the large IOUs. Liberty will calculate the initial fee and propose it in its Tier 2 implementation advice letter. Thereafter, Liberty shall report its actual interconnection costs annually to Energy Division. If the annual cost information demonstrates that a modification to the approved interconnection fee is warranted, Liberty may submit a Tier 2 advice letter requesting Commission approval to modify the fee. The annual reporting requirement does not, by itself, require an annual modification of the interconnection fee.

D. Billing, True-Up, and Netting Interval

The Liberty NBT uses a structure with no netting interval, consistent with the large IOU Net Billing Tariff. All electricity exported to the grid is compensated at the export rate adopted in Section B, credited as a separate line item from consumption charges. There is no monthly netting of exports against imports. Billing occurs monthly.

Liberty NBT customers are subject to an annual true-up period based on each customer's interconnection anniversary date. At true-up, any annual net surplus exports, where annual export credits in a 12-month period exceed annual consumption charges, are settled at the Net Surplus Compensation rate established in Section G. This replaces the annual netting interval under Liberty's

current Schedule NEM, under which exports offset imports at full retail rate over a 12-month period. Liberty's Tier 2 implementation advice letter will include the revised billing and true-up methodology.

E. Non-Bypassable Charges

The Liberty NBT will exclude non-bypassable charges (NBCs) analogous to those adopted in D.22-12-056 for large investor-owned utility NBT customers. A separate NBC mechanism is largely unnecessary because Liberty's Base Services Charge (BSC), a fixed monthly charge that all customers pay regardless of consumption level (currently \$31.70 per month for non-CARE customers), already collects some fixed grid costs from Liberty NBT customers, including those who substantially offset their consumption through solar. Layering a NBC on top of the BSC without a Liberty-specific cost analysis would risk double-collection of costs the BSC already recovers.

Simplicity independently supports this design, on both sides of the meter. The large IOU NBC framework was implemented on enterprise billing platforms capable of tracking and reconciling multiple charge categories per account; Liberty is a small utility serving fewer than 60,000 customers, and its billing operations are not comparable in scale or capability. On the customer side, D.23-04-040 Principle 7 requires that customers be able to understand their rates, and a separate NBC line item, alongside consumption charges, export credits, the annual true-up, and the NSC payment, adds complexity for a population already navigating a new tariff structure. The no-NBC design recovers fixed costs through the existing BSC, produces a bill customers can verify, and simplifies the tariff for a utility with limited billing infrastructure, without impugning the NBC framework D.22-12-056 adopted for the large IOUs.

F. Installation Size Limit

In all cases, the generating facility must satisfy both the 1 MW maximum capacity limit and the 100 percent annual-load sizing limit. Liberty's Tier 2 implementation advice letter shall specify the methodology and documentation used to determine a customer's annual electrical consumption and demonstrate compliance with the 100 percent annual-load sizing limit.

G. Net Surplus Compensation

Under PU Code Section 2827.10, every electric utility must pay Net Surplus Compensation (NSC) to eligible customer-generators who produce more electricity in a 12-month period than they consume. Liberty NBT customers are eligible for NSC at annual true-up. The NSC rate will equal the annual average wholesale day-ahead energy price at the applicable WECC trading hub for Liberty's balancing authority area. Liberty will calculate and file this rate annually in its Tier 1 advice letter, using the same NSC proxy methodology as BVES under AL 513-E⁹ (annual average SCE Net Surplus Compensation Rate as a proxy if a BAA-specific rate cannot be calculated). The NSC rate is energy-only and does not include GHG, generation capacity, or distribution components.

H. NEM 1.0 Migration; No Legacy Period

Liberty's Schedule NEM tariff closes to new interconnections on the Commission decision issuance date. All existing Liberty Schedule NEM customers migrate to the Liberty NBT at the customer's first

⁹ BVES Advice Letter 513-E, Updating Net Surplus Compensation Rate (effective May 2025). Available at BVES tariff schedules. <https://www.bvesinc.com/customer-service/rates-regulations/general-rate-schedules>

true-up occurring after 1 January 2027. Migration cannot occur before the Liberty NBT tariff becomes effective upon Energy Division disposition of Liberty's Tier 2 implementation advice letter.

No legacy period is warranted. The legal and policy basis for this conclusion rests on four independent grounds.

First, PU Code Section 2827(c)(1) governs the NEM obligation of every electric utility, including SMJUs. It requires each utility to offer NEM on a first-come-first-served basis until the program capacity limit is reached, at which point existing customers retain the right to continue service "for a length of time to be determined by the commission." The statute imposes no specific legacy period and requires no payback-period analysis for small utilities. In contrast, PU Code Section 2827.1, which produced the 20-year legacy period for large IOU NEM customers, applies only to "large electrical corporations," defined as utilities with more than 100,000 service connections (PU Code Section 2827(b)(5)). Liberty, with approximately 30,000 service connections, is not a large electrical corporation. PU Code Section 2827.1 does not apply to Liberty's NEM customers. The Commission is therefore determining the transition period under the broader discretion of PU Code Section 2827(c)(1), which imposes no minimum duration and no payback-period floor.

Second, no CPUC proceeding has ever established a legacy period for Liberty NEM customers under PU Code Section 2827(c)(1). D.14-03-041¹⁰ established the 20-year legacy period for large IOU NEM 1.0 customers pursuant to PU Code Section 2827.1(b)(6), which directed the Commission to determine a transition period by 31 March 2014, considering "a reasonable expected payback period." No analogous determination was ever made for Liberty under PU Code Section 2827(c)(1). Liberty NEM customers have never been subject to the non-bypassable charges, mandatory TOU enrollment requirements, or cost-shift mitigation obligations that added complexity to large IOU NEM 2.0 transition. Therefore, the circumstances that justified a lengthy legacy period for large IOU customers are absent here. Further, a single tariff for all behind-the-meter customer generation, provides simplicity and lower administrative costs that are more reasonable for the size SMJUs.

Third, the Commission's finding in D.22-12-056¹¹ that NEM customers have no vested right to specific compensation rates applies with equal or greater force at Liberty, where no legacy commitment was ever established. The Liberty NBT provides a reasonable successor tariff under which customers retain full rights to operate their generating facilities and receive compensation based on avoided costs. The change in compensation rate does not constitute a regulatory taking under *Duquesne Light Co. v. Barasch*, 488 US 299 (1989)¹² because customers retain the legal right to operate their solar generating facilities under the new tariff terms.

Fourth, the magnitude of the cost shift counsels against any legacy period. At a 3.9x overcompensation ratio, each year of continued Liberty NEM operation transfers approximately \$80 to \$120 of unjustified subsidy per NEM account from non-participant ratepayers, a population that skews lower-income and has absorbed 121% rate increases since 2020. A legacy period of several years would perpetuate a

¹⁰ D.14-03-041, Decision on NEM 1.0 Legacy Period and Transition to NEM 2.0 (March 2014).

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D1403041>

¹¹ D.22-12-056, Decision Adopting Net Billing Tariff as Successor to NEM 2.0 (December 2022).

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF>

¹² *Duquesne Light Co. v. Barasch*, 488 US 299 (1989). <https://www.govinfo.gov/app/details/USREPORTS-488/USREPORTS-488-299>

cross-subsidy that PU Code Section 2827(c)(1) gives the Commission full discretion to terminate. The Commission exercises that discretion here to direct immediate migration, consistent with its rate design authority under PU Code Sections 451 and 728.

Liberty must issue written notice to all affected NEM customers within 30 days of the Commission decision issuance date. Consistent with D.23-04-040¹³ Principle 10, which requires that transitions to new rate structures include customer education and outreach and minimize bill impact, the notice must: (1) explain the Liberty NBT net billing structure, monthly billing cycle, annual true-up, and export compensation rate; (2) state the customer's interconnection anniversary date and the expected migration date; (3) provide an estimated annual bill impact based on the customer's most recent 12 months of consumption and export data; (4) describe the Net Surplus Compensation rate and how Liberty will calculate and file it annually; and (5) direct customers to Liberty's dedicated Liberty NBT transition webpage. Liberty will publish a plain-language FAQ and rate comparison tool on its website concurrent with the notice mailing.

I. Billing System Updates

Liberty must complete all billing system updates necessary to operationalize the Liberty NBT, including the net billing structure, monthly billing cycle, annual true-up, and NSC calculation, within six months of the Commission decision issuance date. Liberty will file a compliance report with Energy Division upon completion.

IV. PROPOSED BVES AND PACIFICORP TARIFF MODIFICATIONS

A. Mandatory TOU Import Rate

PacifiCorp Schedule NB-136 and BVES Schedule DGS customers will be mandated to take service on the highest differential TOU rate available to each customer class. PacifiCorp NB-136 customers will take service on Schedule DT (residential) or AT-29 (non-residential). BVES DGS non-residential customers will take service on Schedule A-4 TOU (demand up to 500 kW) or Schedule A-5 TOU (demand above 500 kW). BVES does not currently offer a residential TOU rate; however, if and when a residential TOU rate is established for BVES customers, DGS customers will be mandated to take service on it.

B. Annual Interconnection Fee Advice Letter Process

BVES and PacifiCorp will utilize the same interconnection fee methodology: a one-time fee equal to documented actual average per-customer interconnection cost, consistent with D.22-12-056 Ordering Paragraph 6. Both utilities will calculate the initial fee and file the result in their Tier 2 implementation advice letters within 60 days of the Commission decision issuance date. Annual Tier 1 updates will be filed no later than 19 September of each year beginning September 2027, identifying the highest-differential active TOU import rate in effect at the time of filing. For expediency, BVES will additionally include its annual DGS export compensation update in the same filing per D.20-01-008 Ordering Paragraph 2 (see Section VII for more information).

C. Billing, True-Up, and Netting Interval

¹³ D.23-04-040, Decision Adopting Rate Design Principles (2023).
<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D2304040>

BVES Schedule DGS and PacifiCorp Schedule NB-136 both operate on a net billing basis with no netting interval, consistent with the large IOU NBT. No changes to the existing billing structure are required for these utilities under this Staff Proposal. For reference: BVES DGS uses monthly billing and monthly settlement with no annual true-up rollover period; PacifiCorp NB-136 uses monthly billing with an annual true-up in March for most customers. Both structures require no modification.

D. Non-Bypassable Charges

BVES Schedule DGS and PacifiCorp Schedule NB-136 will not include non-bypassable charges. As described in Section III.E, a separate NBC mechanism is unwarranted where an existing fixed monthly charge already recovers fixed grid costs. BVES and PacifiCorp both collect Base Services Charges from all customers, including DGS and NB-136 enrollees (\$23.22 and \$26.34 per month for non-CARE single-family customers, respectively), that serve a comparable cost-recovery function. No separate NBC mechanism is warranted for these tariffs.

The billing and metering infrastructure rationale described in Section III.E also applies to BVES and PacifiCorp. Similar to Liberty, both utilities serve small, dispersed customer populations in mountainous service territories and operate billing systems that, like Liberty's, are not equipped to separately track and reconcile multiple NBC charge categories, integrate NBC calculation with CARE and FERA program discounts, maintain separate regulatory accounts for NBC revenue streams, and file NBC compliance reports with Energy Division. BVES Schedule DGS has an aggregate program enrollment cap of 2 megawatts under D.20-01-008,¹⁴ meaning the total number of DGS customers subject to any NBC mechanism is very small. PacifiCorp's California service territory is rural and geographically isolated, with metering and billing infrastructure similar in vintage and capability to Liberty's. In both cases, the cost of implementing a compliant NBC billing mechanism would be disproportionate to the annual NBC revenue recoverable from the small number of enrolled customers.

E. Installation Size Limit

In all cases, the generating facility must satisfy both the 1 MW maximum capacity limit and the 100 percent annual-load sizing limit. BVES and PacifiCorp's respective Tier 2 implementation advice letters shall specify the methodology and documentation used to determine a customer's annual electrical consumption and demonstrate compliance with the 100 percent annual-load sizing limit.

BVES Schedule DGS remains separately subject to the existing 1 MW aggregate program capacity cap established in D.20-01-008.

F. Export Compensation: Current BVES and PacifiCorp Rates

BVES Schedule DGS export compensation is 2.55 cents/kWh for 2025, per AL 513-E,¹⁵ derived from the annual average SCE Net Surplus Compensation Rate as a proxy for BVES's avoided energy cost. This

¹⁴ D.20-01-008, Decision Approving Bear Valley Electric Service Distributed Generation Service Tariff (2020). <https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D2001008>

¹⁵ BVES Advice Letter 513-E, Updating Net Surplus Compensation Rate (effective May 2025). Available at BVES tariff schedules. <https://www.bvesinc.com/customer-service/rates-regulations/general-rate-schedules>

rate is updated annually through the advice letter process established in D.20-01-008¹⁶ Ordering Paragraph 2. The overcompensation ratio of approximately 3.5x cited in Table 1 uses this current rate. No change to the BVES DGS export compensation methodology is proposed in this Staff Proposal; the annual NSCR-based update process continues.

PacifiCorp Schedule NB-136 export rates are: on-peak 12.352 cents/kWh, off-peak 9.568 cents/kWh, and flat non-TOU rate 10.065 cents/kWh. These are fixed rates established in D.20-01-007¹⁷ as PacifiCorp's Commission-approved avoided cost rates for its California customers.

D.11-06-016 established California's Net Surplus Compensation framework under PU Code Section 2827.10, resolving the consolidated NSC applications of the three large IOUs, PacifiCorp, and Liberty's predecessor Sierra Pacific Power Company, and confirmed that the NSC rate must not exceed the utility's full avoided costs.

PacifiCorp's NB-136 net billing structure satisfies both PURPA Section 210 and PU Code Section 2827.10 through its ongoing export crediting mechanism. Every kilowatt-hour exported to the grid is credited at the Commission-approved avoided cost rate at the time of export: on-peak 12.352 cents/kWh or off-peak 9.568 cents/kWh. Net surplus in any monthly billing period is settled at this avoided cost rate. Because PacifiCorp continuously purchases and compensates net exports at the avoided cost rate on a monthly basis, NB-136 customers receive the economic equivalent of NSC on an ongoing basis rather than through a separate annual true-up. There is no net surplus that accumulates uncompensated; the PURPA purchase obligation is discharged at each monthly billing cycle. No separate annual NSC mechanism is required because the net billing structure already provides continuous avoided-cost compensation that exceeds the minimum required by PURPA and PU Code Section 2827.10.

G. Authority to Modify Legacy Period Provisions in DGS and NB-136

Both existing BVES and PacifiCorp net billing tariffs contain explicit legacy period language that predates this proceeding. BVES Schedule DGS¹⁸ states that eligible customers "continue receiving service on this Schedule for a period of 20 years from the date of interconnection for the Facility." PacifiCorp Schedule NB-136¹⁹ states that "Customer sites that receive service under this schedule may remain on Net Billing Service for at least 20 years following the date of interconnection." Energy Division addresses these provisions here because the TOU import requirement adopted in Section IV.A modifies the terms of service for existing DGS and NB-136 customers within their legacy periods, and parties should have the opportunity to comment on the Commission's authority to do so.

Three grounds support the Commission's authority to modify these tariff terms notwithstanding the legacy period language.

16 D.20-01-008, Decision Approving Bear Valley Electric Service Distributed Generation Service Tariff (2020).

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D2001008>

17 D.20-01-007, Decision Approving PacifiCorp Net Billing Tariff Schedule NB-136 (2020).

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D2001007>

18 BVES Schedule DGS (Distributed Generation Service Program), current tariff sheet (AL 489-E, Decision No. D.20-01-008, effective May 2024). <https://www.bvesinc.com/assets/documents/rates/sch-dgs-2025pdf.pdf>

19 PacifiCorp Schedule NB-136 (Net Billing Service), current tariff sheet (AL 728-E, effective 12 January 2024).

https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/california/rates/NB-136_Net_Billing_Service.pdf

First, the legacy period provisions are utility-proposed tariff terms approved under the Commission's general ratemaking authority, not statutory entitlements. Neither BVES nor PacifiCorp was required by statute to include a legacy period in its net billing tariff. PU Code Section 2827.1, which mandates a legacy period, applies only to large electrical corporations. D.20-01-008 and D.20-01-007 approved utility-proposed program terms as part of general ratemaking; they were not final determinations of tariff structure insulated from future Commission review. The R.25-01-005 OIR expressly opened these tariffs for comprehensive review. Under PU Code Section 451, the Commission has an ongoing obligation to ensure rates are just and reasonable, which necessarily includes authority to modify utility-proposed tariff provisions that have become inconsistent with that standard.

Second, the legacy period language guarantees access to the program, not frozen program terms. The BVES DGS legacy provision says customers "continue receiving service on this Schedule", it guarantees continued eligibility for the program, not immunity from changes to the schedule's terms. PacifiCorp's NB-136 language is identical in effect: it commits to "Net Billing Service" as a category, not to any specific export compensation rate or import rate structure. The Commission routinely modifies the terms of tariff schedules during the period in which customers have a right to remain enrolled, including through mandatory TOU rate transitions. The TOU import requirement adopted in Section IV.A is a change to schedule terms, not a termination of the customer's right to remain enrolled. Customers retain full access to DGS and NB-136 under the modified terms.

Third, the Commission's modification of these tariff provisions does not constitute a regulatory taking. Under *Duquesne Light Co. v. Barasch*, 488 US 299 (1989),²⁰ a change in utility rate structure is not a taking so long as the regulated entity retains a reasonable opportunity to earn a return. BVES and PacifiCorp DGS/NB-136 customers retain full access to the programs and full compensation for their exports at the tariff-specified rates; only the import rate structure changes to require TOU enrollment. The PacifiCorp NB-136 "at least 20 years" language is particularly notable: it imposes no upper bound on the Commission's ability to modify program terms, and the Commission has never construed utility-proposed tariff language as binding the Commission against modification in a subsequent ratemaking proceeding.

H. NEM 1.0 Migration

To improve equity and support the electrification efforts outlined in this Staff Proposal, any remaining BVES Schedule NEM-S and NEM-L customers and PacifiCorp Schedule NEM-35 legacy customers will migrate to the applicable current net billing tariff (DGS or NB-136) at the customer's first true-up occurring after 1 January 2027. BVES and PacifiCorp must issue written notice to all affected customers within 30 days of the Commission decision issuance date, and a second notice at least 60 days before the customer's migration date.

The case for prompt migration is the cost shift. Retail-rate export crediting pays legacy customers roughly ten times avoided cost, shifting approximately \$2,400 per participating customer per year onto non-participants (Section II). The transfer runs in the regressive direction documented in Section II: solar adopters skew toward higher-income homeowners with the capital to install a system, while the

²⁰ *Duquesne Light Co. v. Barasch*, 488 US 299 (1989). <https://www.govinfo.gov/content/pkg/USREPORTS-488/pdf/USREPORTS-488-299.pdf>

non-participants who fund the subsidy include renters and lower-income households who are often unable to adopt. Both legacy schedules closed to new enrollment under D.20-01-008 and D.20-01-007, so these systems are all more than five years old and have substantially recovered their capital costs; every additional year of legacy treatment compounds the transfer while protecting no remaining investment-backed expectation and inducing no new solar development.

The same cost shift works against electrification. The subsidy is recovered through inflated volumetric rates paid by every customer, and in winter-peaking mountain territories, high volumetric rates are precisely what deters the heat pump and electric vehicle adoption. A household weighing a heat pump against propane faces an electricity price that contains the embedded cost of legacy solar compensation rates; ending that markup improves electrification economics for all customers, including the migrating customers themselves, whose self-consumption value and interconnection are unaffected. Migration at the first true-up after 1 January 2027 gives every affected customer a full billing cycle of notice while completing the transition within calendar year 2027, is prospective only, consistent with the Commission's authority under PU Code Sections 451, 728, and 701 (see also *Duquesne Light Co. v. Barasch*, 488 US 299 (1989)), and consolidates each utility to a single customer generation tariff, ending parallel administration of the paper-based legacy schedules documented in Section II.

I. Billing System Updates

BVES and PacifiCorp must complete all billing system updates necessary to implement the TOU import rate requirement within six months of the Commission decision issuance date and will file compliance reports with Energy Division upon completion.

V. IMPLEMENTATION TIMELINE

Table 4 sets out the implementation schedule following the Commission decision. "D" denotes the Commission final decision issuance date.

Table 4. Proposed Implementation Schedule.

Date / Timing	Action	Responsible Party
D	Commission decision issued.	Commission
D + 30 days	SMJUs coordinate with Energy Division on the timing, content, and method of customer notification and provide written notice to all NEM 1.0 customers at all three utilities (90-day advance notice window)	All SMJUs / Energy Division
D + 60 days	Consolidated Tier 2 ALs (one per utility): closure of NEM 1.0 tariff sheets; Liberty NBT implementation; BVES DGS and PacifiCorp NB-136 TOU modifications; initial interconnection fees	All SMJUs / Energy Division

Date / Timing	Action	Responsible Party
D + 180 days	Billing system updates complete; compliance reports filed with Energy Division	All SMJUs
First true-up after 1 January 2027 (completing during 2027)	Remaining NEM 1.0 customers at all three utilities migrate to the applicable net billing tariff (Liberty NBT, DGS, or NB-136); no legacy period attaches	All SMJUs
19 September annually (first: September 2027)	Annual Tier 1 ALs: interconnection fee updates; highest-differential TOU rate identification; BVES DGS export compensation update per D.20-01-008 OP 2	All SMJUs
2030	Energy Division program evaluation: per-customer cost shift, export compensation alignment with utility-specific avoided costs, and enrollment vs. pre-reform baselines	Energy Division

VI. CONSOLIDATED ADVICE LETTER REQUIREMENTS

To minimize filing burden and Energy Division review workload, all compliance obligations are consolidated into a single Tier 2 implementation advice letter per utility and a single annual Tier 1 filing per utility: six filings in total. Consolidation is warranted in light of the manual, paper-based interconnection and tariff records documented in Section II, which make each additional filing materially burdensome for utilities of this size. Table 5 lists the consolidated advice letters required under this Staff Proposal.

Table 5. Consolidated Advice Letter Requirements.

Filing Deadline	Tier	Advice Letter
D + 60 days	Tier 2	Liberty: consolidated implementation AL: closure of Schedule NEM to new enrollment; closure of Schedule DE to new enrollment and transition of existing enrollees; Liberty NBT implementation, TOU import rate criterion (Schedule TOU D-1/A-1, highest differential), export compensation rate (floating percentage of the applicable TOU rate, approximately 10% at current rates, as adopted in decision), initial interconnection fee (documented actual cost per adopted methodology); 1 MW maximum generating-facility size; 100 percent annual-load sizing limit; and the methodology and

Filing Deadline	Tier	Advice Letter
		documentation used to determine a customer's annual electrical consumption and demonstrate compliance with the 100 percent annual-load sizing limit.
D + 60 days	Tier 2	BVES: consolidated implementation AL: closure of Schedules NEM-S and NEM-L to new enrollment; closure of Schedule DE to new enrollment and transition of existing enrollees; DGS modification to require Schedule A-4/A-5 TOU import for non-residential customers, and initial interconnection fee per methodology adopted in decision; 1 MW maximum generating-facility size; 100 percent annual-load sizing limit; and the methodology and documentation used to determine a customer's annual electrical consumption and demonstrate compliance with the 100 percent annual-load sizing limit.
D + 60 days	Tier 2	PacifiCorp: consolidated implementation AL: closure of Schedule NEM-35 to new enrollment; closure of Schedule DE-12 to new enrollment and transition of existing enrollees; NB-136 modification to require Schedule DT/AT-29 import, and initial interconnection fee per methodology adopted in decision; 1 MW maximum generating-facility size; 100 percent annual-load sizing limit; and the methodology and documentation used to determine a customer's annual electrical consumption and demonstrate compliance with the 100 percent annual-load sizing limit.
19 September annually	Tier 1	All SMJUs (one filing per utility): Annual net billing tariff report per D.22-12-056 OP 6 (highest-differential TOU rate identification; Liberty floating-percentage recalculation and implied cents/kWh value; enrollment; interconnection fee update). BVES also includes DGS export compensation update per D.20-01-008 OP 2.

APPENDIX A – Abbreviations and Summary of Findings

Table A-1. Acronyms and Abbreviations.

ACC	Avoided Cost Calculator (CPUC, adopted per Resolution E-5328)
AL	Advice Letter
ALJ	Administrative Law Judge
BAA	Balancing Authority Area
BSC	Base Services Charge (fixed monthly charge; the SMJU equivalent of the large-IOU AB 205 Base Services Charge)
BVES	Bear Valley Electric Service
CAISO	California Independent System Operator
CARE	California Alternate Rates for Energy
D.	Decision (CPUC)
DGS	Distributed Generation Service (BVES customer generation program, Schedule DGS)
ED	Energy Division (CPUC)
FERC	Federal Energy Regulatory Commission
FERA	Family Electric Rate Assistance
GHG	Greenhouse Gas
GO	General Order (CPUC)
GRC	General Rate Case
IOU	Investor-Owned Utility
kWh	Kilowatt-hour
Liberty NBT	Liberty Net Billing Tariff (proposed in this Staff Proposal)
NB-136	PacifiCorp Schedule NB-136 (Net Billing Service)
NBC	Non-Bypassable Charge
NBT	Net Billing Tariff
NEM	Net Energy Metering
NP15	Northern California pricing node (CAISO wholesale market hub)

NSCR	Net Surplus Compensation Rate
NSC	Net Surplus Compensation
OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
PTO	Permission to Operate
PU Code	California Public Utilities Code
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility (under PURPA)
R.	Rulemaking (CPUC)
RIM	Ratepayer Impact Measure (cost-effectiveness test)
SMJU	Small Multi-Jurisdictional Utility (Liberty, BVES, PacifiCorp)
TOU	Time-of-Use
TRC	Total Resource Cost (cost-effectiveness test)
WECC	Western Electricity Coordinating Council

Table A-2. Summary of Key Quantitative Findings.

Finding	Value
Liberty solar-weighted TOU D-1 rate (residential)	49.1 ¢/kWh
Liberty solar-weighted avoided cost (A.24-09-010 GRC marginal cost study)	4.94 ¢/kWh (constructed from Liberty's GRC revenue requirement; Steps 1–10 in Appendix B)
Liberty overcompensation ratio, residential (D-1)	9.9x (49.1/4.94)
Proposed Liberty NBT export compensation	Floating % of applicable TOU rate (~10%; = 4.94 ¢/kWh on D-1)
Annual cost shift per participating customer (representative Liberty residential)	\$940/yr (proposed NBT) vs. \$2,385/yr (current NEM)

APPENDIX B – Export Compensation Percentage Calculations

To quantify participant impacts, Energy Division modeled a representative Liberty residential customer using 5,400 kWh per year (450 kWh per month) with an evening-peaked, winter-weighted load shape and a 2.6 kW installation producing 5,400 kWh per year (100% of annual load) on a clear-sky Tahoe-basin profile, of which approximately 40% is self-consumed and 60% is exported. The pre-solar bill is approximately \$2,910 per year (\$242 per month), including the \$31.70 monthly BSC. Under the proposed Liberty NBT the post-solar bill is approximately \$1,700 per year (\$142 per month), a saving of approximately \$1,210 per year: roughly \$1,050 from avoided retail purchases through self-consumption and roughly \$160 from export credits at avoided cost.

Under the current retail-rate NEM tariff the same customer pays approximately \$260 per year, a saving of approximately \$2,650 per year. Because the avoided-cost value of the system's entire output is only approximately \$270 per year, the current tariff shifts approximately \$2,400 per year per participating customer to non-participants, while the proposed Liberty NBT reduces that shift to approximately \$940 per year, essentially all of which is the fixed-cost-recovery effect of self-consumption discussed in Section II rather than export overcompensation.

Figure B-1. Annual bills for the representative Liberty residential customer. The dashed benchmark is the pre-solar bill less the avoided-cost value of the system's output; the distance below it is the cost shift to non-participants.



The floating percentage is calibrated to the dominant residential customer class, for which it equals the Liberty-specific avoided cost of 4.94 cents/kWh. A uniform percentage for all customer classes eliminates the need for class-specific tracking in Liberty's billing system, reduces the risk of billing errors at a small utility with limited billing infrastructure, and produces a simpler tariff that customers of both classes can verify from the published TOU rate schedule alone. The administrative simplicity benefit outweighs the marginal imprecision relative to class-specific rates.

The recommended rates are supported by the following lines of evidence, all drawn from Liberty-specific or directly comparable data sources:

- Liberty operates in the same balancing authority area as NV Energy's northern Nevada service territory and purchases power through an NV Energy Energy Supply Agreement. The Liberty-specific avoided cost of 4.94 cents/kWh is approximately 10% of the 49.1 cents/kWh solar-weighted TOU D-1 rate, implying an overcompensation ratio near 9.9x under the current retail-rate NEM tariff. This exceeds the 4.5x that the Nevada PUC found and is directionally consistent evidence of substantial overcompensation, underpinning the floating-percentage recommendation.
- Liberty Test Year 2025 GRC (A.24-09-010²¹), primary calculation basis. All inputs are drawn exclusively from Liberty's own GRC record. The avoided cost calculation follows ten steps, each documented below with its data source and arithmetic.

Step 1. Total system energy (kWh denominator). Liberty's fuel and purchased power expense for TY 2025 is \$44,172,000.²² Liberty purchases nearly all electricity from NV Energy under a bilateral Energy Supply Agreement (ESA) that includes both a variable energy charge (\$/kWh) and a fixed capacity demand charge (\$/kW-month). The combined all-in effective unit cost under the ESA is approximately \$0.10/kWh based on the ESA structure documented in Liberty's ECAC filings. Total system energy: \$44,172,000 ÷ \$0.10/kWh = 441,720,000 kWh, rounded to 442 million kWh. Liberty's filed average residential winter monthly usage is 714 kWh. At 51,551 customers, weighted-average usage of 714 kWh/month implies approximately 442 million kWh annually.

Step 2. MCOS inputs. D.20-08-030²³ Ordering Paragraph 12 directed Liberty to file a Marginal Cost of Service Study based on its own system data in its next GRC, rather than relying on NV Energy system averages. Liberty complied in Exhibit Liberty-09.²⁴ Cal Advocates independently reviewed these figures and filed its own MCOS analysis.²⁵ All parties stipulated to the admission of both exhibits into the evidentiary record. Energy Division uses Cal Advocates' figures, which are independently reviewed and modestly conservative relative to Liberty's own estimates.

*Table B-1. Liberty MCOS Inputs.*²⁶ *Customer cost components are excluded from export compensation: the customer remains connected and those fixed costs continue regardless of export activity.*

21 A.24-09-010, Liberty Utilities (CalPeco Electric) Application for Test Year 2025 General Rate Case (filed September 2024).

https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A2409010

22 Liberty Utilities Exhibit Liberty-06, Witness Manasa Rao, A.24-09-010 (TY 2025 GRC), Chapter 6: Revenue Requirement. Table I-1, line Fuel & Purchased Power (\$44,172,000 for TY 2025), filed 20 September 2024.

<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M541/K331/541331234.PDF>

23 D.20-08-030, Decision Approving All-Party Settlement Agreement on Liberty Utilities (CalPeco Electric) LLC TY 2022 General Rate Case (August 2020). Ordering Paragraph 12 directed Liberty to file, in its next GRC, an updated Marginal Cost of Service Study based on its own system distribution network and not use NV Energy's marginal cost data.

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=D2008030>

24 Liberty Utilities Exhibit Liberty-09, Witness Timothy Lyons, A.24-09-010 (TY 2025 GRC), Chapter 9: Marginal Costs and Rate Design (including Liberty's MCOS and Rate Design Model workpapers), filed 20 September 2024. Cal Advocates CA-04 independently reviewed and accepted these figures with minor adjustments.

https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A2409010

25 Cal Advocates (Public Advocates Office) Exhibit CA-04, Witness Maricela Sierra, A.24-09-010 (Liberty Utilities TY 2025 GRC), Section V: Marginal Costs and Rate Design, Table 4-3 (Marginal Costs of Service Summary), filed 2 July 2025.

<https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2409010/8297/571368878.pdf>

26 Cal Advocates (Public Advocates Office) Exhibit CA-04, Witness Maricela Sierra, A.24-09-010 (Liberty Utilities TY 2025 GRC), Section V: Marginal Costs and Rate Design, Table 4-3 (Marginal Costs of Service Summary), filed 2 July 2025.

<https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2409010/8297/571368878.pdf>

MCOS Component	Total (\$, TY 2025)	Source
Marginal Generation (Energy)	\$14,652,945	CA-04, Table 4-3
Marginal Generation (Capacity)	\$10,297,111	CA-04, Table 4-3
Marginal Distribution (TOU)	\$20,576,733	CA-04, Table 4-3
Marginal Distribution (Non-TOU)	\$25,316,112	CA-04, Table 4-3
Marginal Customer (Common)	\$4,801,427	CA-04, Table 4-3, excluded from export calc
Marginal Customer (Specific)	\$6,339,380	CA-04, Table 4-3, excluded from export calc
Total MCOS (Cal Advocates)	\$81,983,709	CA-04, Table 4-3

Step 3. Raw per-kWh conversion. Each generation and distribution component is divided by 442,000,000 kWh:

Table B-2. Raw Per-kWh Values Before Solar Production Weighting.

Component	Dollar Total	÷ 442m kWh	Raw ¢/kWh
Marginal Generation (Energy)	\$14,652,945	÷ 442,000,000	3.313¢
Marginal Generation (Capacity)	\$10,297,111	÷ 442,000,000	2.330¢
Marginal Distribution (TOU)	\$20,576,733	÷ 442,000,000	4.655¢
Marginal Distribution (Non-TOU)	\$25,316,112	÷ 442,000,000	5.727¢

Step 4. Solar weighting: energy component. Liberty purchases nearly all energy under a bilateral Energy Supply Agreement with NV Energy at an effectively flat all-in unit cost, and no Commission-adopted hourly avoided-cost series exists for Liberty's balancing authority area. Energy Division therefore values avoided energy at Liberty's flat purchased-power cost with no hourly shaping: $3.313¢ \times 1.00 = 3.313¢/\text{kWh}$. This replaces earlier approaches that weighted the energy component by a retail rate shape or by a large-IOU ACC shape; the ground-up calculation relies exclusively on Liberty's own revenue-requirement record.

Step 5. Solar weighting: generation capacity component. Liberty's system peak demand occurs on winter evenings, concentrated in December and January when ski resorts, hotels, and residential electric heating loads in the Lake Tahoe Basin operate simultaneously. The Liberty MCOS Report characterizes Liberty's peak as the winter night period. Solar generation produces zero output during winter evenings. The only generation capacity credit available to Liberty solar is from summer daytime load reduction, which modestly reduces Liberty's secondary summer peak demand, substantially lower than the winter evening maximum. Rather than estimating a judgmental factor, Energy Division measures coincidence directly as the share of annual solar output falling within Liberty's tariff-defined winter on-peak window (5:01 p.m. to 10:00 p.m., November through April), the window Liberty's

MCOS identifies as the system peak: approximately 2.0%. A cross-check using the top 100 modeled load hours yields approximately 0.3%, so the 2.0% value is conservative toward solar. $2.330\text{¢} \times 0.0196 = 0.046\text{¢/kWh}$. Parties may provide alternative evidence from Liberty's load data in their comments.

Step 6. Solar weighting: distribution TOU component. The marginal distribution TOU component reflects incremental distribution infrastructure costs incurred to serve demand during TOU constraint periods. Liberty's winter evening peak creates the dominant distribution constraint; solar does not coincide with this constraint. Because these demand-related costs are driven by the same winter evening constraint, Energy Division applies the same measured winter on-peak coincidence: $4.655\text{¢} \times 0.0196 = 0.091\text{¢/kWh}$. Parties with evidence of a binding summer distribution constraint may propose a supplemental factor in comments.

Step 7. Solar weighting: distribution non-TOU component. The marginal distribution non-TOU component reflects customer-coincident distribution costs: feeder capacity investment, transformer sizing, and line losses that arise from the physical presence of customers on the distribution system regardless of time of day. Solar generation at the point of load reduces line losses and defers feeder reconductoring investment during generation hours, regardless of on-peak/off-peak designation. For Liberty's mountainous distribution system, with long single-circuit feeders serving dispersed loads across Sierra Nevada terrain, per-customer marginal distribution costs of \$13.90/month²⁷ versus approximately \$8 to \$10/month for typical California IOUs), distributed solar arguably provides locational value. Nonetheless, because these costs are driven by the physical presence of customers on the system and continue regardless of export activity, Energy Division excludes this component from export compensation, consistent with the treatment of marginal customer costs in Table B-1: $5.727\text{¢} \times 0.00 = 0\text{¢/kWh}$. Parties may argue for a positive locational factor in comments.

Step 8. GHG avoided cost. Liberty's power supply is provided largely by NV Energy under the ESA. NV Energy North's generation portfolio serving the Sierra Nevada and Lake Tahoe area is predominantly natural gas combined cycle (NGCC). The marginal unit displaced when Liberty solar generates is an NGCC plant. Using EPA emission factors:²⁸ natural gas CO₂ emission factor = 0.05306 metric tons CO₂/MMBtu. For an NGCC plant at an 8,000 BTU/kWh heat rate (representing the marginal NV Energy NGCC unit at partial dispatch), CO₂ per kWh = $8,000 \text{ BTU/kWh} \times 0.05306 \text{ metric tons/MMBtu} \div 1,000,000 \text{ BTU/MMBtu} = 0.4245 \text{ metric tons CO}_2/\text{MWh}$. The California cap-and-trade allowance price for 2025 is approximately \$35.00/metric ton CO₂ based on recent CARB quarterly auction clearing prices.²⁹ GHG avoided cost = $0.4245 \text{ metric tons/MWh} \times \$35.00/\text{metric ton} = \$14.86/\text{MWh} = 1.486\text{¢/kWh}$.

Step 9. Summary table. The following table assembles all components:

27 Cal Advocates (Public Advocates Office) Exhibit CA-04, Witness Maricela Sierra, A.24-09-010 (Liberty Utilities TY 2025 GRC), Section V: Marginal Costs and Rate Design, Table 4-3 (Marginal Costs of Service Summary), filed 2 July 2025.

<https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2409010/8297/571368878.pdf>

28 US EPA, AP-42: Compilation of Air Emissions Factors, Chapter 1.4 Natural Gas Combustion. CO₂ emission factor for natural gas: approximately 53.06 kg CO₂/MMBtu (117 lb CO₂/MMBtu). For a natural gas combined-cycle unit at 8,000 BTU/kWh heat rate: $8,000 \times 53.06 / 1,000,000 = 0.425 \text{ metric tons CO}_2/\text{MWh}$. <https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors>

29 California Air Resources Board, Cap-and-Trade Program Auction Results. Current settlement prices and quarterly auction clearing prices published at CARB auction information page. 2025 allowance price approximately \$35/metric ton CO₂.

<https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/auction-information>. Retrieved February 2026.

Table B-3. Liberty NBT Export Compensation Calculation. All MCOS inputs from Cal Advocates Exhibit CA-04, A.24-09-010. GHG: EPA AP-42 and CARB quarterly auction data.

Component	MCOS (\$)	÷ 442m kWh	Raw ¢/kWh	Weight Factor	Solar-Wt. ¢/kWh
Generation energy	\$14,652,945	÷ 442m	3.313¢	1.00 (flat ESA cost)	3.313¢
Generation capacity	\$10,297,111	÷ 442m	2.330¢	0.0196 (winter on-peak coincidence)	0.046¢
Distribution TOU	\$20,576,733	÷ 442m	4.655¢	0.0196 (winter on-peak coincidence)	0.091¢
Distribution non-TOU	\$25,316,112	÷ 442m	5.727¢	0.00 (excluded: customer-coincident)	0¢
GHG (NGCC displacement)	n/a	n/a	n/a	0.4245 mt/MWh × \$35/mt	1.486¢
Customer costs (excluded)	\$11,140,807	—	—	Excluded: customer remains connected	0¢
Total avoided cost					4.936¢

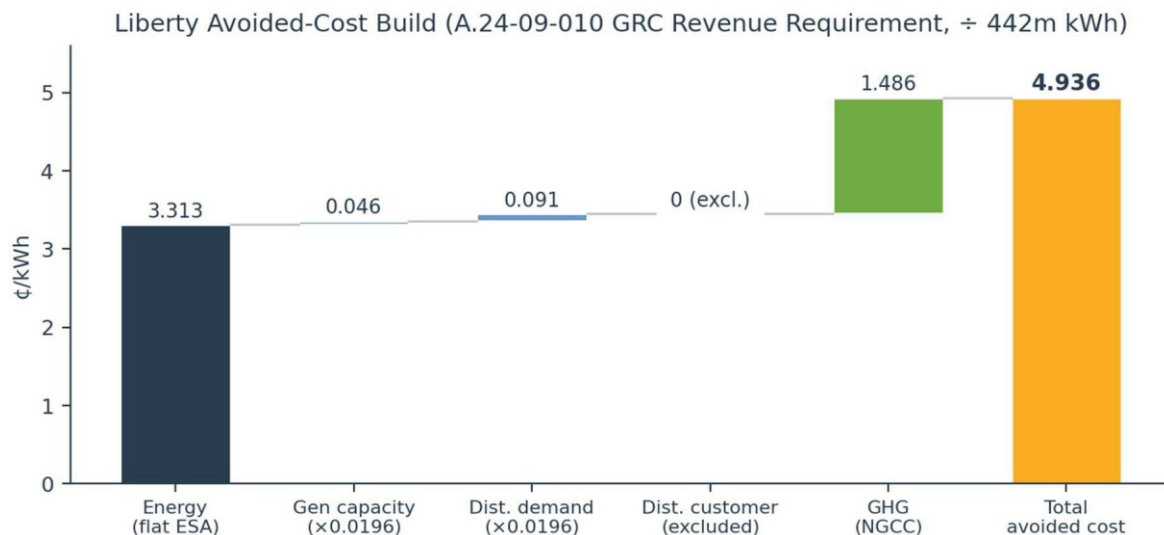


Figure B-3. Liberty avoided-cost build. The customer-related distribution component is excluded; the winter on-peak coincidence weighting reduces the capacity and demand-related distribution components to 0.14 ¢/kWh combined.

Step 10. Conversion to a floating percentage. The Liberty-specific avoided cost of 4.94 cents/kWh as a percentage of the solar-weighted retail rate is: D-1: $4.94 \div 49.1 = 10.1\%$. Staff recommends a floating percentage of the applicable TOU rate, set each year to equal the Liberty avoided cost, rather than a fixed percentage (see Section B-1). At current rates the percentage is approximately 10%, so D-1 customers receive approximately 4.94 cents/kWh. Liberty recalculates the percentage and the implied cents/kWh value in its annual Tier 1 advice letter as TOU rates and the avoided cost change through GRC proceedings.