Amping Up Flexibility: Quantifying the Grid Value of Load Management via Smart Electric Panels

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ABSTRACT

Rapid electrification of buildings and transportation is intensifying demand on local electric distribution systems. Conventional infrastructure upgrades, such as transformer replacements and service extensions, are increasingly costly, slow to deploy, and often mismatched to the localized and intermittent nature of new loads. This study evaluates how advanced, circuit-level load management technologies installed at the customer service point can mitigate these challenges and provide quantifiable value to both utilities and customers.

Using a representative California residential feeder, the analysis applies a detailed benefit valuation framework combining hourly load modeling, avoided cost estimation, and feeder-level capacity simulations. The framework quantifies how real-time load shaping at the household level can defer secondary distribution upgrades, reduce service extension costs, and optimize utilization of existing grid assets. Results show that targeted deployment of customer-sited control technologies can reduce per-feeder upgrade costs by up to $1.2 million and yield substantial per-household benefits by avoiding costly panel or service upsizing. Secondary distribution system deferral (in terms of avoided line and transformer replacements) and enhanced load flexibility drive the majority of system value.

These findings demonstrate that grid-interactive load management at the edge can play a critical role in managing electrification-driven load growth while maintaining reliability and affordability. By quantifying localized benefits and identifying threshold effects in distribution deferral value, this research informs how utilities and regulators can integrate distributed flexibility resources into existing planning frameworks, thereby enabling smarter investment, faster decarbonization, and more equitable access to electrification.

Introduction and Background

California's decarbonization goals, anchored in Senate Bill 100 and Executive Order N-79-20 (Senate Bill 100 2018; California, Executive Department 2020), are driving rapid electrification of vehicles, buildings, and appliances (CEC 2024). These transitions require a fundamental rethinking of distribution infrastructure, which was built around slow, incremental load growth. Electrification instead generates sharp, localized demand surges as clusters of homes add EV chargers and electric heat pumps (PG&E n.d.), frequently overwhelming service drops, secondary transformers, and feeder lines.

Conventional upgrade pathways are ill-equipped to respond. Transformer replacements can take over a year; underground service extensions require costly trenching and permitting (CPUC 2024; BAAQMD 2024). Meanwhile, many homes, particularly those built before 2000, are served by 100- to 150-amp panels that cannot support the simultaneous operation of new electric loads (SPUR 2024). Upgrading to a 200-amp panel can cost thousands of dollars, compounding the utility-side costs and creating significant barriers to electrification, especially in lower-income communities and older housing stock (Calisch and Wyent 2022). Smart electric panels offer a direct alternative to these barriers.

Load Flexibility and Grid Services from SPAN Edge ISP

SPAN Edge Intelligent Service Point (hereafter referred to as Edge ISP) is a service panel replacement installed at the meter that offers advanced monitoring and control capabilities over household electrical loads. Unlike traditional service panels, SPAN Edge ISP provides continuous circuit-level visibility and the ability to manage connected loads in real time. By integrating metering, sensing, and communication technologies, the device enables coordination between customer electricity use and utility system needs. Designed for utility or third-party ownership, SPAN Edge ISP is compatible with common panel configurations and can be deployed as part of broader utility electrification and grid modernization initiatives.

One of the distinguishing features of SPAN Edge ISP is its ability to reliably limit connected load by enabling household load flexibility. Through disaggregated, circuit-level monitoring and control via automated software, the panel can shift or curtail specific end uses, such as EV charging or water heating, to ensure that total concurrent load does not exceed a defined setpoint. This "firm service rating" allows for customers to adopt new electrification technologies without triggering upgrades to their existing electric service.

Industry Drivers

California's decarbonization policy has catalyzed rapid electrification, which in turn is exposing deep limitations in the state's distribution grid capacity. SPAN technology responds directly to four converging industry pressures: accelerating load growth, widespread panel and service capacity limitations, high-cost and slow-moving utility upgrade cycles, and regulatory friction around grid modernization investment. These forces, which are well documented in current utility filings, grid planning proceedings, and market assessments, point to an urgent need for modular, customer-sited load management solutions.

Electric Load Growth in a Decarbonizing Grid

California's transition to a decarbonized, electrified energy system is producing rapid and transformational electric load growth. There are three main sources of electric load growth:

- **Load Growth from EVs:** California's transportation sector electrification is advancing under the state's Advanced Clean Cars II regulations, which mandate that all new light-duty vehicle (LDV) sales be zero-emission by 2035 (Advanced Clean Cars II 2022). E3 forecasts that by 2035, 13.7 million passenger EVs and 407,000 commercial EVs will be on the road in California (CARB 2022).[1] While EV load can be flexible, unmanaged charging risks exacerbating system peaks, particularly at the secondary distribution level. For instance, a single Level 2 EV charger can draw between 7 to 11 kW, equivalent to the peak load of an entire household (Less and Walker 2026). If even a modest percentage of homes on a secondary transformer begin charging EVs simultaneously (such as upon returning home in the early evening or at the start of the off-peak period for the local utility rate), the aggregate load can quickly exceed the transformer's rated capacity. When this happens, utilities are often forced to initiate upgrades, either replacing the transformer itself, increasing conductor sizing, or upgrading service drops.
- **Building Electrification (BE) and Policy-Driven Load Growth:** The state's building decarbonization strategy, supported by regional mandates such as the Bay Area's Zero-NOx appliance rules, is accelerating load growth from space and water heating.

[1] 2022 CARB Scoping Plan PATHWAYS data on LDV Sales and Stock

Beginning in 2026, new residential construction statewide must be all-electric, with similar requirements for commercial buildings by 2029 (CEC 2024). Existing building retrofits will follow, with full replacement-on-burnout mandates phased in between 2027 and 2030. E3 estimates that electrification of these building loads could add 5,378 MW of new peak demand by 2035 (BAAQMD 2024).

- **Data Center and Digital Infrastructure Load:**[2] Driven by surging demand for AI and high-performance computing, data center load is emerging as a new and significant source of electricity demand. Nationwide trends show dramatic increases in data center capacity, and California is not exempt. E3 estimates that by 2050, data centers could account for approximately 3% of total statewide load (E3 2026).

In practice, EV, BE and Data Center load growth will materialize unevenly, increasing pressure on already constrained feeders and transformers in high-growth areas.

Growing Grid Infrastructure Upgrade and Panel Upsize Needs

California's ambitious building electrification and clean energy goals face a significant constraint rooted in legacy electrical infrastructure: inadequate panel capacity across much of the existing housing stock. Electrification of end uses such as space and water heating, vehicle charging, and cooking can drive both panel-level upgrades and utility-side service replacements. Without a coordinated strategy, this transformation risks becoming a major source of cost and delay for utilities, customers, and the grid.

Across the state's ~14 million households, an estimated 50% have electrical panels smaller than 200 amps which is insufficient for fully electrifying a typical home without service enhancements or load management solutions (SPUR 2024). While some homes with 100 –150 amp panels may electrify with careful planning, those below 100 amps will almost certainly require an upgrade. Events commonly triggering upgrades include EV charger installations, solar PV additions, HVAC replacements, and home renovations such as pool or spa additions.

The complexity and cost of implementing service upgrades vary significantly based on factors such as panel location, distance to the nearest distribution point, the number of customers per transformer, and whether the service is overhead or underground. These upgrades are not limited to the customer panel; they often involve utility-side enhancements and, at scale, necessitate upstream distribution system reinforcements. These collective impacts risk cascading into higher system costs and ratepayer burden.

Policy developments are increasingly focused on these grid impacts. The Powering Up Californians Act (SB410) mandates that the California Public Utilities Commission (CPUC) set maximum energization timelines and requires utilities to align annual grid investment planning with regional air quality objectives and to report on missed energization targets (Senate Bill 410 2023). These reforms highlight the growing recognition of the connection between electrification-driven upgrades and equity in grid access.

The implications are profound: service upgrades can cost homeowners anywhere from $2,000 up to $30,000 (without including the cost of the panel upgrade) and take over a year to implement due to permitting, backlog, and utility coordination (Calisch and Wyent 2022). At scale, these delays impede decarbonization timelines and increase total system costs.

[2] While SPAN products are not directly applicable to data center load growth, the deferral of residential upgrades enabled by SPAN Edge ISP allows utilities to allocate already limited distribution capex towards the interconnection of these high value new loads.

Long and Expensive T&D Procurement and Planning Process

Electric utilities across the U.S. are rapidly scaling up capital investment in transmission and distribution (T&D) infrastructure. From 2024–2028, more than half of medium-term utility capital spending is expected to be directed toward T&D (S&P Market Intelligence 2024). Key drivers of this trend include aging asset replacement, wildfire and climate resilience, grid modernization technologies (e.g., smart meters and automated restoration), and the need to accommodate electrification and DERs.

Spending on transmission infrastructure nearly tripled between 2003 and 2023, rising to $27.7 billion, while distribution capital spending rose by $31.4 billion (a 160% increase over the same period). The fiscal consequences of utility grid investments are manifesting in rate cases across the country. In 2023, U.S. electric utilities submitted $13.51 billion in rate increase requests, with a large share tied to T&D capital plans (EIA 2024).

T&D Procurement and Planning Challenges in California

The process for planning and executing grid upgrades remains lengthy and complex, often misaligned with the urgency of California's electrification goals. In response, the CPUC has mandated new reforms in 2024, requiring utilities to extend the planning horizon of their Distribution Planning Process (DPP), introduce a "pending loads" category, and assess load flexibility within their DPP filings. Still, infrastructure deployment remains slow. PG&E, for example, reports typical residential service upgrades take 10–30 days, but may extend beyond 8 months for more complex cases. New construction connections average 64 days. More significant distribution projects, such as substations and new circuits, often require 3–10 years from initiation to in-service (CPUC 2024).

These delays are rooted in procurement lead times, permitting, workforce constraints, and system coordination and can create bottlenecks for customers and developers alike. Long timelines also raise the total cost of deployment and risk deferring load growth needed to achieve state electrification targets.

Rising Costs in the Secondary Distribution System

While primary distribution upgrades typically receive planning focus, electrification is placing increasing stress on secondary systems, especially for residential and small commercial loads served at the last mile. According to PG&E's general rate case data, secondary distribution costs are smaller per kW than primary costs (ranging from ~$0.88 to $1.75/kW-year), yet their cumulative magnitude is substantial due to the growing base of EV charger connected loads (Figure 1) (Cutter et al. 2021).

Example Costs: PG&E GRC Data used for 2020 Avoided Cost Calculator			
PG&E Distribution Planning Area	Primary $/kW-yr	Secondary $/kW-yr	Secondary/ Primary Cost
Central Coast	$69.09	$1.04	2%
De Anza	$35.65	$1.01	3%
Diablo	$17.78	$1.56	9%
East Bay	$19.99	$0.88	4%
Fresno	$39.52	$1.36	3%
Humboldt	$73.97	$1.12	2%
Kern	$34.07	$1.23	4%
Los Padres	$56.49	$1.06	2%
Mission	$13.63	$0.97	7%
North Bay	$29.42	$1.75	6%
North Valley	$53.40	$1.26	2%
Peninsula	$31.79	$1.06	3%
Sacramento	$40.91	$1.22	3%
San Francisco	$40.41	$1.52	4%
San Jose	$40.12	$1.16	3%
Sierra	$30.65	$1.25	4%
Sonoma	$121.98	$1.28	1%
Stockton	$33.36	$1.34	4%
Yosemite	$60.18	$1.56	3%

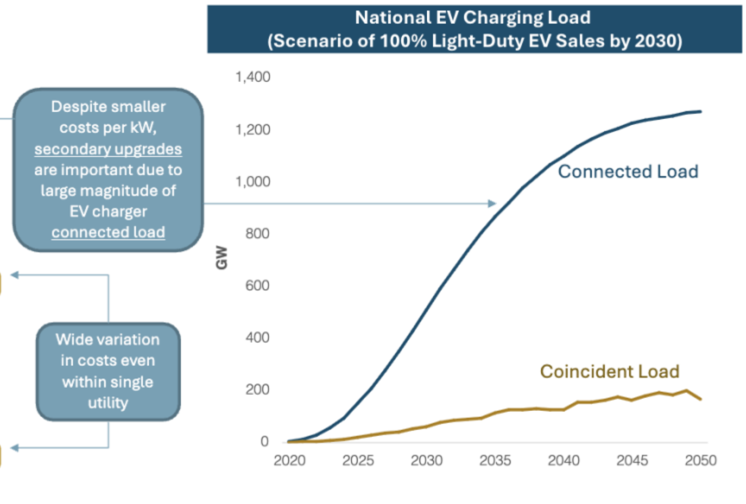

Figure 1. PG&E Distribution Costs and National EV Charging Load Forecast

In planning areas like Mission and Diablo, secondary costs comprise up to 9% of primary infrastructure costs. As light-duty EV adoption expands under California's 2035 ZEV mandate, these downstream systems will require significant reinforcement, even when upstream capacity is sufficient. A 2023 study by E3 and GridLab highlights how secondary upgrades, though often unrecognized in traditional planning, could drive large cumulative costs due to high connected loads relative to coincident peak (if not well-managed). This underscores the need for technologies that can manage localized load impacts without full infrastructure replacement.

Grid Modernization Regulatory Challenges

Despite widespread recognition of the need for grid modernization, utility efforts to secure ratepayer funding for advanced infrastructure upgrades often falter under regulatory scrutiny. In 2021, utilities across the U.S. filed for $14.7 billion in grid modernization investments. Of this, regulators approved just $904 million, deferring $12.7 billion subject to further review and rejecting the remainder (Trabish 2022). Many proposals stalled due to high capital costs, lack of clearly defined benefits, or uncertainty about technology maturity. The lengthy and adversarial nature of regulatory review often deters utilities from pursuing innovative or nontraditional solutions. This dynamic has created an opening for lower-cost, modular technologies that can be deployed incrementally and evaluated on performance.

Methodology

To quantify the grid and customer value of SPAN Edge ISP, E3 developed a benefit value stack analysis applied to a representative summer-peaking feeder selected from a California IOU's public grid hosting capacity database. The selected feeder represents conditions typical of residential neighborhoods with emerging electrification loads, including new construction activity and moderate rooftop solar adoption. E3 estimated benefits from deploying SPAN Edge ISP devices under varying levels of household electrification and SPAN device deployment, incorporating hourly load shapes for EVs and BE, adjusted to reflect the impacts of SPAN's load management capabilities. Where applicable, E3 categorized and quantified benefits using established avoided cost frameworks and developed additional calculations to capture distribution and customer-level values not typically included in standard cost-effectiveness tools.

Feeder Selection and Baseline Characterization

E3 leveraged publicly available IOU hosting capacity databases, (Southern California Edison, n.d., "Integration Capacity Analysis Map") to identify a representative distribution feeder with primarily residential customers, constrained headroom, and electrification potential. The feeder includes 502 single-family homes and operates on a 12 kV underground system with an existing peak load of 6.2 MW and ~0.5 MW of headroom. Figure 2 illustrates the geographic layout of the selected distribution feeder in Southern California. This territory includes both established neighborhoods and newly constructed housing developments, with underground electrical distribution circuit shown as line segments in the image below.

Figure 2. Satellite Imagery of Selected Feeder Source: IOU ICA Database

As summarized in Figure 3, the selected feeder's load profile displays summer peak behavior and high evening loads, the timing of which aligns with EV charging and BE demand. These characteristics make the selected feeder a high-value candidate for deferral of capital investment through targeted DER deployment.

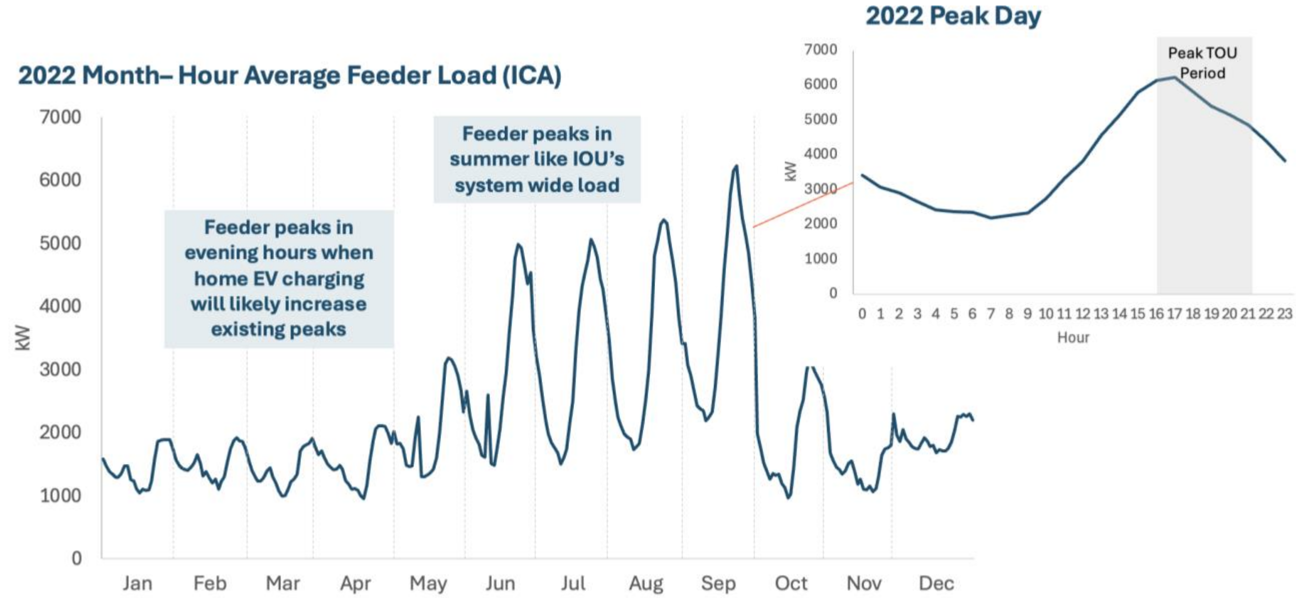

Figure 3. Representative Feeder Load Profile Source: CA IOU ICA Database

BE and EV Load Forecasting with and without SPAN Edge ISP

After feeder selection, E3 assessed how SPAN technology could reshape load profiles and reduce the need for distribution system upgrades under realistic scenarios of adoption and demand growth. This involved constructing EV and BE load shapes, both with and without the influence of SPAN Edge ISP. These shapes were designed to reflect realistic charging behavior and appliance usage patterns, as well as SPAN technical capabilities to shift or throttle load to avoid peak periods.

EV Load Shapes

E3 leveraged its EVGrid model, a bottom-up simulation tool that estimates EV charging needs based on vehicle characteristics and real-world travel behavior, to develop EV charging profiles. The model calculates where, when, and how much charging is required for a diverse population of vehicles. Multiple scenarios of driver behavior were simulated (Figure 4):

- **Unmanaged charging** assumes drivers begin charging immediately upon returning home, typically during on-peak periods.
- **Managed charging** assumes drivers defer charging until the start of off-peak pricing windows, often resulting in rebound peaks.
- **SPAN-managed charging** models a scenario in which charging is distributed across off-peak hours with minimal power draw, subject to meeting all travel demands. This represents a theoretical maximum load minimization potential enabled by SPAN real-time control capabilities. The real-time control capabilities take two forms: circuit-level relay control in which SPAN will pause EV charging by opening the relays for the EVSE circuit, and load throttling in which SPAN will continuously adjust the power draw from the electric vehicle service equipment (EVSE) to maintain the firm-service limit. Managed charging via load throttling requires an EV charger that SPAN can connect to via software APIs. This could be achieved using the SPAN Drive EV charger or any

third-party EVSE provider that SPAN has partnered with, including Tesla. EVSE costs were not included in this analysis.

Figure 4 shows population average charging behavior under the three scenarios and does not indicate a single vehicle's behavior. For example, the SPAN-optimized charging scenario does not represent all vehicles being at home and charging during the middle of the day and all vehicles away from home during the peak-period. Rather, this represents the population average, where different vehicles have different driving and parking schedules, enabling charging demand of the population in aggregate to be spread across a broad set of hours.

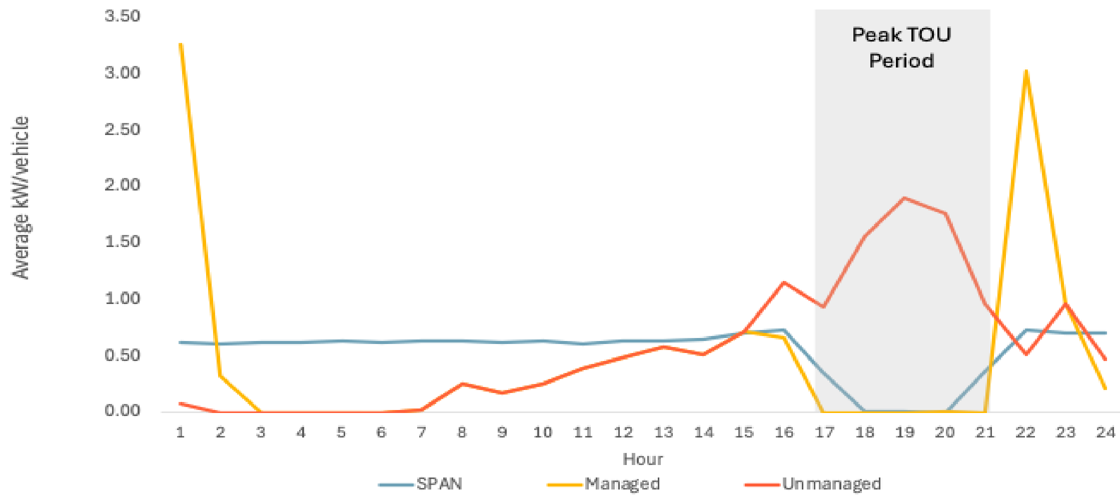

Figure 4. Population average home charging load of 200 vehicles on a summer day Source: E3 EVGrid tool

In the absence of SPAN Edge ISP, E3 assumes a behavioral mix of 60% TOU-managed and 40% unmanaged charging. With SPAN Edge ISP, 100% of the modeled vehicles are assumed to follow SPAN-optimized charging schedules.

BE Load Shapes

E3 leveraged household-level energy use data from the National Renewable Energy Laboratory's (NREL) ResStock database to construct building load profiles for the homes in the selected feeder (Parker et al. 2025). For each sampled home in the selected study area (Los Angeles County), E3 created pre- and post-electrification hourly load profiles.[3] Impact from SPAN on BE was modeled as a shift of 11% of flexible end-use load (e.g., water heating, HVAC) from peak and mid-peak hours to off-peak periods (Figure 5). SPAN's internal Fleet Energy Management dataset, which quantifies load flexibility during two-hour event windows for different appliance types, informed this load shift percentage.

[3] Building characteristics: 2,500 ft^2, detached single-family house with central cooling, built in 2010s

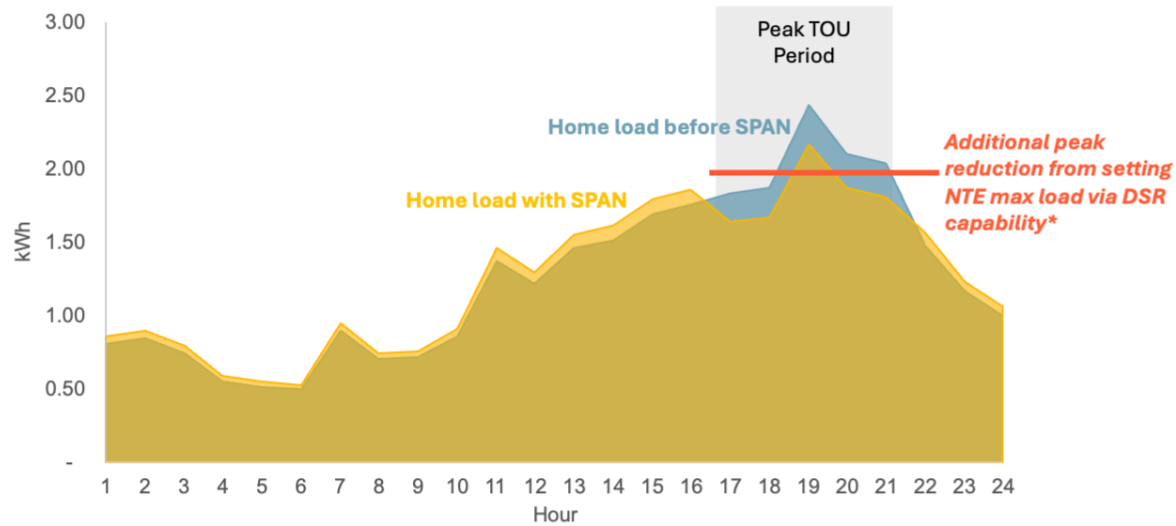

Figure 5. Summer Day Single House BE Load Shifting with SPAN Source: ResStock; SPAN assumptions. *DSR capability not modeled as part of this analysis. Graphic depiction is for illustrative purposes only.

While SPAN Edge ISP can also enforce a Dynamic Service Rating (DSR) over a group of homes, E3 did not explicitly model this constraint in the hourly simulation since DSR operates primarily at a sub-hourly level and would not meaningfully change net hourly demand. The analysis therefore represents a more conservative approach where customers experience minimal to no noticeable impact on an hourly basis. DSR functionality could increase net benefits shown in the analysis by enforcing a lower service limit on peak days.

Feeder-Level Load Modeling

E3 applied the incremental electrification loads, derived from both EV and BE modeling to the representative feeder, adding varying levels of load from projected heat pump and EV adoption to the historical baseline feeder load:[4]

- **Moderate EV and heat pump** uptake assumes 54% EV adoption and 27% penetration for heat pumps
- **Accelerated EV uptake** assumes 2035 projected penetration of EVs (85%); heat pump penetration held at moderate levels (27%)

E3 then adjusted these load profiles under varying levels of SPAN Edge ISP deployment: low (10%), medium (50%), and high (90%) adoption across electrifying customers.[5] The aim was to evaluate how SPAN Edge ISP could shift load from peak periods and mitigate infrastructure upgrade needs at various levels of technology saturation. This modeling provided the foundation for estimating avoided utility capital costs, customer upgrade savings, and demand-side flexibility value associated with SPAN deployment.

[4] HP and EV adoption levels come from the California Energy Commission's [2023 Integrated Energy Policy Report](#)

[5] For this analysis, deployment percentages translated to 28, 136 and 244 units for low, mid and high assumptions, respectively

Distribution Upgrade Avoidance and Threshold Effects

Feeder upgrade triggers are modeled as capacity exceedances (Figure 6). Where electrification causes hourly load to exceed feeder limits, E3 assumes a distribution upgrade (minimum 0.5 MW increment) is required and credits primary distribution deferral benefits when SPAN Edge ISP load shaping successfully mitigates the overload.

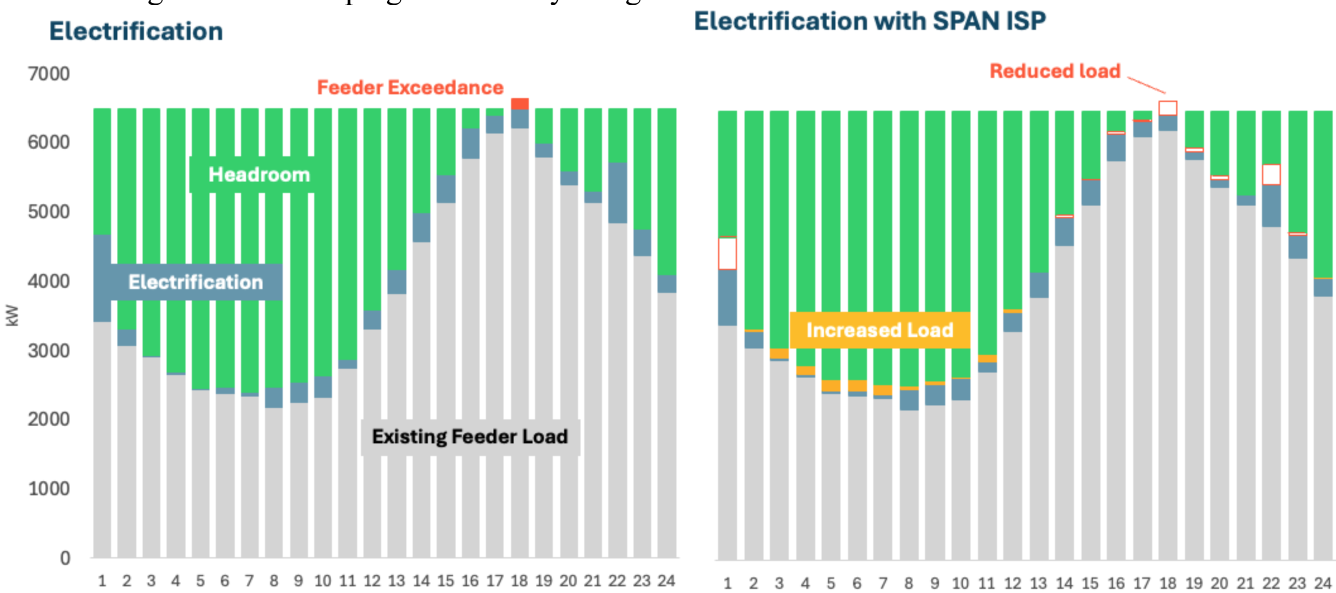

Figure 6. Illustrative feeder-level baseline and electrified load with and without SPAN. Source: E3 analysis and IOU hosting capacity database

It is important to note that the threshold nature of distribution upgrades creates a non-linear relationship between SPAN Edge ISP adoption and benefits: penetration up to a certain point can avoid a full upgrade and yield high per-unit benefits, while partial deployment in high-load scenarios may fall short and provide no deferral value at all. Similar to energy-limited storage, the marginal capacity of SPAN Edge ISP value decreases with scale.

Benefit Analysis by Value Stack Component

After developing load shapes with and without SPAN Edge ISP and determining feeder upgrade triggers, E3 calculated costs and benefits for each of the following components of the valuation framework:

- **Energy, Generation Capacity, and Transmission Capacity:** System-level savings were quantified using hourly prices from the 2024 California Avoided Cost Calculator (ACC), applied to the shifted load enabled by SPAN Edge ISP. For customer-level calculations, avoided energy costs reflect utility bill savings by shifting energy use from peak and mid-peak to off-peak hours in response to TOU rate. Generation capacity benefits are derived from customer incentives from participation in demand response (Critical Peak Pricing) programs.[6]

[6] E3 assumed $20 per household per year based on average annual savings for participation in SCE's Power Saver Rewards Program. SPAN ISP Edge could enable homeowners to enroll in additional DR offerings that yield higher annual incentives, which would increase the range of potential customer benefits from SPAN Edge ISP.

- **Primary Distribution:** Distribution deferral value is based on the projected peak reduction from SPAN deployment and the avoided cost of capacity upgrades at the feeder level. To localize benefits, E3 reverses the ACC's regional averaging of distribution costs by reapplying upstream input parameters from SCE's DDOR. Specifically, per-unit avoided upgrade costs ($/kW) are combined with SCE's marginal cost factor (11.48%) and O&M savings to produce a feeder-specific deferred value of $197/kW-year.
- **Secondary Distribution:** Transformer and final line cost estimates use typical upgrade costs for pad-mounted transformers serving small groups of homes, attributing savings where SPAN Edge ISP deployment deferred or reduced the need for these upgrades.[7] This analysis assumes uniform distribution of SPAN panel deployment across the representative feeder. If SPAN panels were instead deployed only to constrained FLTs, the likelihood of avoiding upstream upgrades would increase thereby realizing additional benefits not currently captured in this analysis.
- **Service Extension and Customer Panel:** The analysis included avoided utility allowances for service extensions (CPUC Electric Tariff Rule 15) and avoided customer costs for panel upsizing. E3 assumes that in the counterfactual, 20% of electrifying homes would otherwise trigger a costly service extension, with an average cost of $8,000 plus the utility service extension allowance. It is important to note that benefits to both the utility and the customer can vary significantly depending on whether the standard panel upsize would have triggered a service extension upgrade, and the cost of this extension beyond the utility's standard allowance. The 20% assumption used for this analysis will likely be much higher if initial deployments of SPAN ISP Edge are targeted to high-growth high-congestion feeders. The standard panel upgrade cost assumption is $3,000 per home, based on statewide averages.[8] SPAN Edge ISP panel costs are based on the cost of the panel and monthly service fees.[9]

Benefit Analysis Results based on Representative Feeder

Customer Benefits

Customer benefits per panel are consistent across SPAN deployment levels and only slightly increase between moderate and more aggressive EV adoption trajectories, ranging from approximately $7,900 to $8,100 per panel, respectively. This is because avoided service extension, avoided panel cost, and capacity benefits are consistent at the customer level regardless of electrification levels. Energy benefits only vary slightly as they are primarily driven by enhanced EV management and higher participation rates in managed charging. Notably, these

[7] E3 assumes a per-unit FLT upgrade cost of $11,290 (including transformer and service drop), based on SCE's 2024 Unit Cost Guide. Diversity factors are applied to adjust for realistic coincidence of household loads. Based on the share of homes electrifying on a FLT and the # of homes on each FLT, savings are realized if the reduction in required capacity post-electrification from SPAN panels is sufficient to avoid a pole-mount or pad top transformer replacement.

[8] Installation costs from certified electrician included in standard panel cost estimate, based on https://homes.rewiringamerica.org/articles/electrical-panel/electrical-panel-upgrade-pros-cons. Since SPAN ISP does not require electrician installation, SPAN Edge ISP device costs are limited to panel cost and software fee.

[9] SPAN Edge ISP costs as follows: $1,500 upfront cost of SPAN Edge ISP + annual service cost of $120/year * 10 years

benefits remain stable across SPAN adoption levels, underscoring that individual customers realize high value regardless of overall system penetration.

Utility Benefits: Panel-level

Figure 7 summarizes per-panel benefits from the utility perspective, demonstrating that varying levels of electrification can yield meaningful variation in utility benefits depending on the level of SPAN Edge ISP penetration and corresponding avoided infrastructure costs. With moderate EV and BE adoption, per-panel utility benefits range from approximately $10,600 at low SPAN Edge ISP adoption to $3,600 at high adoption levels. This decline in per-panel value as penetration increases reflects the threshold nature of distribution upgrades: a small number of panels (in this case, 28 units) can avoid a costly infrastructure investment, but the marginal benefit of each additional panel diminishes as system needs are already met. Across all Edge ISP deployment levels, bulk system benefits (energy, capacity, transmission) remain consistent, largely driven by the ability of SPAN panels to manage EV charging loads.

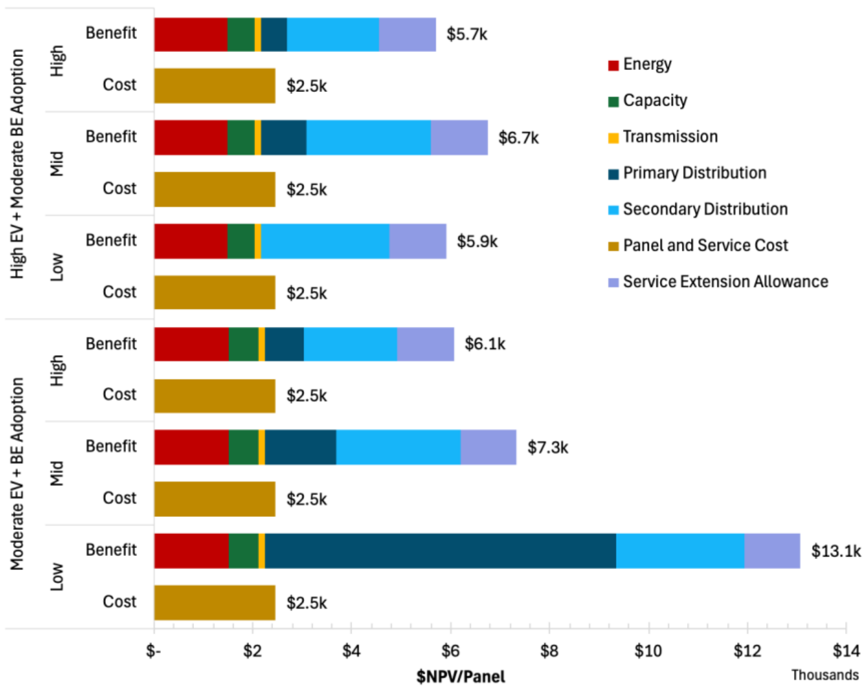

Figure 7. Utility Benefits: $/Panel[10] NPV value represents a 25 yr. lifetime discounted based on SCE's WACC, 7.4%

Under higher EV adoption with moderate heat pump penetration the pattern is similar. Per-panel utility benefits range from $3,400 at low adoption to $3,200 at high adoption. Importantly, primary distribution benefits are not captured at low SPAN Edge ISP adoption, reaffirming the requirement for critical mass to unlock feeder-level upgrade deferrals. Taken together, these results demonstrate that targeted, moderate deployment levels yield the highest cost-effectiveness per dollar invested, while high saturation primarily amplifies bulk system benefits rather than distribution savings.

[10] Note: Low, Mid and High refer to the level of SPAN Edge ISP deployment: low (10%), mid (50%), and high (90%).

Utility Benefits: Feeder-level

Feeder-level utility benefits from SPAN Edge ISP deployment vary significantly by both electrification intensity and SPAN penetration levels, reflecting the interplay between localized grid constraints and the threshold-based nature of distribution upgrades. As summarized in Figure 8, feeder-level total net benefits can reach up to $0.9 million under moderate EV and BE adoption and $1.2 million per feeder under high EV adoption at full SPAN saturation. Under high EV and moderate BE adoption, primary distribution upgrade deferral is captured at mid and high SPAN deployment levels, holding constant across those cases since the same feeder upgrade is avoided. Secondary distribution benefits, by contrast, scale with adoption: higher SPAN Edge ISP penetration enables greater deferral of transformer and service line upgrades, increasing total net benefits per feeder. Bulk system benefits (i.e., energy, capacity, and transmission) also rise with SPAN Edge ISP saturation, driven by the device's ability to reshape EV load profiles in ways that reduce coincident peaks.

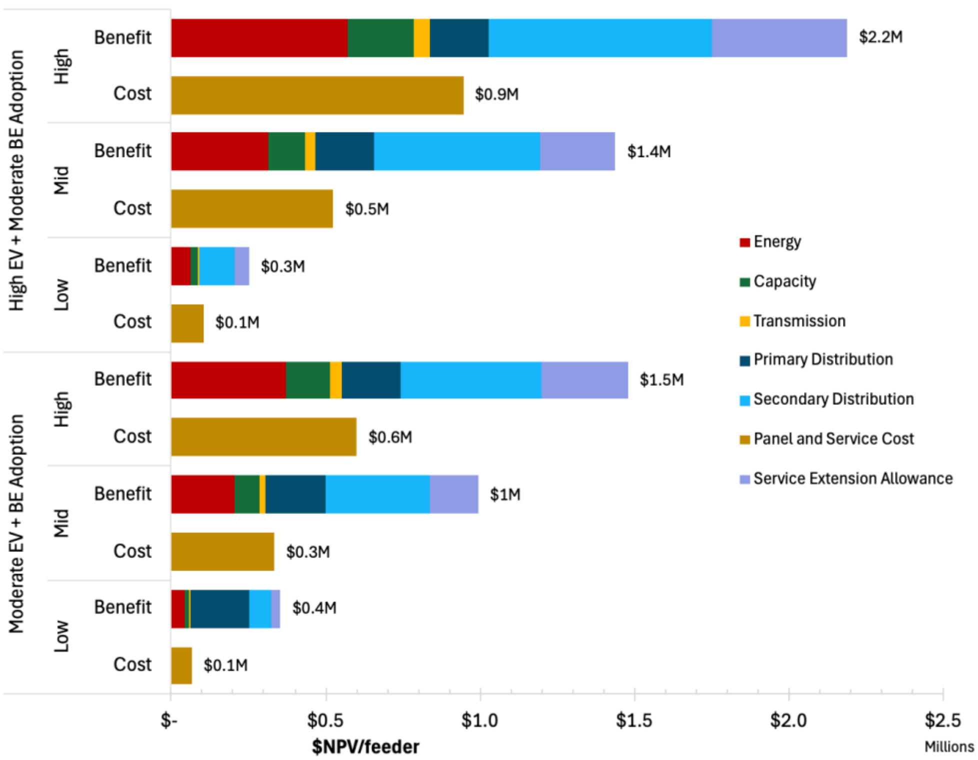

Figure 8. Utility Benefits - $/Feeder[11]

Qualitative Benefits

Smart electrical panels such as SPAN Edge ISP provide qualitative benefits beyond those captured in E3's benefit-cost framework. For utilities, they can reduce barriers to electrification by enabling customers to add new electric loads, such as EVs and heat pumps, without requiring panel or service upgrades. This supports load growth and electricity sales while limiting strain on distribution infrastructure. Circuit-level demand management offers a flexible, incremental

[11] Note: Low, Mid and High refer to the level of SPAN Edge ISP deployment: low (10%), mid (50%), and high (90%)

alternative to traditional system upgrades, potentially supporting non-wires alternatives and deferring capital expenditures in high-need areas. By reducing project scope and complexity, smart panels may also ease regulatory scrutiny related to cost-effectiveness, affordability, and equity. Overall, they can help utilities advance electrification and decarbonization goals while maintaining customer affordability.

For customers, smart panels lower the technical, procedural, and cost barriers associated with electrification. Avoiding service upgrades reduces delays, disruption, and expense when adding electric appliances or vehicles. Load management features allow households to shift usage away from peak periods, creating bill savings opportunities under time-of-use rates. Circuit-level visibility enhances understanding of energy consumption and supports participation in demand-side programs or dynamic pricing. Together, these capabilities position smart panels as an enabling technology for equitable, scalable electrification across California's diverse housing stock.

Conclusions

As jurisdictions across the US advance decarbonization goals, utilities and regulators face pressure to manage rapid electrification alongside rising distribution upgrade costs and timelines. This analysis shows that utility ownership and deployment of SPAN Edge ISP can deliver meaningful value to utilities and residential customers under varied electrification conditions. For customers, SPAN Edge ISP provides high net benefits of about $8,000 per panel from avoided panel upgrades, deferred service extension costs, and energy bill savings from managed load shifting. These benefits remain stable even at low deployment levels.

At the distribution level, targeted deployment can defer or avoid upgrades to transformers, service lines, and feeders. Utility benefits per panel range from two to seven times installed cost, with the highest returns in constrained areas. Because upgrades are triggered in threshold increments, benefits do not scale linearly. Early installations can avoid specific upgrades, while additional panels beyond the deferral threshold yield diminishing returns. At higher adoption levels, aggregated load shaping can achieve peak reduction with less disruption to individual households.

As EV adoption increases, ISP value grows because managed EV charging drives much of the grid benefit. Although extreme load growth may still trigger upgrades, strategic deployment in high growth, capacity constrained feeders can maximize grid value.

For deployment, utilities must consider targeting installations in feeders nearing capacity or with high EV growth, aligning ownership and cost recovery with the panel's role as grid infrastructure, and coordinating with DER and demand flexibility strategies. Utility scale deployment will require CPUC approval through existing or new funding pathways. Most grid investments currently occur through General Rate Case filings. Three potential pathways for California IOUs include: Rule 15 and 16 allowances for service extensions, where smart panels could be recovered if lower cost than traditional upgrades; AMI 2.0 proposals, where smart panels integrated with grid data systems could be included as capital expenditures; and performance based incentive frameworks that tie utility revenue to metrics such as peak load reduction, encouraging lower cost solutions like smart panels (CPUC n.d.; SCE 2026).

Taken together, these findings suggest that smart electric panels are not merely a customer amenity but a strategic grid asset. If deployed with intention and regulatory alignment, they can play a central role in enabling affordable, scalable electrification in California and beyond.

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