Next Steps for Affordability as the Grid Advances

Five pathways from GridFWD 2026 and the examples behind them

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IN BRIEF

- Settle who pays for a large load's grid upgrades before interconnection, as Utah has in law.
- Look for capacity on the existing grid first. E.ON estimates live data would free 350 MW across its own territory.
- Judge spending by benefit per dollar. PG&E's screening cut 2,000 flagged towers to 291.
- Change what earns a utility a return. Steel still earns four times the return of software.
- Get help to customers who qualify. In Connecticut, 31% are eligible and 17% are enrolled.

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FIGURES SPEAKERS PUT ON THE PROBLEM AND THE PATHWAYS

FIGURE	WHAT IT MEASURES	SPEAKER
46 states	saw electricity prices rise, 2024 to 2025	Peter Cappers, Lawrence Berkeley National Laboratory
1 in 6	households behind on utility bills; about $25 billion owed	Chris Medina, BlastPoint
$7 billion	in benefits to other ratepayers from Entergy's large-load contracts	Laura Landreaux, Entergy Arkansas
350 MW	of distribution capacity E.ON estimates live data would free	Florian Hintz, E.ON
$2 billion	of infrastructure BC Hydro's savings plan helps avoid	Jason Scultety, BC Hydro
7 to 8 times	rate impact of a dollar of operating expense versus a dollar of capital	Quinn Nakayama, PG&E
4 times	the return a dollar of hardware earns over a dollar of software	Luigi Montana, envelio
up to 80%	bill relief in Portland General Electric's income-tiered discount	Jaki Ferchland, PGE

Each figure is one speaker's statement at the conference, not an independent estimate.

Why Now

Electricity prices rose in 46 states between 2024 and 2025. Over the five years before that, from 2019 to 2024, inflation-adjusted prices fell in 28 states, according to Peter Cappers, a staff scientist at Lawrence Berkeley National Laboratory. The change lands on a bill that households treat as nearly untouchable: it ranks just behind rent or mortgage, said Joseph Pereira, director of the Colorado Office of the Utility Consumer Advocate. More than a third of US households already spend over 5% of their income on electricity, a share that has been growing, reported Christopher Porter, vice president of grid edge at Resource Innovations. The national average retail rate is up by one-third since 2019, Porter said, faster than general inflation. One in six households are behind on utility bills and total utility debt is about $25 billion and growing, according to figures presented by Chris Medina, a go-to-market engineer at the customer analytics firm BlastPoint.

During the closing plenary, moderator Bryce Yonker, executive director and CEO of Grid Forward, asked whether the next two or three years will look like the last. Raiford Smith, global director of power and energy at Google, answered maybe: it depends on whether conflicts in the Middle East and Latin America settle, whether supply gets unblocked, and whether tariff policy changes. Peter Fox-Penner, a principal at The Brattle Group, answered no. Fox-Penner expects a long upward price cycle, but said responses are starting to kick in: utilities are taking load flexibility seriously, and pressure is beginning to move transmission planning. Yonker answered yes, and added a hope that the answer turns out to be no.

The event's sessions preceding that exchange offered five ways to change the answer. Each section below leads with the action, shows who has taken it, and notes where speakers disagreed.

THE FIVE PATHWAYS AND HOW THEY ALIGN WITH THE GRIDFWD 2026 THEMES

PATHWAY	Load Growth, New Resources & Flexibility	Rate Design & Cost Causation	Effective Grid Utilization	Capital Efficiency	Strategic Investments & Technology	Policy & Regulatory Frameworks	Customer Agency & Safeguards
Align Cost Allocation for New Large Loads	●	●				●	
Use the Grid Already Built	●	●	●	●			
Spend Where Each Dollar Buys the Most			●	●	●	●	
Pay Utilities for the Cheaper Option			●		●		●
Get Help to the Customers Who Qualify		●					●

A mark means the section cites a session from that event theme. Plenary sessions sit outside the themes and are not shown.

Align Cost Allocation for New Large Loads

Event Themes: Load Growth, New Resources & Flexibility · Rate Design & Cost Causation · Policy & Regulatory Frameworks

Settling who pays for a large load's grid upgrades before interconnection helps to keep those costs off other customers' bills. Utah has written the rule into law: under its SB 132 large-load framework, the utility may source power for data centers as long as the data centers pay for their own upgrades and infrastructure consequences, reported Tim Kowalchik, director of research at the Utah Office of Energy Development.

The requests are large, and nobody is sure how many are real. Adam Keech, senior vice president of market services at PJM Interconnection, reported that the grid operator faces about 80 GW of projected data center load growth in roughly five years. That figure is hard to plan around because nobody knows whether it will be 80, 40, or 20, said Cy McGeady, head of energy policy at Equinix, who argued that planning should move from a forecast to an order book backed by financial commitment. PJM is not alone: SPP has received 32 large load requests totaling 15 gigawatts against a 55 gigawatt system peak, reported Carrie Simpson, vice president of markets at SPP. Requests like these have already moved budgets. Fox-Penner said large interconnection queues, and the supply-chain inflation they caused, drove the industry's planned expenditures of $1.1 trillion over ten years and record rate increases.

Load growth does not have to raise other customers' bills. Laura Landreaux, president and CEO of Entergy Arkansas, said Entergy's fair share plus data center contracts generated over $7 billion in benefits to lower cost pressures for general ratepayers across three states. Separately, Cappers found that load growth is on average not correlated, positively or negatively, with retail rates in most places. What matters is who pays for the upgrades.

WHAT TO DO

- **Legislators and regulators:** Assign the cost of grid upgrades to the large loads that need them before interconnection. Utah's SB 132 does this in law.
- **Utilities:** Write large-load contracts that return benefits to other ratepayers. Entergy reports over $7 billion across three states.
- **Planners and grid operators:** Plan from an order book backed by financial commitment. This is a proposal from a data center operator.

Use the Grid Already Built

Event Themes: Effective Grid Utilization · Load Growth, New Resources & Flexibility · Rate Design & Cost Causation · Capital Efficiency

Capacity found on the existing grid is capacity customers do not pay to build. The grid is built for peak hours that occur only about 50 to 100 hours a year, so it sits at roughly 50% utilization the rest of the year, said Giovanni Herazo, head of solution architecture and engineering at Schneider Electric. Building for those hours keeps getting more expensive. Dennis Mabe, CEO of Randolph EMC, said a same-size substation transformer now costs about $1.3 million with roughly a 26-month delivery versus about $500,000 for the one it replaces.

PRICE OF A SAME-SIZE SUBSTATION TRANSFORMER



Source: Dennis Mabe, Randolph EMC. One cooperative's purchases; delivery now roughly 26 months.

Live operational data is the first place to look. Florian Hintz, head of project and requirement management at E.ON, reported that using live smart meter and substation data rather than worst-case calculations would free an estimated 350 MW of distribution capacity across its territory, a figure scaled up from one grid area. BC Hydro is planning around customer-side savings. Its Power Smart 2.0 plan targets 800 MW of capacity savings and 2,200 GWh of energy savings by 2030, which helps avoid $2 billion in infrastructure, reported Jason Scultety, senior program manager for capacity products at BC Hydro.

Rate design is a second way to absorb demand without new wires. One default tariff suggests customers will accept it. Xcel Colorado's default residential time-of-use tariff, launched in 2021, saw a customer opt-out rate below 2%, reported Emma Rodvien, principal for regulatory innovation at the Regulatory Assistance Project (RAP). Speakers split on what such rates do to low-income households. Anthony Star, a senior principal at Synapse, warned about volatility: "if one month your electric bill goes up $50 or something, and you have to make a decision about what bills you're going to pay, that is a real burden on households." Yan Flishenbaum, director of rate engineering at Con Edison, reported a different experience: in a roughly six-year Con Edison demand-based time-of-use pilot, low-income customers were among the largest groups asking to stay on the demand rates.

WHAT TO DO

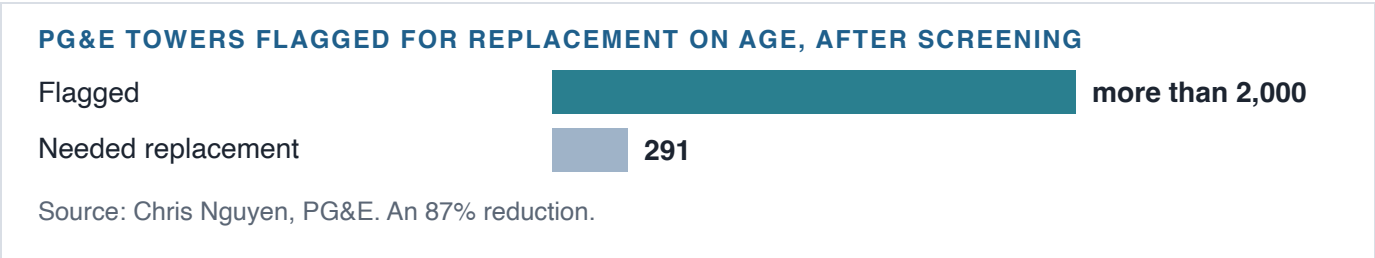
- **Utilities:** Use live meter and substation data to find headroom before reinforcing a circuit. E.ON estimates 350 MW, scaled up from one grid area.
- **Utilities:** Set customer-side savings targets large enough to defer construction. BC Hydro's plan targets 800 MW by 2030.
- **Utilities and regulators:** Make time-of-use the default rate and track what it does to low-income bills. Xcel Colorado's default has run since 2021 with an opt-out rate below 2%.

Spend Where Each Dollar Buys the Most

Event Themes: Effective Grid Utilization · Capital Efficiency · Strategic Investments & Technology · Policy & Regulatory Frameworks

Judging operations and safety spending by what each dollar buys the ratepayer can change the answer. Start with operations. Quinn Nakayama, senior director of grid research, innovation, and development at PG&E, said a dollar of utility operational expense has about the same customer rate impact as 7 to 8 dollars of capital expenditure, which makes cutting operational expense the stronger lever for lowering rates. Much of that expense, Nakayama added, sits with inspections and vegetation management contractors who cost two and a half times more than full-time employees. Tamara Mendelsohn, chief operating officer of Overstory, which sells the analysis, said applying AI satellite analysis to identify clear vegetation spans saves utilities tens of millions of dollars in vegetation management budgets.

Targeted review beats blanket replacement. Chris Nguyen, a senior manager and transmission line engineer at PG&E, reported that screening more than 2,000 towers flagged for replacement on age found only 291 needed replacement, an 87% reduction. Nat Skinner, deputy director for energy at the Public Advocates Office at the California Public Utilities Commission applied the same logic to wildfire: mitigation should be judged on risk reduction per dollar. Skinner put undergrounding at upwards of $10 million per mile and covered conductor at about $1 million per mile, so one mile of undergrounding must cut risk ten times as much as a mile of covered conductor to justify its cost. Fast-trip settings and public safety power shutoffs have already cut California wildfire ignition risk by about 60 to 70%, Skinner said. Any further safety spending must be benchmarked against that baseline.



Regulators can require the analysis before they authorize safety capital. The Utah Public Service Commission has told utilities about five times to bring more cost-benefit analysis for their wildfire plans, reported Michele Beck, executive director of the Utah Office of Consumer Services, who gave the count from memory. Beck put the balance between safety and affordability this way: "But we also cannot afford to write a blank check. Right? So that's the rub."

WHAT TO DO

- **Utilities:** Cut operating expense first. PG&E puts the rate impact of an operating dollar at 7 to 8 capital dollars.
- **Utilities:** Screen assets on condition before replacing them on age. PG&E's screening cut more than 2,000 flagged towers to 291.
- **Utilities:** Target vegetation work with satellite analysis. Overstory, which sells the analysis, puts the savings in the tens of millions of dollars.
- **Regulators:** Require cost-benefit analysis, measured as risk reduction per dollar, before authorizing safety capital. Utah's commission has asked for it repeatedly.

Pay Utilities for the Cheaper Option

Event Themes: Effective Grid Utilization · Strategic Investments & Technology · Customer Agency & Safeguards

Changing what earns a utility a return can make the cheaper option the one that pays. Most of the steps above ask utilities to spend less on physical assets, and the way utilities are paid points the other way. Traditional cost of service regulation creates a financial bias toward capital-intensive physical assets over digital software alternatives, said Ann McCabe, a commissioner on the Illinois Commerce Commission. Luigi Montana, CEO of envelio Inc., put a number on it: "$1 of hardware, of steel, of substation feeder upgrades earns four times the return for utility than $1 of software." The same incentive reaches computing, where utility financial incentives favor building on-site physical server infrastructure over cheaper cloud computing subscription models because hardware earns rate-base returns, reported Josh Ryor, principal for the Northeast region at RAP.

Some regulators have begun to reward the outcome instead. State utility commissions are adopting affordability metrics within performance-based ratemaking frameworks to financially incentivize utilities to encourage affordable customer bills, said Emily Apadula, a senior policy analyst at the NC Clean Energy Technology Center. Illinois ties utility earnings to as many as seven performance metrics, including peak load reductions, McCabe said.

Regulators can also let utilities capitalize multi-year digital contracts, which narrows the gap between software and steel. There is a precedent in Germany: when Avacon buys software for a multi-year term, for example five years, the German regulator and corporate finance departments accept capitalizing it, Hintz reported.

WHAT TO DO

- **Regulators:** Tie part of utility earnings to outcomes such as affordability and peak load reduction. Illinois uses as many as seven performance metrics.
- **Regulators:** Let utilities capitalize multi-year software contracts. Germany's regulator accepts this for Avacon.

Get Help to the Customers Who Qualify

Event Themes: Rate Design & Cost Causation · Customer Agency & Safeguards

Multi-tier income-qualified discounts, tied to state median income, can be paired with arrearage relief. Portland General Electric has done both. Its income-qualified discount is now a five-tier program based on income relative to state median income, with relief of up to 80% on customer bills, and a new arrearage relief program gives customers in the top two tiers up to $500 of relief a year, reported Jaki Ferchland, senior manager of pricing, tariff, and cost recovery at PGE.

Enrollment is the gap. In Connecticut, 31% of residential customers are income-eligible for utility discount rates and only 17% are enrolled in available assistance programs, reported Kristina Kelly, vice president of energy risk, strategy, and markets at DNV.

CONNECTICUT: ELIGIBLE FOR A DISCOUNTED RATE VERSUS ENROLLED



Source: Kristina Kelly, DNV. One state; share of residential customers.

Other customers have a stake in closing it, because unpaid bills come back as higher rates for everyone. Connecticut's Office of Consumer Counsel estimated that about $70 million of 2024 rate increases came from uncollectible arrearage balances, Kelly said, and higher rates in turn produce more arrears.

WHAT TO DO

- **Utilities:** Offer income-tiered discounts tied to state median income. PGE runs five tiers with relief of up to 80%.
- **Utilities:** Add arrearage relief. PGE's new program gives up to $500 a year to customers in its top two tiers.
- **Utilities and regulators:** Enroll the customers who already qualify. In Connecticut, 31% are eligible and 17% are enrolled.

Still Open

Four questions were left open, and each one decides who ends up paying.

Who carries the cost of load that does not arrive? PJM's 80 GW could be 80, 40, or 20. Assigning upgrade costs to the loads that need them answers part of it. What happens to infrastructure built on a forecast that proves wrong was not answered.

Do time-varying rates help or hurt the households with the least room? One speaker warned that a $50 swing forces a choice between bills. Another watched low-income customers ask to stay on a demand rate. One pilot and one default tariff do not settle it.

How much safety is enough? If shutoffs and fast-trip settings have already cut ignition risk by 60 to 70%, someone has to decide what the next dollar of risk reduction is worth and defend that number in public.

Will utilities be paid to spend less? As long as a dollar of steel earns four times the return of a dollar of software, the cheaper option is the one a utility is paid least to choose. Germany's treatment of software contracts and the first performance metrics are early signs. Neither is yet the rule.

Each of these questions can be put to a reader's own utility or commission. The answers will be worth comparing when the industry gathers for GridFWD 2027 in Tucson.

About this synthesis. Prepared for Grid Forward by Corey Balgeman of Grid Flexibility (gridflexibility.fyi). It was drafted with AI assistance from transcripts of 29 recorded GridFWD 2026 sessions. Each sourced statement and speaker was then checked by ear against the recordings.

