Integrated Distribution System Planning

NASEO and NARUC Webinar

July 13, 2025

Energy+Environmental Economics

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Who is Energy and Environmental Economics (E3)?

Technical and Strategic Consulting Firm

~150 full-time consultants | 30 years of deep expertise | Engineering, Economics, Mathematics, Public Policy…….


San Francisco


New York


Boston

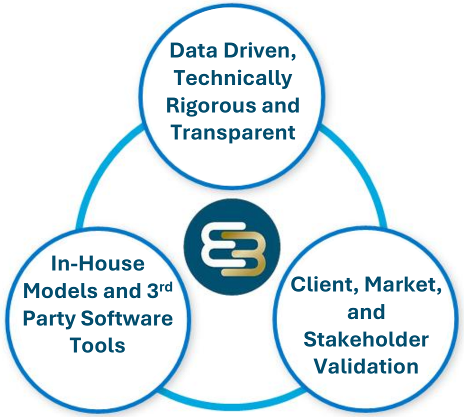

Chicago


Calgary


Denver

E3 is Project and Expertise Driven with a Diverse Client Base

400+ projects per year for over 150+clients



Public & Non-Profit Sector
- Planning agencies and non-profits
- Regulators and commissions

Utilities & System Operators
- Investor and publicly owned utilities
- ISOs/RTOs and other system operators

Investors & Project Developers / Owners
- Asset owners and project developers
- Investors and financiers

Why We Are Talking About Distribution

- Utility rates are rising nationwide
- Distribution is the largest and fastest-growing cost category.
- Rate-base regulation rewards utilities for building distribution infrastructure
- DER can defer distribution investment

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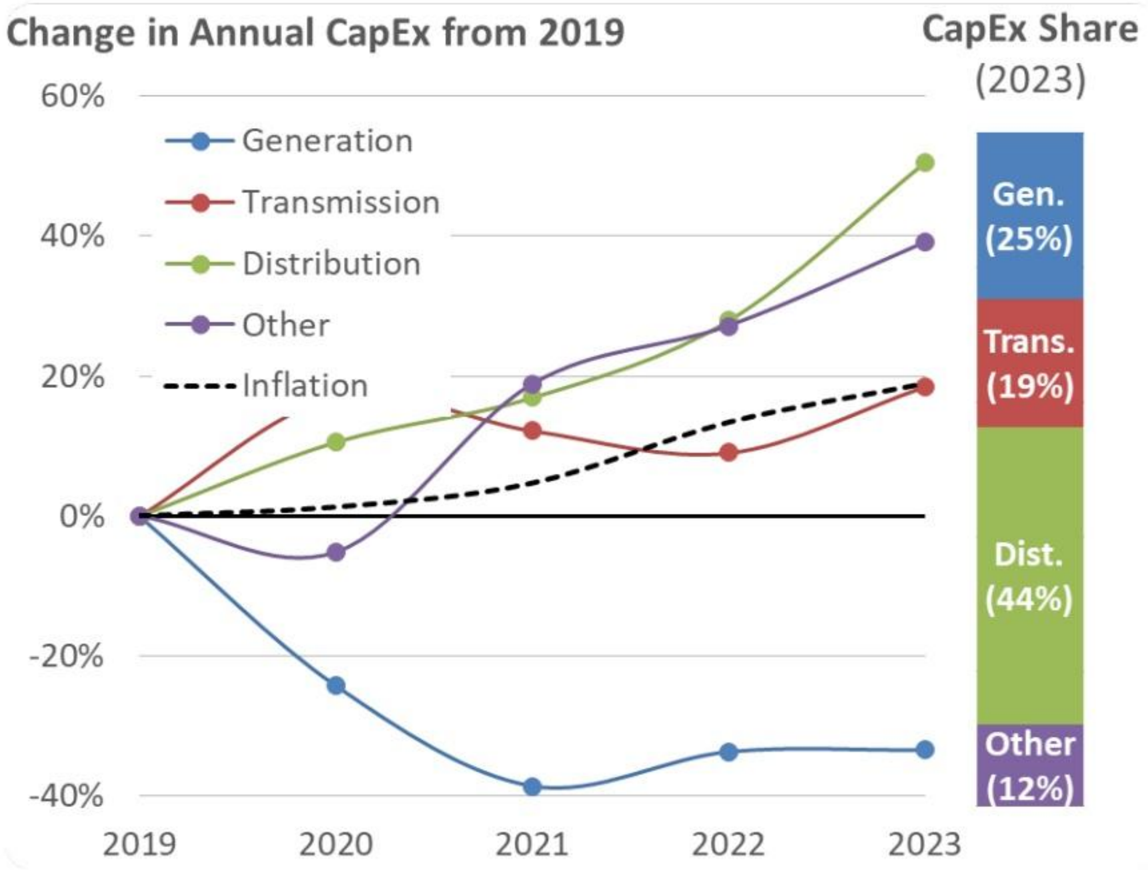
More DER will lower distribution costs and rates



Retail Electricity Price and Cost Trends: 2024 Update | Energy Markets & Policy

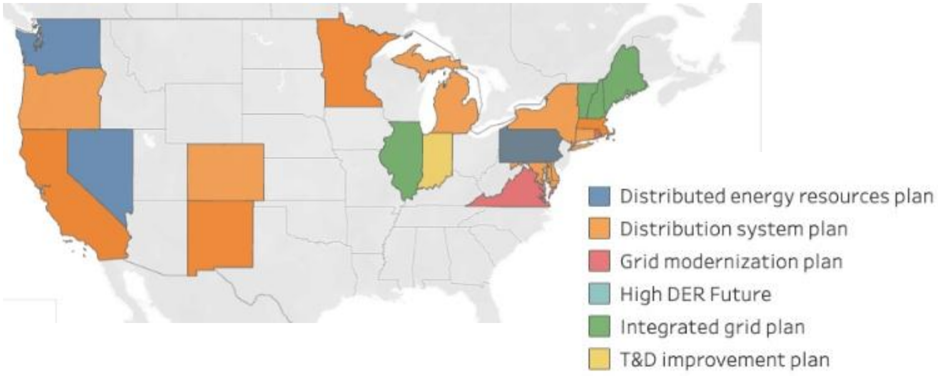
Integrated Distribution System Planning (IDSP) Opportunity

Common Requirements

- Scenario Analysis
- Longer-term planning
- Multi-objective prioritization & alignment with state goals
- Increased transparency and stakeholder involvement
- Integration of DER & evaluation of alternative investment options
- Robust cost-effectiveness analysis
- Justifying prioritization & timing of investments

22 states have updated distribution planning requirements

LBNL



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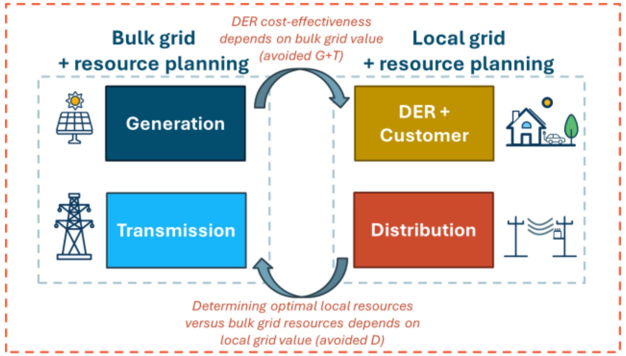

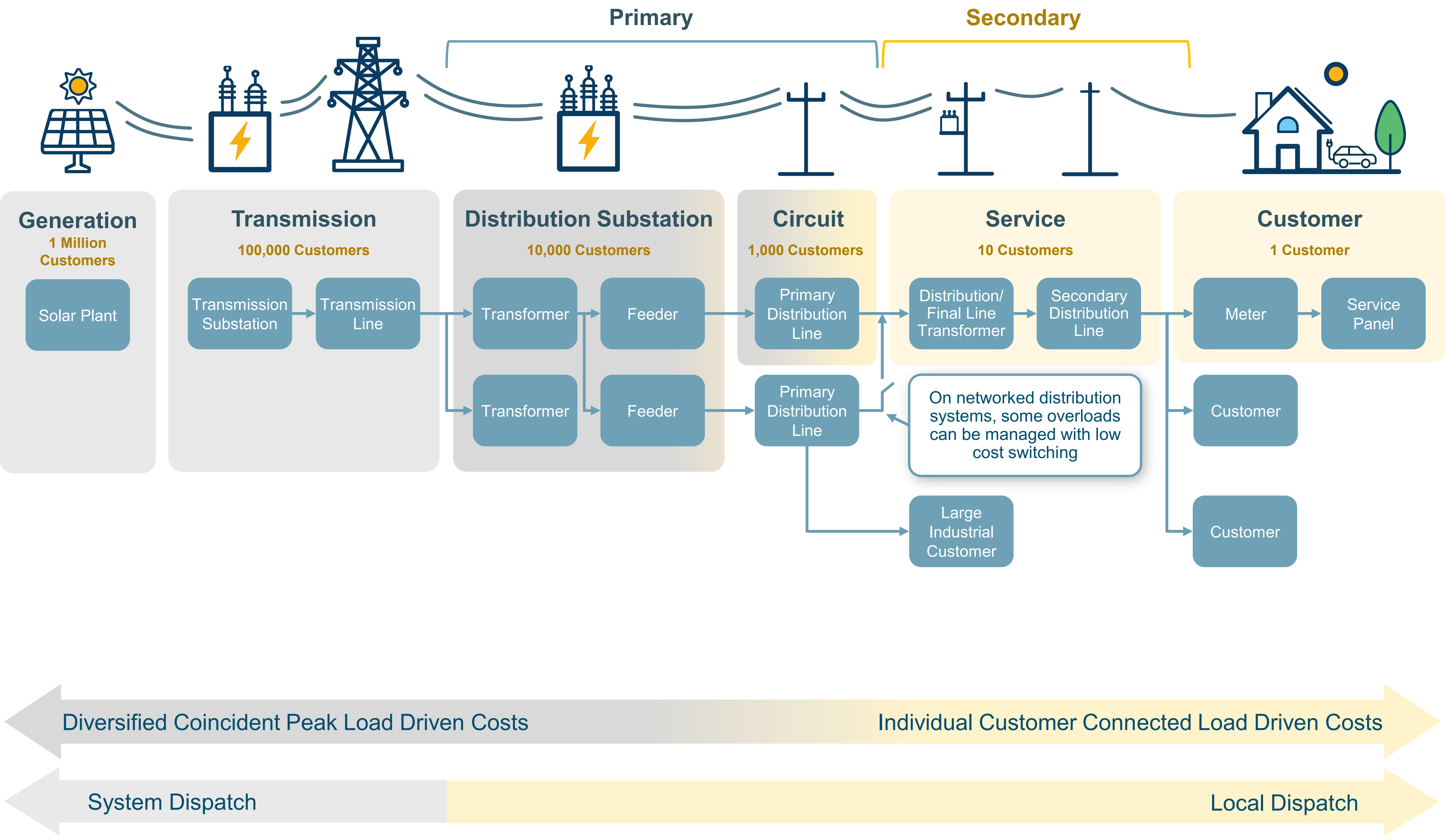

Primary
Secondary
Generation
1 Million Customers
Solar Plant
Transmission
100,000 Customers
Transmission Substation
Transmission Line
Distribution Substation
10,000 Customers
Transformer
Feeder
Transformer
Feeder
Circuit
1,000 Customers
Primary Distribution Line
Primary Distribution Line
Service
10 Customers
Distribution/ Final Line Transformer
Secondary Distribution Line
On networked distribution systems, some overloads can be managed with low cost switching
Large Industrial Customer
Customer
1 Customer
Meter
Service Panel
Customer
Customer
Diversified Coincident Peak Load Driven Costs
Individual Customer Connected Load Driven Costs
System Dispatch
Local Dispatch

Into the Weeds: Marginal vs. Avoided Distribution Costs

	Category	Example costs	Cost Driver	Average	Marginal	Avoided
Non-Marginal Non-Load Related Costs	Embedded/Sunk	Existing Substation		✓		
	Age Related Replacement	Replace Aging Transformer		✓		
Marginal Costs	Marginal Distribution Capacity (Primary)	Substations, Primary Feeders	**Coincident peak load**	✓	✓	✓
	Marginal Distribution Capacity (Secondary)	Secondary Feeders Final Line/Service Transformers	**Non-coincident Connected Load**	✓	✓	✓*
	New Business & Line Extension	Line extensions, service laterals, new customer interconnections	**Number of customers (by type/size)**	✓	✓	
	Customer Access - Connection Equipment	Service drop, meter	**Number of customers (by type/size)**	✓	✓	
	Customer Access - Customer Service	meter reading, billing, communications	**Number of customers**	✓	✓	

** Avoiding secondary capacity costs relies on reducing non-coincident peak and connected load among a small number of customers, which is more challenging than reducing coincident peak load on the primary distribution system.*

Making it Work: Considerations for Implementation

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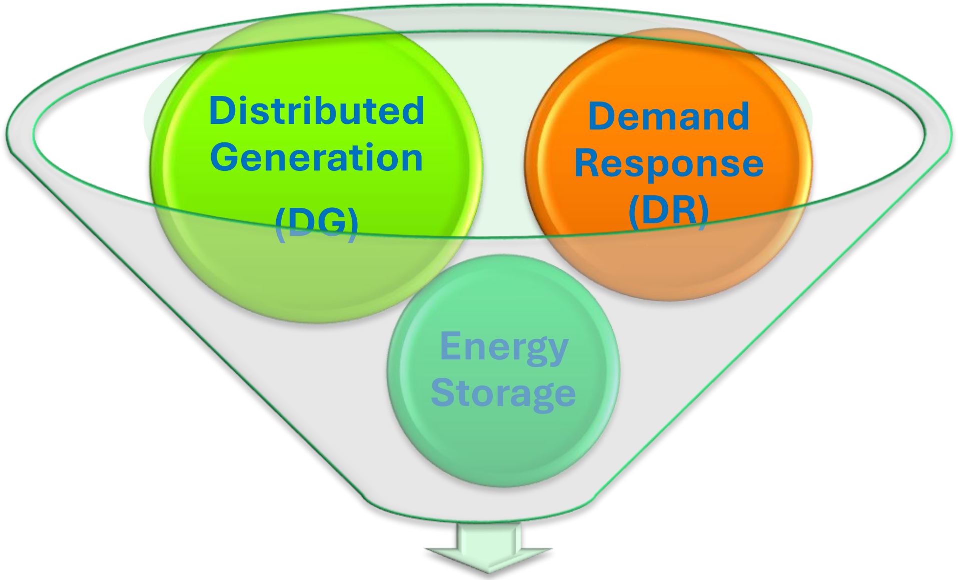
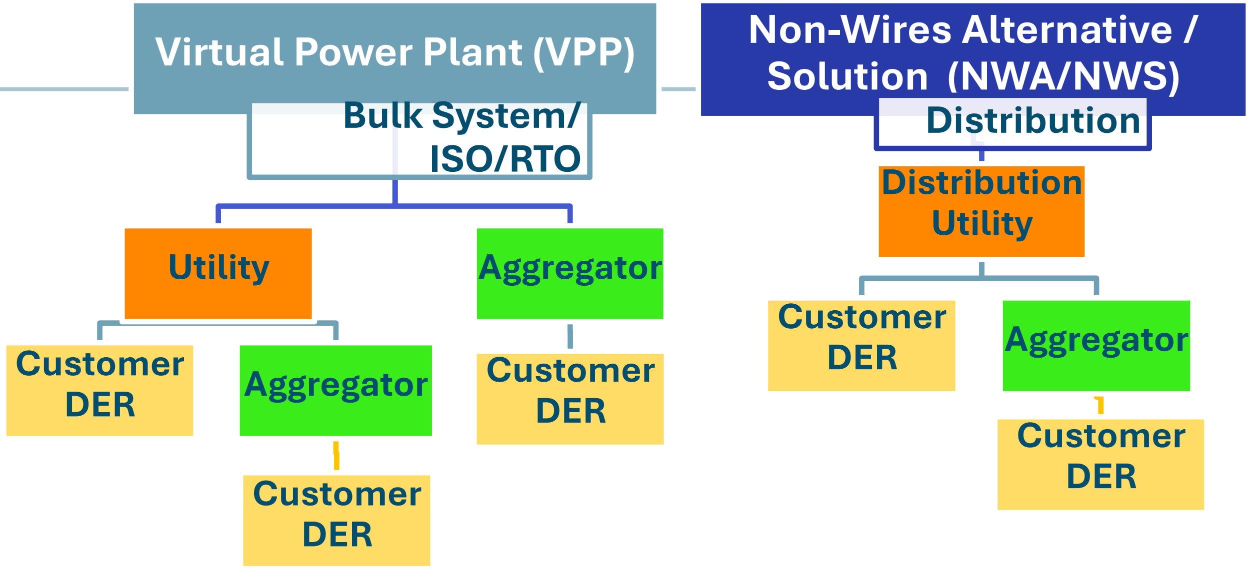
Definitions For Discussion





Distributed Energy Resources

- Energy storage can import or export energy
- Functionally, EVs can function as a DR resource or as an energy storage resource with V2G

+ **Flexible Resources**
  - **Flexible Interconnection** – Interconnect distributed generation with nameplate exceeding hosting capacity but ability to curtail output.
    - (Initially scheduled, eventually dispatched)
  - **Flexible Load** -> see DR as DER

+ **VPP or NWA** – Routine utilization of DER to provide grid services
+ **Orchestration** – monitoring and utilization of DER in real-time
+ **Demand Response as a DER**
  - ***Increase or decrease*** in electricity demand in response to a price or dispatch signal
  - **Legacy DR –** Limited use to maintain reliability of system, implemented as a contingency (e.g. peak shaving), or market price mitigation.
  - **Flexible Load** – Routine use of DR to provide grid services – primarily capacity

Perceived Utility Capabilities and Sophistication vs. Current Maturity

	Distribution Planning	Distribution Operations	Distribution Automation (DA)	DER Resources
Today	• Focus on peak days • Limited data from substation SCADA and AMI • Multiple tools to perform an increasing variety of analysis	• SCADA visibility and control at Substation • Inaccuracies in distribution GIS network model	• Autonomous controls (reclosers, fuses, voltage regulators) • Advanced Metering Infrastructure (AMI) outage notifications (underutilized)	• Old direct load control programs and technology • Rely on 3rd party aggregators with proprietary solutions • Limited operational integration
Tomorrow	• Focus on monthly variability of both loads and distributed generation • Additional data from DA sensors • Tool integration to perform multivariable simulations with a range of possible outcomes	• Advanced Distribution Management System (ADMS) • Distributed Energy Resource Management System (DERMS) • “Digital Twin” connectivity model	• DA devices provide monitoring and control to distribution operator with ADMS • AMI power quality and anomality notifications	• DERMS interface to utility scale DER (3rd party or utility) • DERMS interface to aggregated customer DER (aggregator or customer) • Telecom & messaging protocol standard adoption

What is needed to use DER to provide Distribution Grid Services?

Customer DER Program design (and regulatory approval)

- Rules for DER utilization (dispatch) of participating customer DER resources

DER aggregation point(s)

- system, > 24 kV substation, < 24 kV Substation, Circuit/Feeder, or groupings/aggregations of these

Customer incentive / compensation (tied to value of resource)

- Can be derived from and supported by an economic analysis
- Account for costs of both enabling and managing the customer DER program

Customer Enrollment (propensity)

- Need enough enrollment to make the DER aggregation a viable resource

Enabling Technology

- Customer Device
  - Programs should be organized by *grid services*, not by technology… and most programs are grouped by tech
- End use device interface
  - Telecommunication Pathway
  - DER Messaging Protocol
- Operational System Integration (e.g., ADMS, DERMS, GIS, CIS, etc.)

DER Program management (utility or aggregator)

- Customer interfaces, manage enrollment and unenrollment, troubleshoot and maintain technology

DER Grid Services

DER Grid Services	Bulk System	Distribution
Capacity	Virtual Power Plants (VPPs) utilizing DER for the bulk electric system	Non-Wired Alternatives (NWA) providing Grid Services for specific areas of the distribution grid
Hosting Capacity		Flexible Interconnection & Flexible Load
Voltage Support		IEEE 1547-2018 advanced inverter Volt-VAR, and Volt-Watt controls Flexible load orchestration?
Frequency	IEEE 1547-2018 frequency provisions for inverter-based resources (IBR)	
Inertia	Today: "grid following" IBR rely on the voltage waveform from the grid to synchronize their output. Future: "grid forming" IBR can help support inertia needs with voltage injection	

Maturity Stack for DR and DER Sophistication

TODAY

7) ADMS - DERMS Integration

- ADMS identifies grid need. DERMS presents available grid services. ADMS dispatches DER grid services in real-time to provide grid services.
- **Enable progression from scheduled use of DER to real-time orchestration**

6) DERMS

- DER monitoring, management, dispatch, and performance evaluation
- Utility DERMS can interact with 3rd party “edge” DERMS

5) DER Participation in ISO/RTO (FERC Order 2222)

- Utility or 3rd party provider can bid in an aggregation
- Many ISO/RTO tariff updates are pending or have future implementation dates.

4) Storage participation in ISO/RTO (FERC Order 841)

- Utility or 3rd party provider can bid in an aggregation
- Measurement & verification can be difficult
- Dual-participation (market and distribution) is a challenge

3) DR Participation in ISO/RTO Market (FERC Order 719 & 745)

- Utility or 3rd party provider can bid in an aggregation
- Performance of DR dispatch is still a struggle
- Need better performance measurement & verification

2) Basic Non-Wired Alternative (NWA) / Virtual Power Plant (VPP)

- Scheduled a day ahead based on weather forecast or day-ahead market price
- Uses one or multiple DER aggregators

1) Legacy Reliability Demand Response

- Curtailment of specific loads from customers participating in a DR program (<12x/yr for peak/contingency)

Distribution Grid Constraint Mitigation Options

Cost

New Substation	Major capacity expansion; highest cost, longest lead time
Substation Capacity Increase	Expand existing station capacity before building entirely new infrastructure
New Feeder/Circuit	Add a new feeder to move load off a constrained feeder and create more carrying capacity
Targeted Capital Project	Smaller, scoped infrastructure project to address a localized issue *Examples: Reconductoring, Service Transformer Upgrades*
Operational / NWA	Operational and non-wires measures that address constraints more quickly and more selectively *Examples: DFR with Phase Balancing, Load Shift, Demand Flexibility, Distributed Energy Storage, Dispatched DG*

- NWA Screening Criteria for Technical Feasibility
- Financial feasibility compared to infrastructure

PG&E Electrification Impact Study

https://www.ethree.com/webinar-pge-eis/

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PG&E EIS Key Findings

- Electrification requires ~$23B to ~$31B in distribution investment by 2040, in line with current investment trends
- Enhanced orchestrated demand flexibility can reduce peak demand by 2.2 GW and reduce distribution costs by $1.8 Billion (7%)
- Secondary distribution costs account for 58% of total costs, majority for serving new development and not avoided by load management
- Electrification growth may provide downward pressure on rates by as much as 25% by 2040 with well orchestrated load management
- Distribution constraints becoming more local, seasonal and less aligned with bulk system peak
- Distribution system average load factor is 69% in 2040, with 500 feeders above an 80% load factor

Methodology - *Forecasting Workflow*

Forecasting Anywhere

Scenario-based generation of technical potentials, propensities, and adoption forecasts at H3 level

- IEPR Load Forecast → Disaggregated by charger type or end use → Adoption Forecast
- Geospatial Datasets → Machine learning and heuristics → Propensities; Technical Potential

Load Shapes

- **BE load shapes** from NREL's *ResStock* and *ComStock*
- **EV charging load shapes** generated from E3's *EVLST*
- **PV, Storage, EE load shapes** are directly from *IEPR*

LoadSEER

Distribution planning tool used by PG&E for secondary load impacts, siting and sizing

1. Map H3 to Premise
2. Spatial Allocation
3. Load Impacts
4. Secondary Capacity Planning

CYME

Power flow model used by PG&E for distribution planning at the feeder level

1. Primary Conductor Loading and Voltage
2. Load Flow Model with Service Point Level Forecasting
3. Integrated Known Loads
4. Integrated GNA Capacity Solutions

Methodology - *Scenarios*

E3, IA, and PG&E analyzed three main scenarios to determine potential distribution costs

	Scenario	Description
1	Base Scenario	**BAU adoption** of electrification (EVs; heat pumps) and DERs (solar; storage)
2	Equity Scenario	**Additional adoption** encouraged in priority communities
3	Load Management Scenario	**Implementation of load flexibility** to mitigate some distribution upgrades

Equity scenario modeled **more** adoption of electrification + DERs

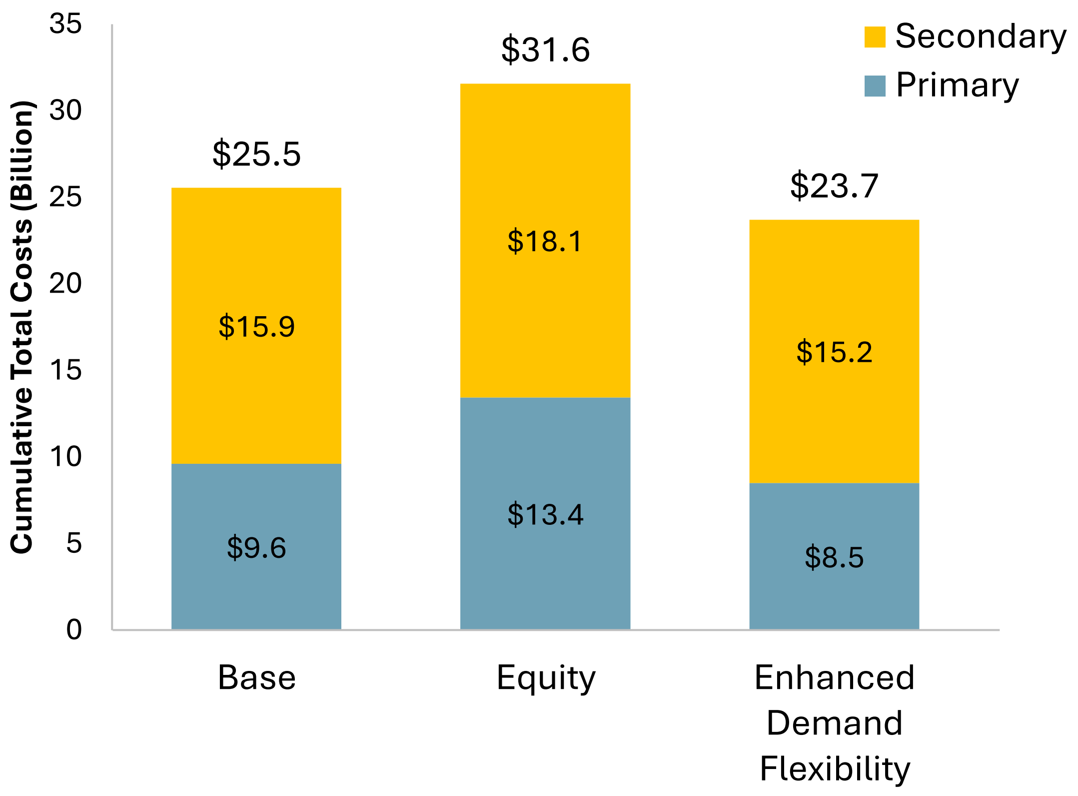
Higher costs on distribution system

Load management scenario showed how **flexible technologies** can help mitigate distribution cost impacts

PG&E EIS Study found majority of distribution costs on secondary system

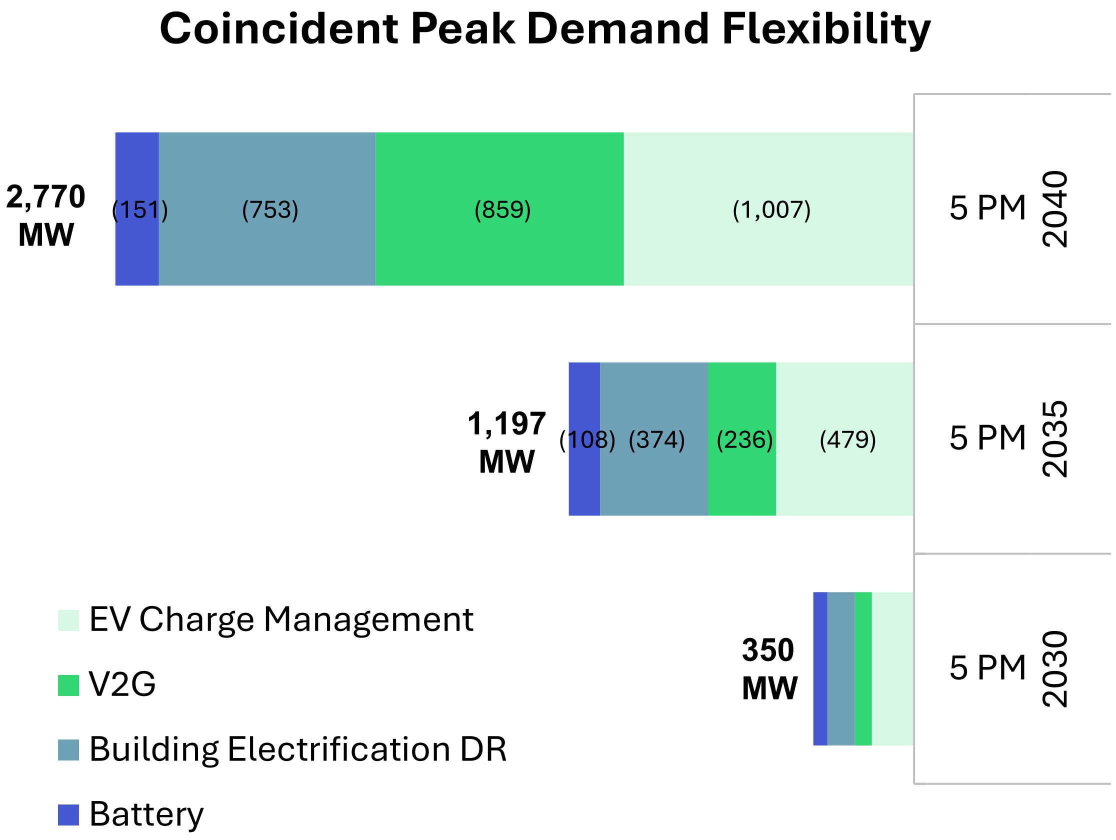
- Enhanced orchestrated demand flexibility can reduce peak demand by 2.2 GW and reduce distribution costs by $1.8 Billion (7%)
- Secondary costs for energization are ~62% of total distribution infrastructure costs
- Secondary costs are not avoided with coincident peak load reductions from flexible load
- Distribution constraints becoming more local, seasonal and less aligned with bulk system peak

Distribution Primary and Secondary Costs by Scenario



Enhanced Demand Flexibility Scenario

+ **The Base Scenario includes business-as-usual demand flexibility, including passive managed charging (TOU rates)**
+ **The Enhanced Demand Flexibility Scenario applies incremental technology specific managed load, benchmarked to the CEC's D-Flex tool**
+ **EV Charge Management + V2G**
  - Increased charge management participation, introduces more active charge management to feeder-specific needs, and vehicle-to-grid (V2G)
+ **Building Electrification Demand Response (DR)**
  - Model shed + shift DR events based on LBNL CA DR Potential Study
+ **Battery**
  - Increased utilization of storage for enhanced demand flex

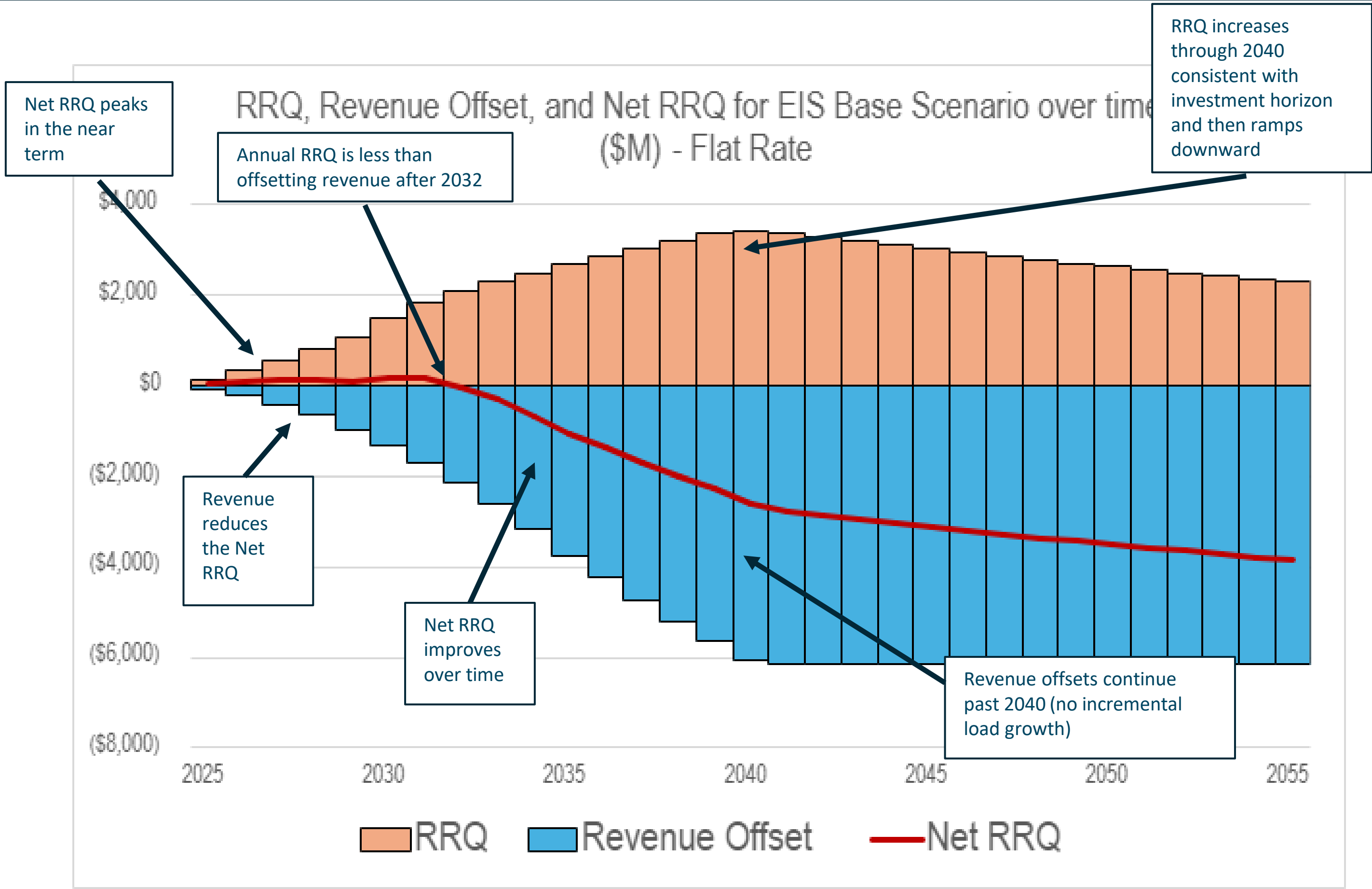


Preliminary Analysis shows significant downward pressure on Distribution Rates over time

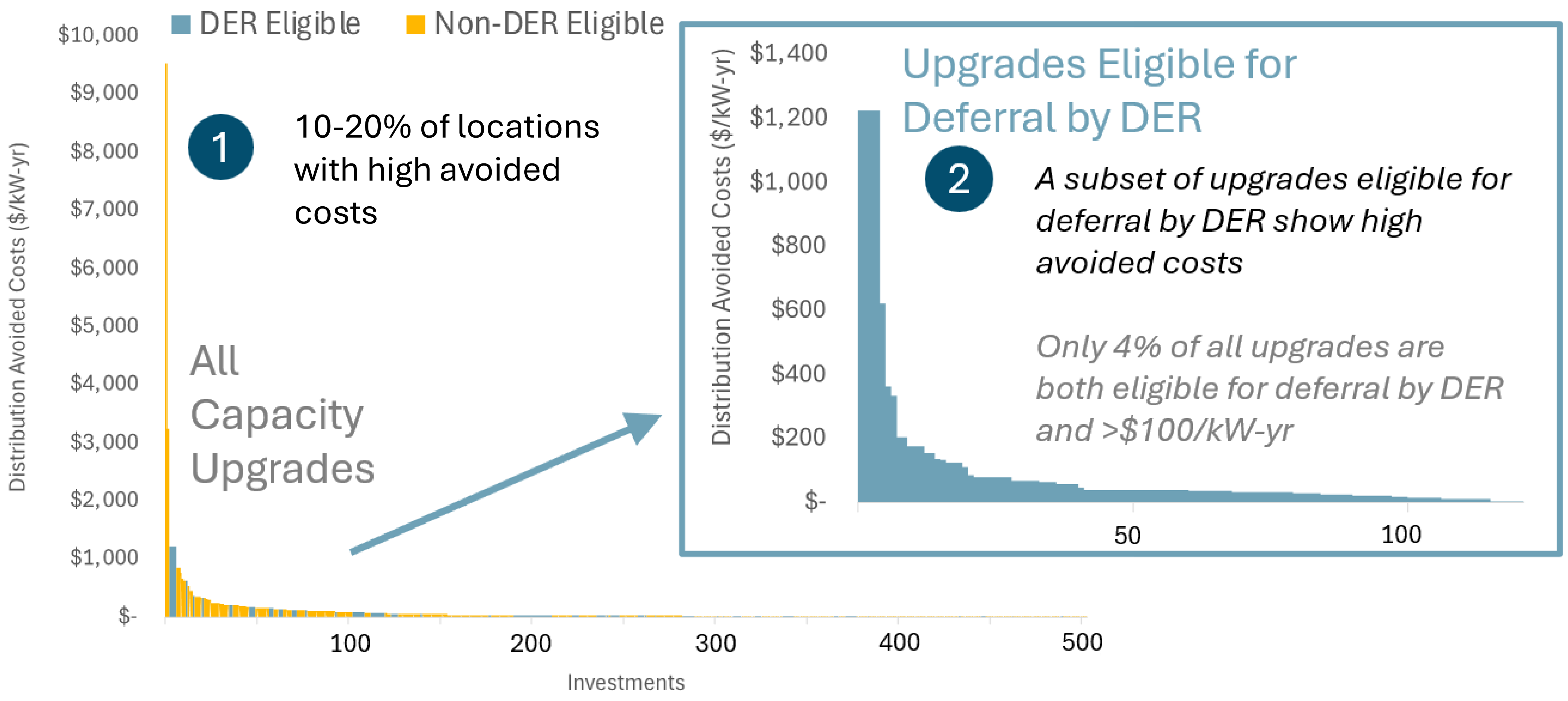
All scenarios show a long-term downward pressure on distribution rates from energization investments that drive electrification growth.

Year	*2030*	*2035*	*2040*
Annual Revenue Requirement (RRQ) [$B]	**$1.5**	**$2.7**	**$3.4**
Annual Offsetting Revenue [$B]	**$1.3**	**$3.7**	**$6.1**
Net Annual RRQ [$B]	**$0.2**	**($1.1)**	**($2.6)**
Rate Pressure (%)	**1.6%**	**(10%)**	**(25%)**
Net Present Value (NPV) [$B]	**$14.2**		

- Near-term rate increases due to capital outlays are offset by sustained revenue growth from increased energization, indicating long-term value of energization investments.
- Net Present Value of Energization of $14.2B, showing a small upward rate pressure in the near term followed by downward distribution rate pressure from 2031 onwards.
- Costs are ***solely*** for Distribution Energization Investments and does not include other incremental costs (e.g., safety, reliability, etc.). This is not a rate forecast.



Distribution Deferral Opportunity for DER is Targeted



Compensating DER for Local Distribution Value (LVDER)

https://www.ethree.com/lvder-whitepaper/

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DER Reality: Too Complex to Scale - Too Uncertain to Plan

Dream

Unlock latent potential of DER and flexible loads for grid services at lower cost

Reality

Overcompensation

Participation Barriers

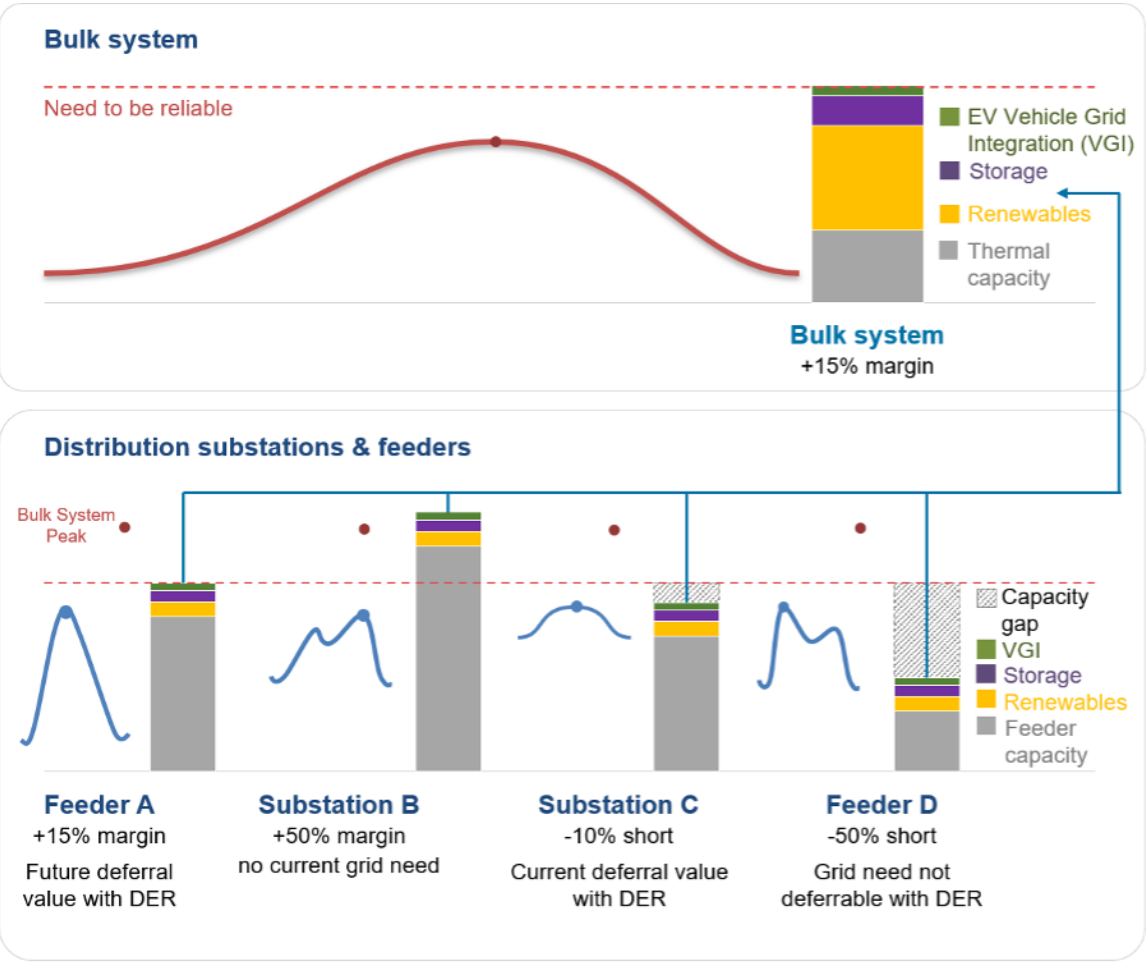
Gaming Baseline

Under-performance

Cost-shift

Distribution Capacity Value is Harder Than Bulk System Capacity

- **The need sits at small subset of selected feeders**
- **Peaks in hours that differ across the system**
- **Calls for only the discrete reduction that defers a planned upgrade**
- **Value lasts only until that upgrade is built.**
- **Dx – Effective Load Carrying Capacity**
  - **Coincidence:** whether the resource's output aligns with the hours the local feeder peaks
  - **Availability:** how much of the enrolled resource shows up when called, given opt-outs, dispatch fatigue, and the customer's own use
  - **Duration**: whether it can sustain its output for the entire time it is needed, from a multi-hour feeder peak to a multi-day heat wave



DER are first and foremost a customer asset

Using DERs for locational grid services presents unique challenges as compared to utilizing DERs for bulk system services

Load Flexibility for **Generation Capacity**

- Resource procurement team reevaluates load growth and generation capacity contracts on **an ongoing basis**
- If program participation does not meet expectations, **shortfalls in capacity can typically be made up through a liquid market** for short-term contracts
- **Larger pool of participants** dampens impacts of single individuals opting out for a season

Load Flexibility for **Locational Capacity**

- Distribution planning teams plan capital projects over **multi-year cycles**
- If program participation does not meet expectations, **backup options to avoid capacity exceedance are more physical in nature** (e.g., diesel generators, mobile batteries), if available at all
- Not all customers will be eligible to participate in locational capacity programs. Relying upon a **smaller pool of participants** at a specific location with a grid need increases impact of any single individual opting out

Distribution capacity deferral is a multi-year commitment: **achieving sufficient/reliable capacity through programs is paramount**

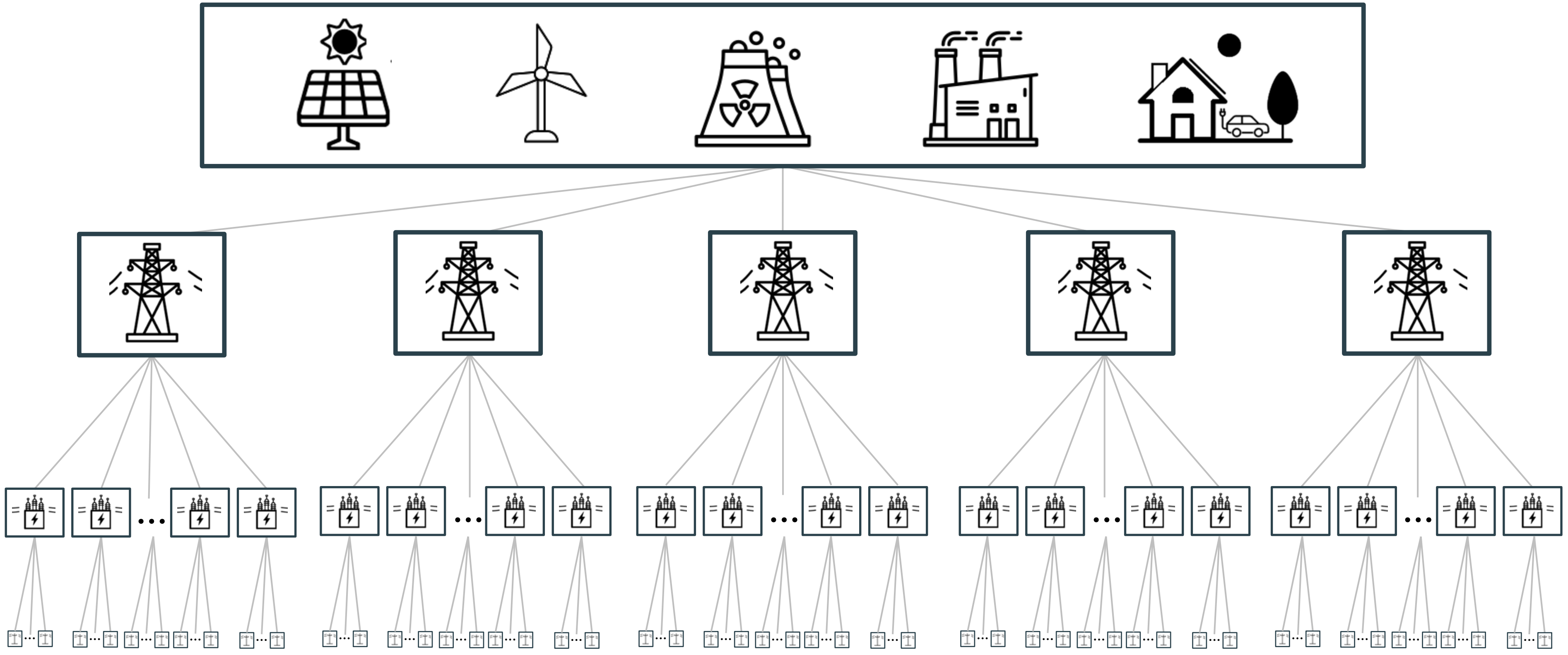
Computational challenges: there are tradeoffs between computational tractability and spatial granularity

1 system

10s of Tx zones

100s of Dx substations

1000s of Dx feeders



Diversified coincident peak load

Increasing spatial granularity

Individual connected non-coincident peak load

Key challenge: It is computationally intractable in a system-wide optimization to capture detailed distribution level constraints and solutions (e.g., 1000s of candidate storage options)

Sourcing mechanisms matter for appropriateness to provide locational capacity

Utility ownership + control	Competitive Solicitations	Customer Programs	Tariffs
Utility self-builds with direct operational control for specific grid needs (e.g., non-wires alternatives)	**Utility driven procurement for may be targeted** (e.g., location and attribute specific non-wires alternative) **or all-source** (e.g., generation or capacity) RFOs	**Utility (or third party) programs using incentives, marketing, and education** to facilitate customer DER adoption **for "cost-effective" DERs**	**Customer adoption or behavioral change driven by price signals** such as retail rate design, net metering/billing, feed-in-tariffs, etc.

Performance Risk / Development Risk

Lowest	Lower	Medium	High

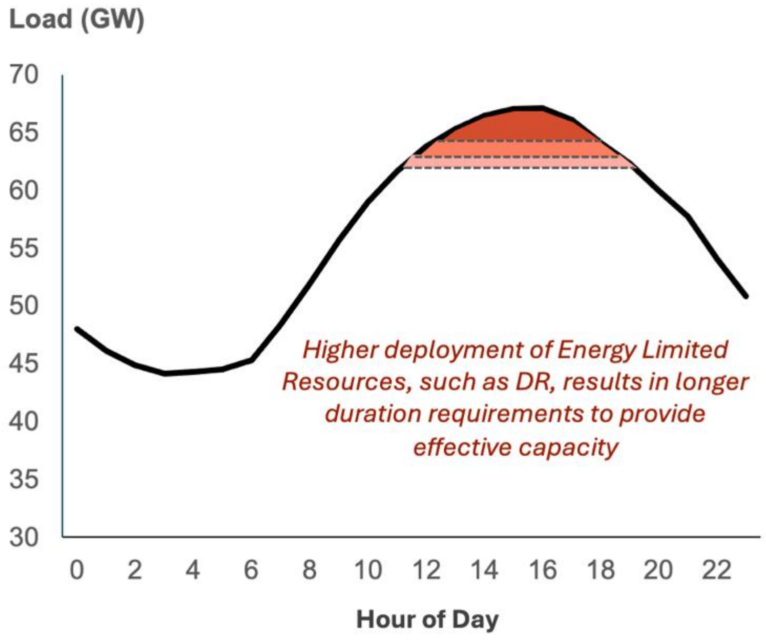
Suitable to Provide Locational Capacity

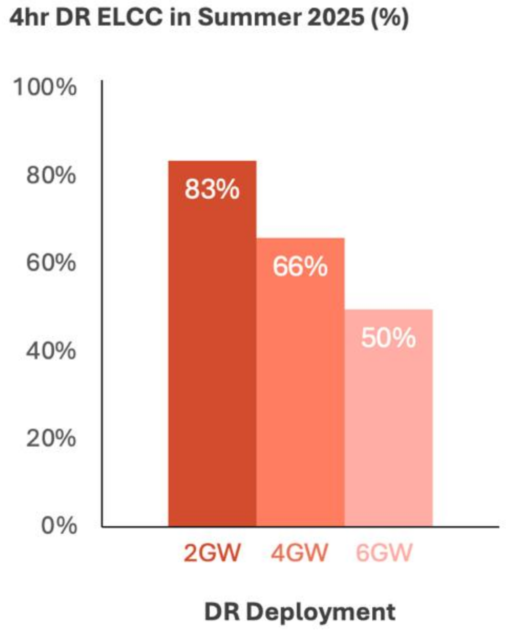
Yes	Yes	Maybe	No

* Some customer programs are planned in aggregate to achieve a cost-effective portfolio, which includes highly cost-effective measures offsetting lower cost-effective measures that may fill additional objectives (equity, market transformation). Least-cost optimization tends to select only highly cost-effective measures.

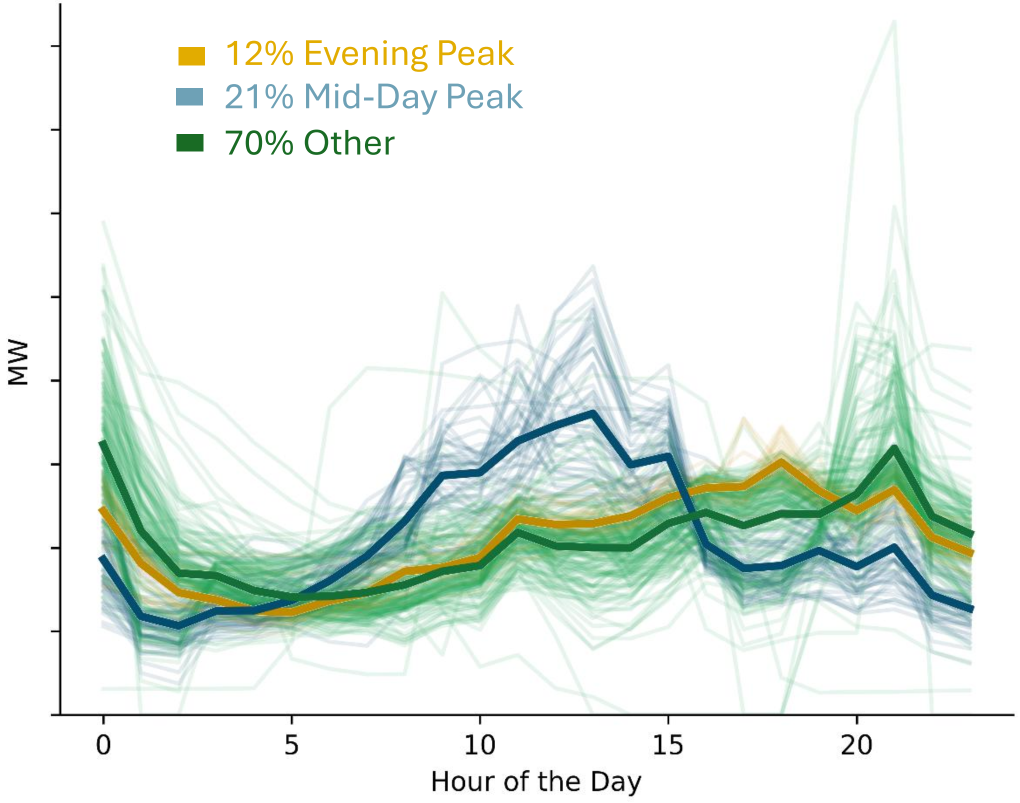
Important Concepts for Distribution Value

Declining Effective Capacity





Diversity of Peak Load Shapes



Program Design That Overcompensates for Distribution Value

- Marginal rather than avoided costs as a basis for compensation
- System-wide rather than targeted compensation focused on feeders with identified needs
- Bulk-system-based dispatch windows rather than dispatch based on local feeder conditions
- Enrolled rather than effective capacity-based compensation
- Long commitment terms that lock these structures in, even as grid conditions change

Principles for LVDER Program Design to Reduce Rates

+ Compensate below the avoided cost

- Anchor to avoided not marginal cost.
- Two tiers: system-wide plus a targeted locational payment.
- Incremental to retail rates.

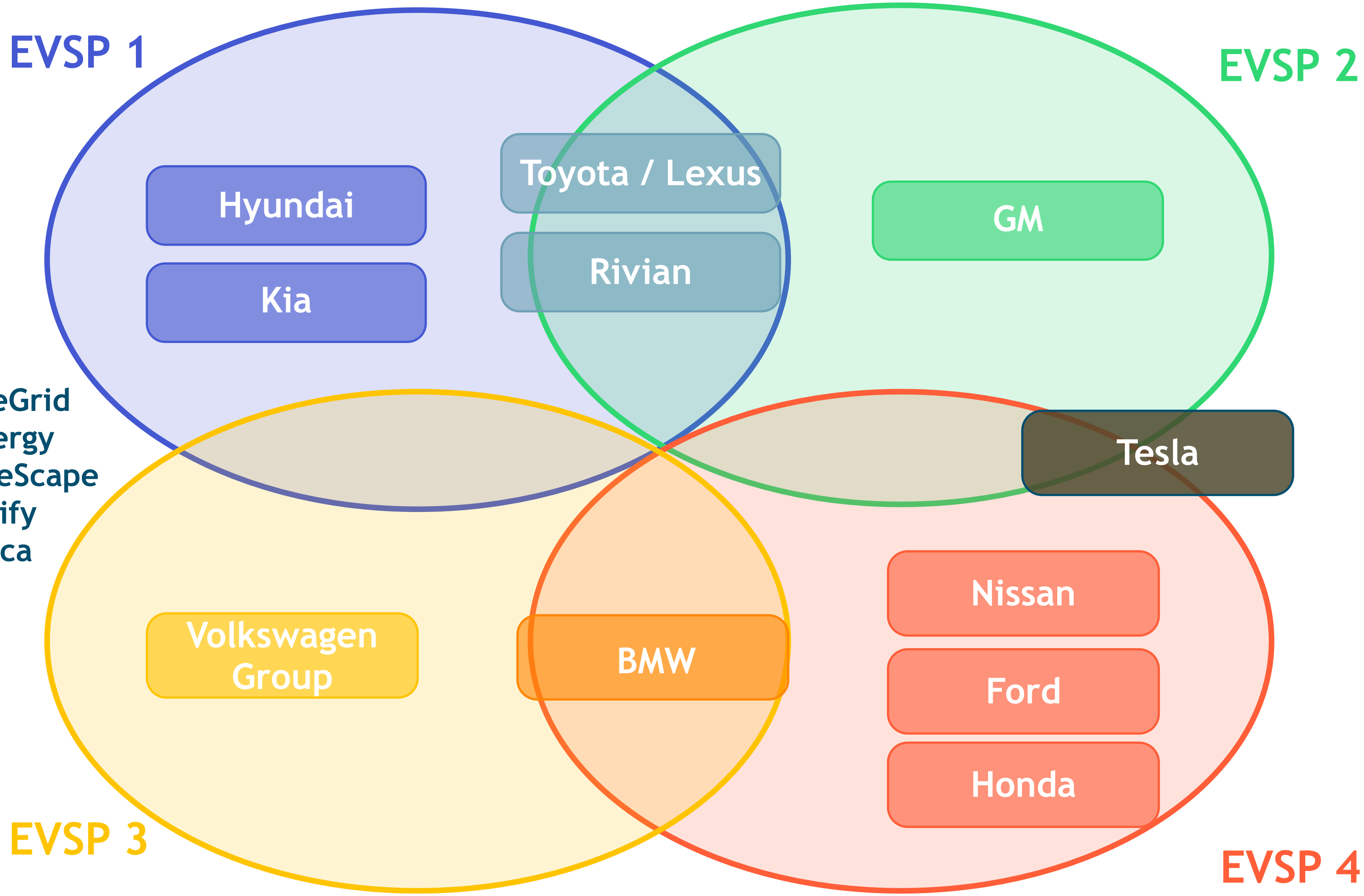
+ Pay for measured performance, not enrollment.

- Locations with a deferrable need with capped quantity
- Dispatch to local, not bulk-system conditions.
- Pay for effective capacity during critical hours.

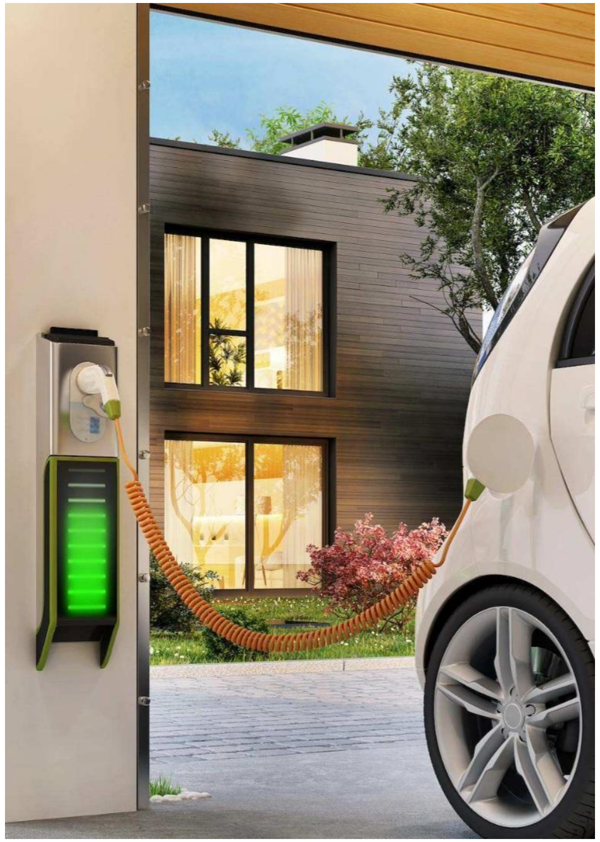
+ Streamline and consolidate programs.

- Interoperable, open standards and APIs.
- Co-optimize services, directed to their highest-value use.
- Balance enrollment and performance risk.

EVs as a Case Study in Lack of Interoperability



EVSPs
- WeaveGrid
- ev.energy
- ChargeScape
- Electrify America



EVSP: Electric Vehicle Service Provider

Summary Table In Paper

Program (status)	System-wide payment	Sys. basis	Locational payment	Loc. basis	Set by	Revision trigger	Dispatch window	Compensation basis	Commitment term
Illinois **CRGA VPP & DG rebate** **(P.A. 104-0458, sec.16-107.6/.9)** **2026-2028**	$300/kW DG & $300/kWh storage now, stepping to $250 after 2029 +$10/kW-avg-dispatch floor	Administrative	authorized for additive services / VPP tariff (sec.16-107.9) amounts TBD	TBD	Legislation Regulator	Statutory defined “Threshold Date” will occur in 2028 transitioning to ICC based formula	Fixed statutory 4-6 pm BTM 4-7 pm FOM weekdays Jun-Sep (PJM peak)	Enrolled MW + performance ($/kW avg dispatch)	5-yr enrollment (re-enrollable)
New York **VDER DRV/LSRV (PSC Case 15-E-0751)** **in effect**	DRV per utility $/kW-yr	Marginal cost	Yes (LSRV) per-utility adder at designated substations finite MW per zone	Marginal cost	Regulator Utility tariffs	10-yr vintage lock; updates with PSC-approved MCOS studies	Fixed bulk-peak window Varies by utility	Metered kWh exports (performance)	10-yr vintage lock
Connecticut **Energy Storage Solutions** **(PURA 25-08-05)** **in effect (Apr 2026)**	Enroll $30/kWh res, $10/kWh priority comm; perf (fixed 10 yr) $300 std / $450 underserved / $550 low-income per kW-yr	(basis not stated)	Yes $130/kWh residential grid-edge enrollment incentive	Administrative (basis not stated)	Regulator Utility proposal	PURA docket	Event-based 30-60 summer 1-10 winter	Enrolled MW + performance payment	10 years
Colorado **Aggregator VPP** **(SB 24-218; CPUC 25A-0061E)** **in effect (Dec 2025)**	Gen $134 + trans $21 /kW-yr; aggregate ~$264.56/kW Yr1 (incl. distribution)	Avoided cost (Year 2 market-indexed)	Yes distribution $69/kW-yr in DSP-constrained (>75% planning limit) areas	Avoided cost (DSP feeders/ banks)	Legislation Regulator Utility Filing	5-yr fixed then reset; Yr2 market-indexed	Flexible, year-round 60 (summer-only) 80 (year-round) 4-hr events	Measured baseline-vs-actual	5 years
Hawaii **Battery Bonus; BYOD** **(PUC 2019-0323)** **in effect**	Battery Bonus $850/kW upfront + $5/kW-mo BYOD L1 $100/kW BYOD+ $400 (non-LMI)/$800 (LMI) per kW	Administrative	No	(basis not stated)	Regulator Utility Filing	MW caps BB 55 MW BYOD 50 MW, 25 LMI + set timelines	Scheduled BB: 6:00-8:30 pm BYOD: 2 hr/day	BB: Firm scheduled capacity BYOD: upfront + export credit	BB: 10-yr BB BYOD L1: 3-yr BYOD+: 5-yr
Delaware **Delmarva LDR + BYOD/BYOB/DLC** **(Docket 25-1554)** **proposed 2027-2029**	BYOD $25/device + $40/yr; BYOB $125/kW-yr + event kWh; DLC 2.0 $40/$60/$80/Year Smart Charge $5/$10 mo.	(basis not stated)	Yes: Proposed: LDR bonus $100/kW BYOD +$25/yr (DLC excluded)	Proximity-based (basis not stated)	Regulator Utility Filing	Not stated (2027-2029 portfolio)	Not stated DR events	Enrolled MW or Device + capacity ($/kW) + event kWh payment	Not stated
Maryland **DRIVE Act (HB 1256; PSC Cases 9761/9778)** **program not final**	Potomac Edison proposed up to $300/kW-yr	TBD by PSC “cover cost of DER to owner or aggregator”	Yes PSC directive (Case 9761) structure not final	TBD by PSC	Legislation Regulator	2-yr pilots (PSC directive) 2% peak enrollment cap	Not specified (>=30 events/yr per statute)	Pay for performance	2-yr pilots; 5-yr min for upfront-incentive customers
Nevada **NV Energy GSR-E/GSR-C (Dockets 25-10012/13)** **proposed**	Distribution $25/kW-yr & Generation and Transmission $120/kW-yr, x 30% Capacity Resource Rate	Marginal cost	Yes: Proposed: location-specific Distribution Node rate; default system-wide	Marginal cost	Utility Filing	Annual requalification	Event-based no fixed window	Performance vs customer-specific baseline	Annual default; optional multi-year (<=10 yr)

Thank You

Eric Cutter, Partner

Jeremy Laundergan: Senior Director

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