NASEO
National Association of
State Energy Officials

National Association of Regulatory Utility Commissioners
Dedicated to Public Service
1889

NARUC-NASEO DER I&C WEBINAR: LIGHTING ROUNDS AND DISCUSSION OF RECENT DSP AND DER INTEGRATION PUBLICATIONS

February 14, 2025

AGENDA

1. **Overview & What to Expect (5 mins)**
2. **Lightning Round Presentations (40 mins, 3 mins per report)**
    - **Lisa Schwartz, Lawrence Berkeley National Laboratory (LBNL)**
    - **Sean Murphy, LBNL**
    - **Natalie Mims Frick, LBNL**
    - **Guillermo Pereira, LBNL**
    - **Paul De Martini, Newport Consulting Group**
    - **Natalie Mims Frick, LBNL**
    - **Sydney Forrester, LBNL**
    - **Jen Downing, DOE Loan Programs Office**
3. **Breakout Rooms with Authors (40 mins, move rooms as desired)**
4. **Closing (5 mins)**

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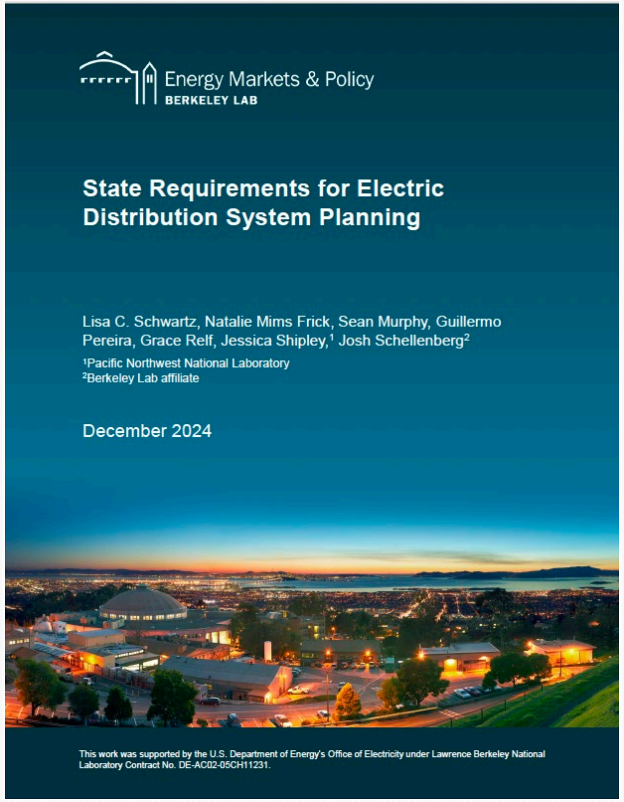
State requirements for electric distribution system planning

Report summarizes guidance from legislatures and regulators and identifies leading planning practices in 20 jurisdictions

- Goals and objectives
- Procedural elements
- Stakeholder engagement
- Forecasting loads and DERs
- Hosting capacity analysis
- Information on the current state of the distribution system
- Grid modernization strategy
- Grid needs assessment
- Non-wires alternatives (NWA)
- Reliability and resilience
- Pilots
- Coordination with other planning processes



Energy Markets & Policy
BERKELEY LAB

State Requirements for Electric Distribution System Planning

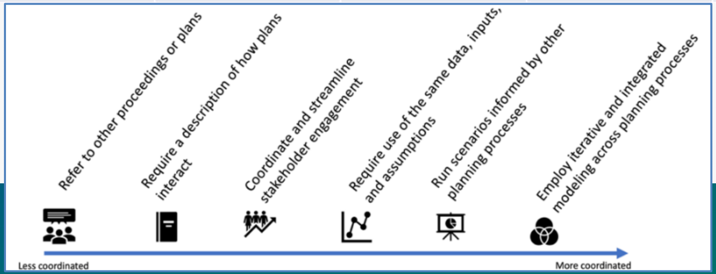
Lisa C. Schwartz, Natalie Mims Frick, Sean Murphy, Guillermo Pereira, Grace Relf, Jessica Shipley,[1] Josh Schellenberg[2]
[1]Pacific Northwest National Laboratory
[2]Berkeley Lab affiliate

December 2024

This work was supported by the U.S. Department of Energy's Office of Electricity under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

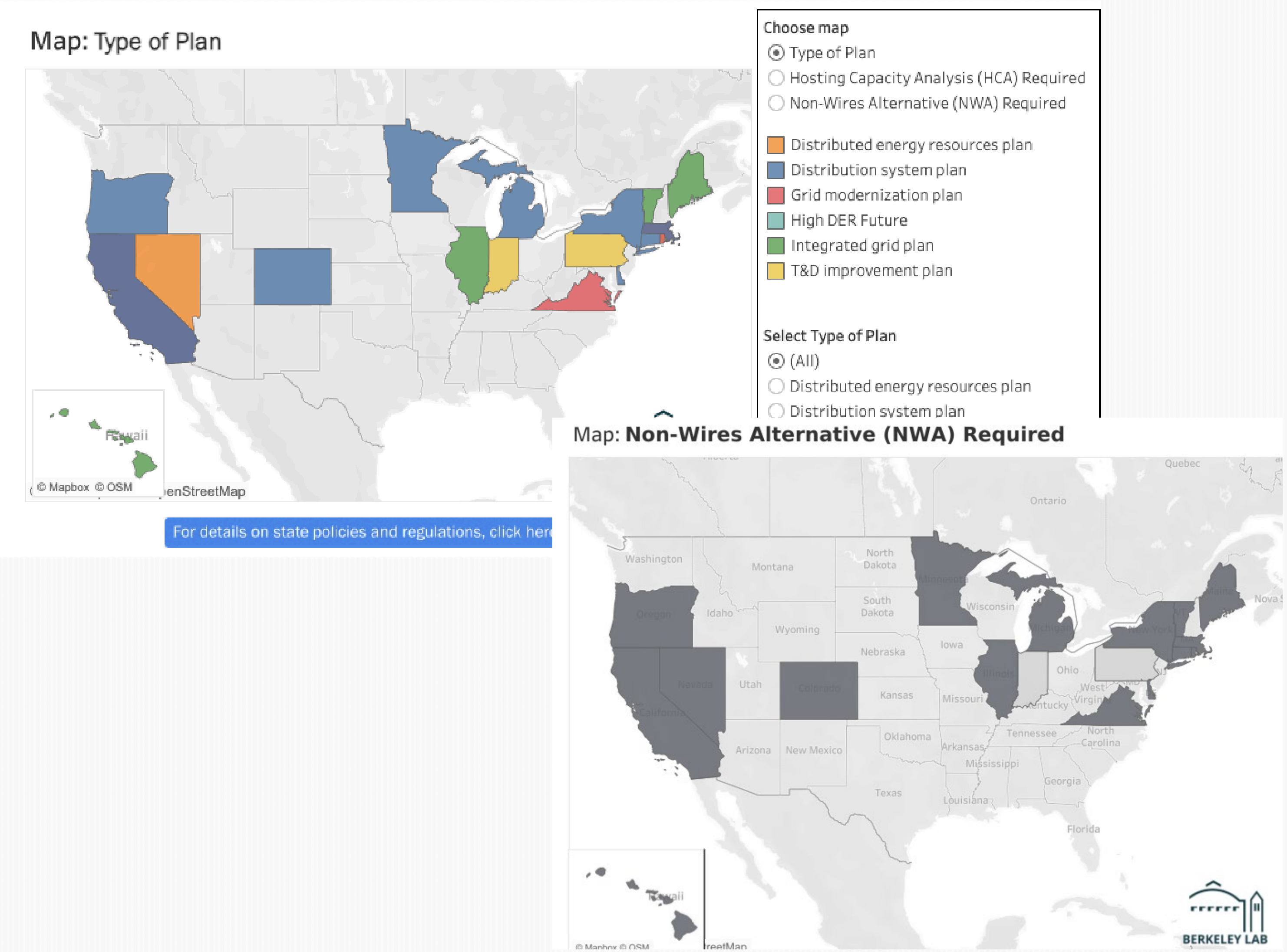
Coordination of Distribution Planning With Other Plans

State	Bulk Power (IRP and Transmission)	DERs (including efficiency)	Electrification	Other Related Plans	Highest Level of Coordination
CA	●	●	●	●	📈
CO	●	●	●	●	📈
DC				●	👥
HI	●	●	●	●	⊛
IL	●	●	●	●	📘
ME	●	●	●	●	📊
MA	●	●	●	●	🚶
MI	●	●			📈
MN	●		●	●	📊
NV	●	●			📈
NM	●			●	📈
NH		●		●	📘
NY	●	●	●	●	⊛
OR	●	●	●	●	📊
RI		●		●	📘
VT	●	●	●	●	⊛
VA	●			●	📘
WA	●	●	●	●	⊛



DSP data visualization and online catalog

- **Interactive interface**
  - Types of distribution plans
  - Filing frequency and planning horizon
  - NWA and hosting capacity analyses
- **Details by state**
  - Proceedings and orders
  - Filed utility plans
  - Type of regulatory action
  - State goals and objectives
  - Term of action plan
  - Stakeholder engagement
- **PUCs review and validate information**
- **Library of state documents**
- **Customizable maps for export**
- ***Update completed next month***



Map: Type of Plan

Choose map
● Type of Plan
○ Hosting Capacity Analysis (HCA) Required
○ Non-Wires Alternative (NWA) Required

🟧 Distributed energy resources plan
🟦 Distribution system plan
🟥 Grid modernization plan
■ High DER Future
🟩 Integrated grid plan
🟨 T&D improvement plan

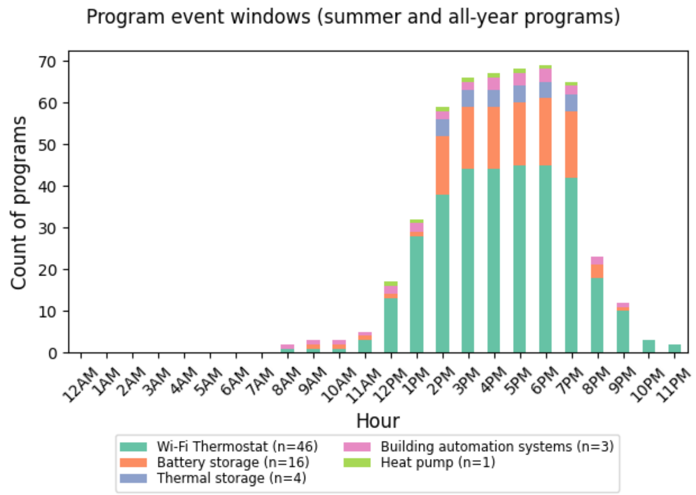
Select Type of Plan
● (All)
○ Distributed energy resources plan
○ Distribution system plan

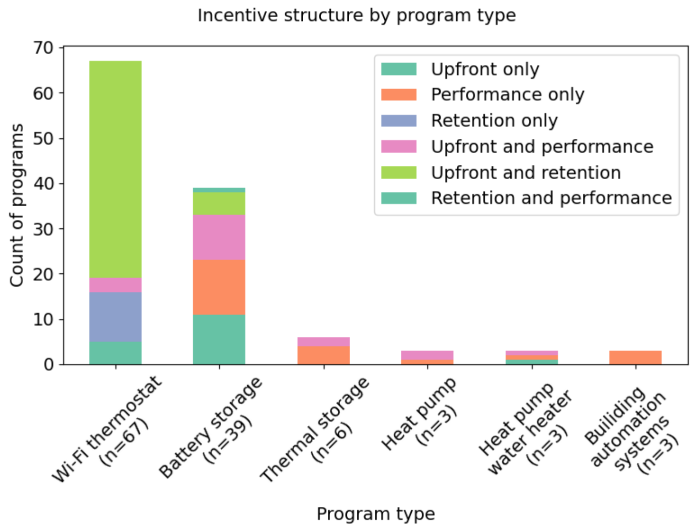
For details on state policies and regulations, click here

Map: **Non-Wires Alternative (NWA) Required**

The State of Demand Flexibility Programs and Rates

- The report characterizes electricity rates and utility programs that promote demand flexibility
  - Studied programs largely involve Wi-Fi thermostat and batteries
  - Studied rates have a dynamic component or technology requirement
- Results cover:
  - When and how frequently program and dynamic rate events may occur
  - The structure of program incentives and how they relate to demand flexibility technologies
  - The range of incentive amounts offered in Wi-Fi thermostat and battery programs
  - Program enrollment levels, event demand reductions, and cost of saved peak demand
  - Event prices for critical peak price rates
- The report informs discussions on demand flexibility program and rate design, program reporting requirements, and demand flexibility potential


Program event windows (summer and all-year programs)


Incentive structure by program type

Bridging the Gap on Data and Analysis for Distribution System Planning

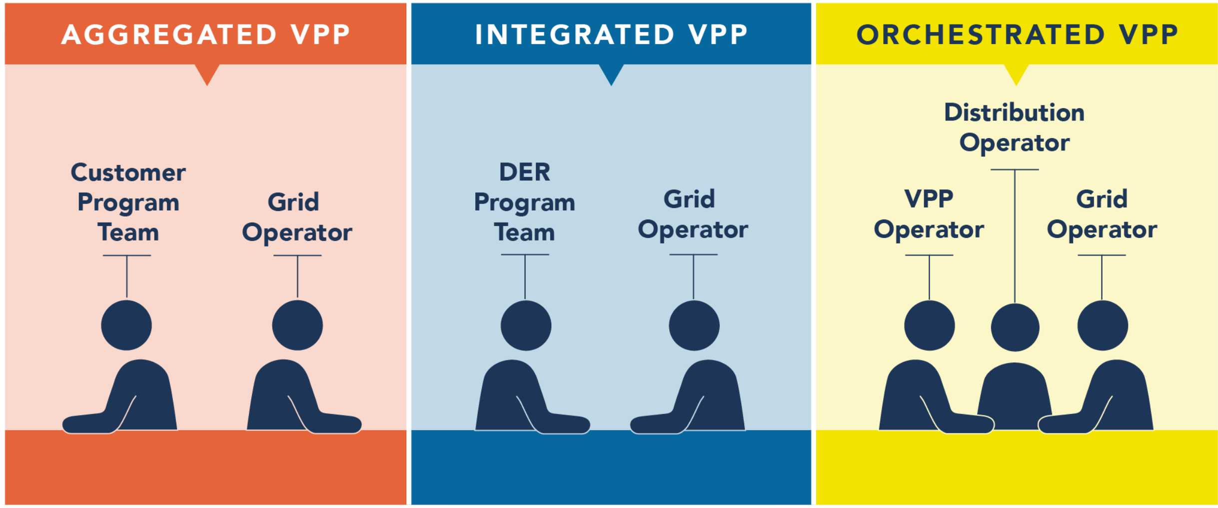
- This report aims to increase the understanding of the data, metrics, and analysis that regulators and stakeholders can ask for in distribution system planning proceedings
- For 11 distribution system planning topics, we:
  - Identify the data that utilities can report
  - Describe how those data impact planning
  - Present examples of and best practices on utility data sharing
- We share insights from interviews with regulators, state energy offices, and utilities on:
  - Information-sharing approaches and issues
  - Using information shared by utilities
  - Planning and decision-making impacts of data sharing
- A data tool organizes the data, metrics, and analysis on each planning topic
  - Regulators, state energy offices, and other stakeholders can adapt the tool to their needs

Distribution system planning topics covered
Forecasting loads and distributed energy resources
Scenario analysis
Worst-performing circuits
Asset management strategy
Hosting capacity analysis
Value of DERs
Grid needs assessment
Cost-effectiveness evaluation for investments
Distribution system investment strategy and implementation
Geotargeted programs
Non-wires alternatives procurements

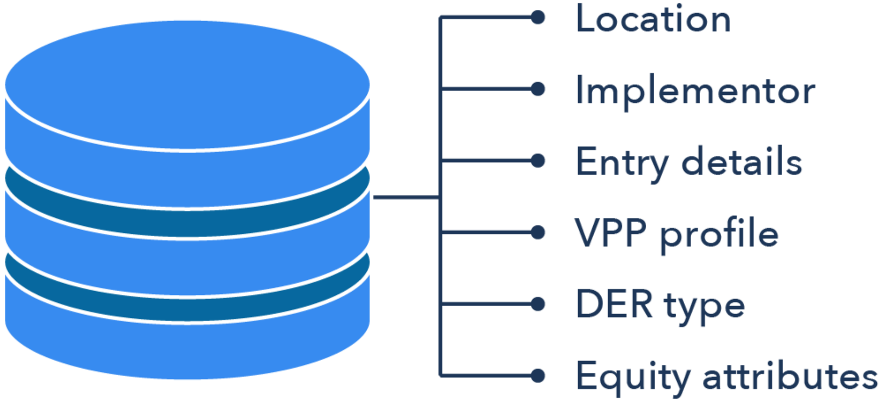
Virtual power plants: Insights, profiles and inventory

Insights and Profiles

- Role of leadership in successful VPP designs
- Grid and technology investments
- Program planning and design



Inventory



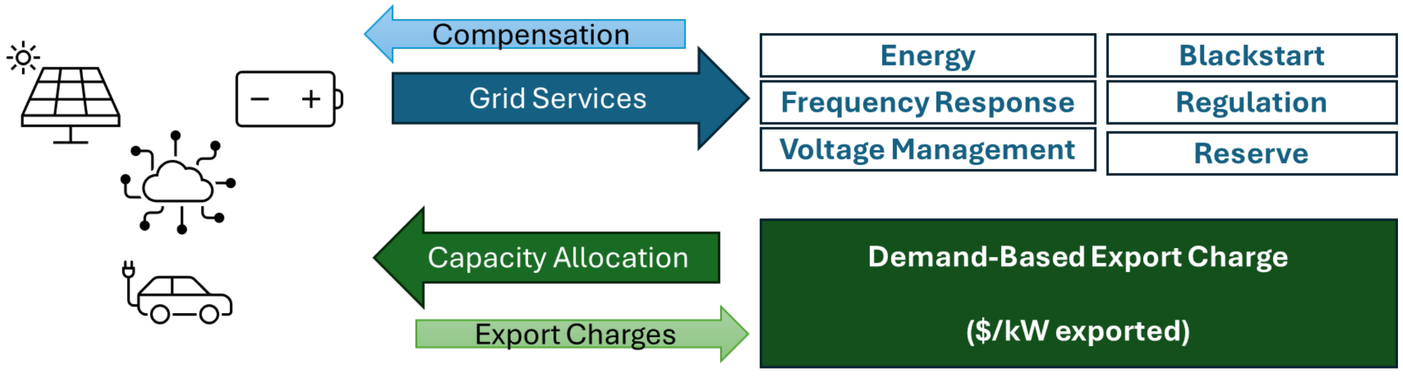
- Location
- Implementor
- Entry details
- VPP profile
- DER type
- Equity attributes

- The Research dataset includes 180 VPP programs with a potential VPP capacity of 19 GWs.
- The EIA DER dataset includes data on existing DR programs and NEM resources from the 2023 EIA-861 data. It has approximately 790 existing DR programs and NEM resources with a capacity of 27 GWs.

Reports and inventory available here

Distributed energy resource (DER) integration framework: Regulatory innovation for DER compensation and cost allocation

DER Integration Tariff Framework – Conceptual Structure



Compensation

Grid Services

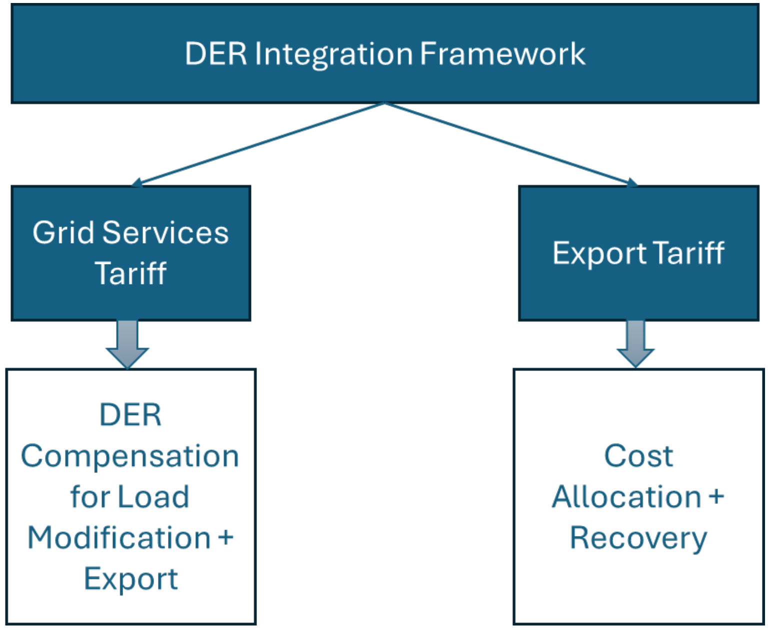
Energy
Frequency Response
Voltage Management
Blackstart
Regulation
Reserve

Capacity Allocation

Export Charges

Demand-Based Export Charge

($/kW exported)



DER Integration Framework

Grid Services Tariff

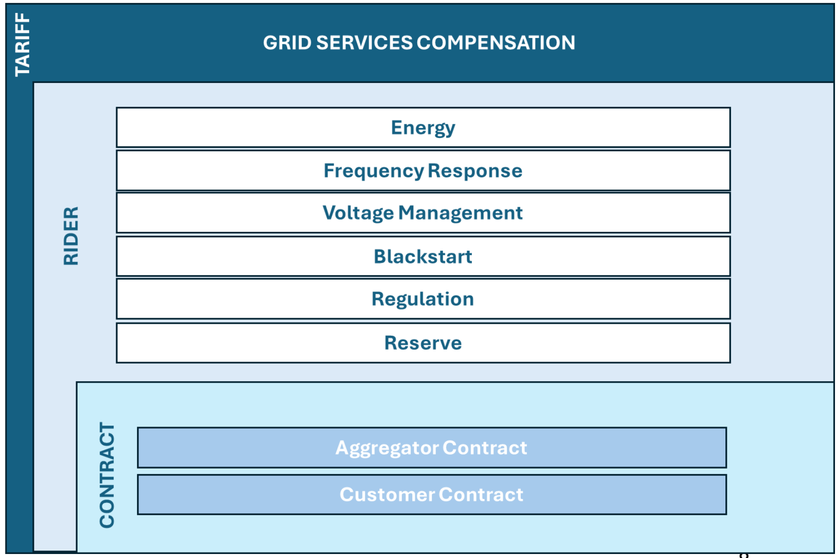
Export Tariff

DER Compensation for Load Modification + Export

Cost Allocation + Recovery

DER Integration Framework Conceptual Approach

- Framework to support DER compensation and cost allocation approach
- DERs are compensated through Grid Services Tariff by providing specified grid services, based on performance requirements rather than technology type
- Export Tariff addresses cost allocation and recovery challenges by applying ratemaking principles traditionally used for load customers to exporting DERs
- Report is available here



TARIFF

GRID SERVICES COMPENSATION

RIDER

Energy
Frequency Response
Voltage Management
Blackstart
Regulation
Reserve

CONTRACT

Aggregator Contract
Customer Contract

Unlocking load growth at the grid edge: Practices for managing, recovering, and allocating distribution system investments

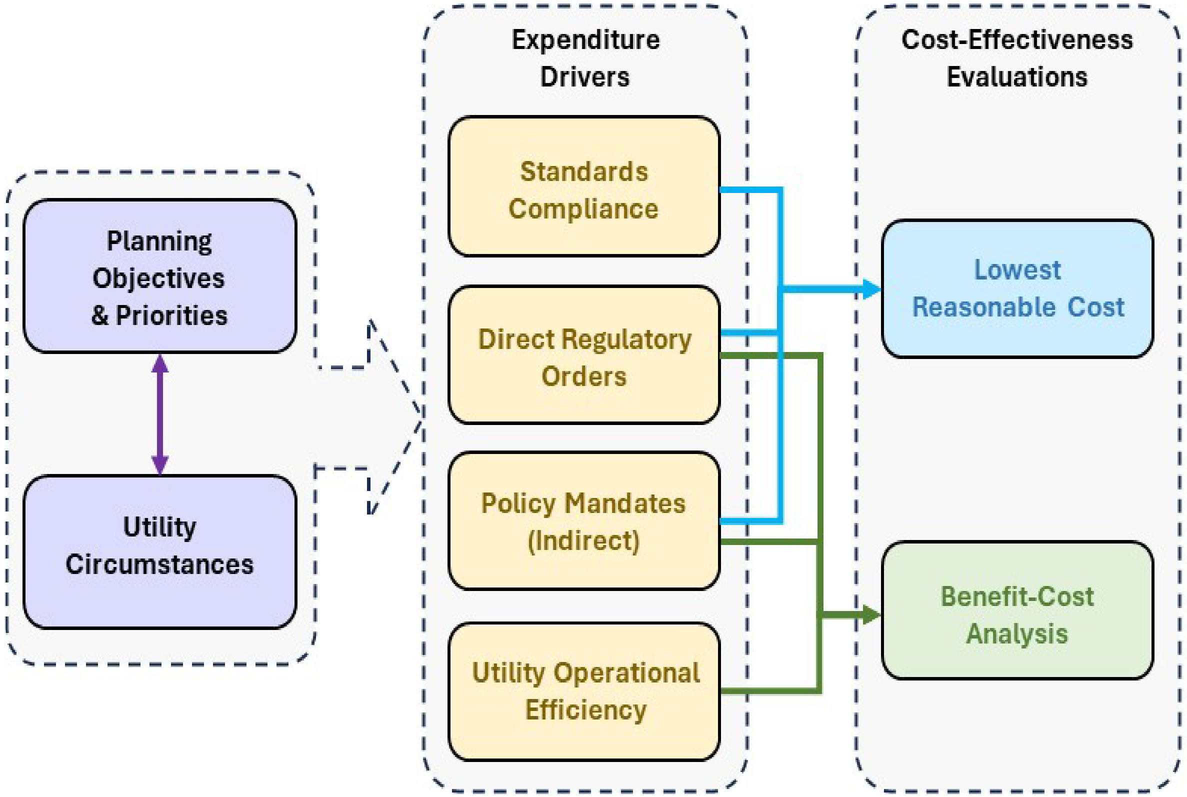
- Resource focused on load growth at the grid edge, driven by electric vehicle and heat pump adoption
- Informed by a detailed review of legislative actions and regulatory proceedings in
  - Arkansas, California, Colorado, Illinois, Massachusetts, Maryland, Michigan, Minnesota, New York, North Carolina, Oregon, Pennsylvania, Rhode Island, and Washington
- Provides information on utility and regulatory practices to recover and allocate distribution system investments deployed through utility programs, line extension policies, and proactive investments

Report download:
https://emp.lbl.gov/publications/unlocking-load-growth-grid-edge

Utility programs	Program design elements, capitalization vs. expensing of behind-the-meter assets, budget flexibility, rates, and load management	Cost recovery and allocation practices with details on utility proposals and commission orders
Line extension policies	Review and characterization of utility line extension policy reforms to address infrastructure needs at the grid edge	Identification of policy design elements, including allowance support provided, asset scope, infrastructure utilization, and future-proofing
Proactive investment approaches	Risk considerations for *just-in-time* and *proactive* investment approaches	Risk mitigation strategies across procedural, financial, and public policy domains

Economic Evaluation of Modernization Expenditures for Electric Utility Distribution Systems

Updated guidance for evaluating distribution modernization expenditures with practical examples



Planning Objectives & Priorities

Utility Circumstances

Expenditure Drivers

Standards Compliance

Direct Regulatory Orders

Policy Mandates (Indirect)

Utility Operational Efficiency

Cost-Effectiveness Evaluations

Lowest Reasonable Cost

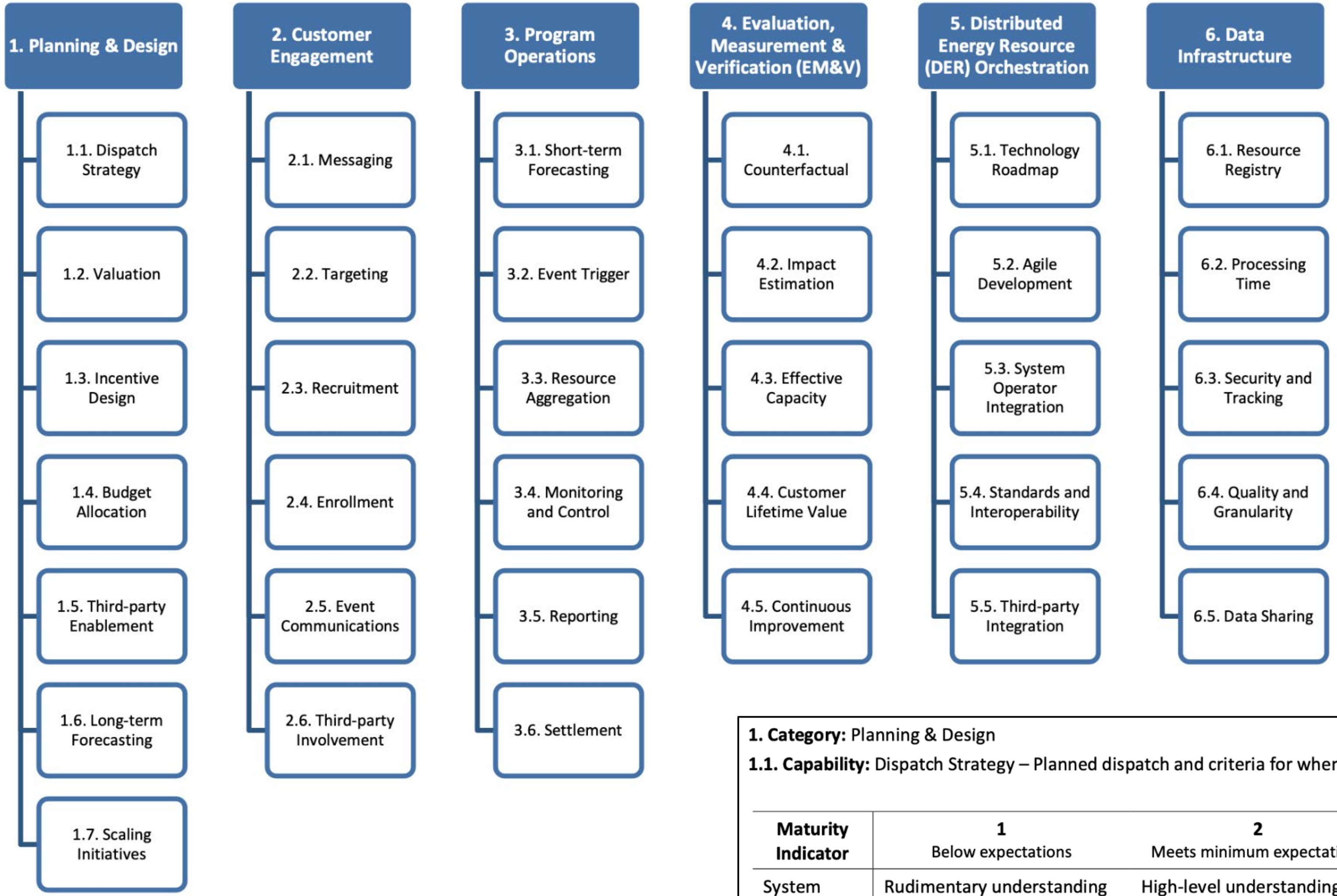
Benefit-Cost Analysis

Lowest Reasonable Cost – is a quantitatively focused method based on engineering or technology architectural analysis, or both to discern the necessity and cost of a solution based on compliance with statutory requirements and explicit or implicit regulatory requirements identified in the distribution planning process.

Benefit-Cost Analysis is a quantitatively focused method based on monetizing the benefits and costs of distribution modernization expenditures over a defined time period. It is best used when the dollar value of the benefits of a distribution modernization solution is discrete, assignable, and quantitatively measurable.

https://emp.lbl.gov/publications/economic-evaluation-distribution

Moving beyond direct load control: A maturity model for realizing the promise of demand flexibility



1. Planning & Design
- 1.1. Dispatch Strategy
- 1.2. Valuation
- 1.3. Incentive Design
- 1.4. Budget Allocation
- 1.5. Third-party Enablement
- 1.6. Long-term Forecasting
- 1.7. Scaling Initiatives

2. Customer Engagement
- 2.1. Messaging
- 2.2. Targeting
- 2.3. Recruitment
- 2.4. Enrollment
- 2.5. Event Communications
- 2.6. Third-party Involvement

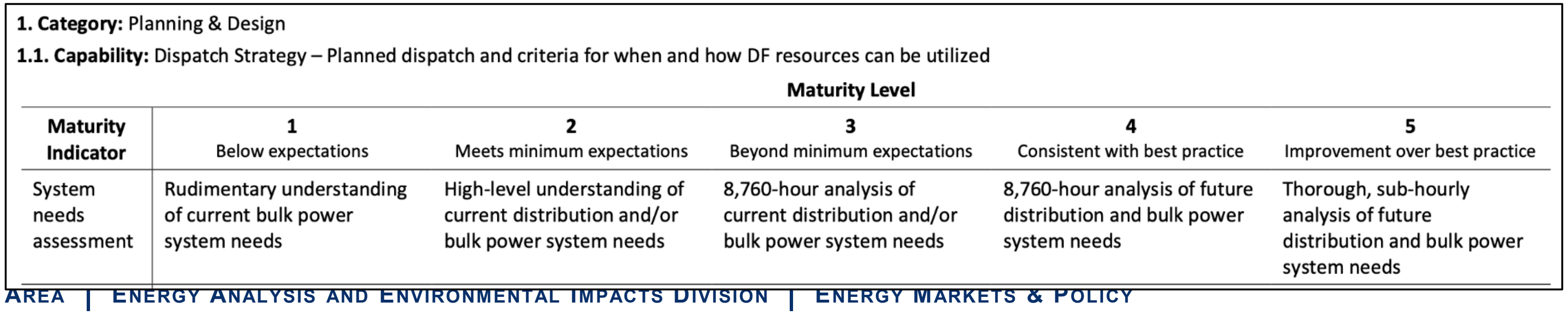
3. Program Operations
- 3.1. Short-term Forecasting
- 3.2. Event Trigger
- 3.3. Resource Aggregation
- 3.4. Monitoring and Control
- 3.5. Reporting
- 3.6. Settlement

4. Evaluation, Measurement & Verification (EM&V)
- 4.1. Counterfactual
- 4.2. Impact Estimation
- 4.3. Effective Capacity
- 4.4. Customer Lifetime Value
- 4.5. Continuous Improvement

5. Distributed Energy Resource (DER) Orchestration
- 5.1. Technology Roadmap
- 5.2. Agile Development
- 5.3. System Operator Integration
- 5.4. Standards and Interoperability
- 5.5. Third-party Integration

6. Data Infrastructure
- 6.1. Resource Registry
- 6.2. Processing Time
- 6.3. Security and Tracking
- 6.4. Quality and Granularity
- 6.5. Data Sharing

- States and utilities can adapt and use the maturity model to prioritize investment, identify gaps, and drive continuous improvement to realize their DF goals
- Maturity model can be used to assess utility programs based on 34 demand flexibility (DF) capabilities, organized into the six categories
- Each of the six maturity model categories has 5 to 7 capabilities and can be scored 1-5
- Builds on existing maturity models (e.g., wildfire mitigation)



1. Category: Planning & Design

1.1. Capability: Dispatch Strategy – Planned dispatch and criteria for when and how DF resources can be utilized

	Maturity Level				
Maturity Indicator	**1** Below expectations	**2** Meets minimum expectations	**3** Beyond minimum expectations	**4** Consistent with best practice	**5** Improvement over best practice
System needs assessment	Rudimentary understanding of current bulk power system needs	High-level understanding of current distribution and/or bulk power system needs	8,760-hour analysis of current distribution and/or bulk power system needs	8,760-hour analysis of future distribution and bulk power system needs	Thorough, sub-hourly analysis of future distribution and bulk power system needs

Report available **here**

State regulatory opportunities to advance DER aggregations in wholesale markets

State regulator role and influence

Coordination

- Regionally (across states, RTO/ISOs)
- Across utilities, aggregators, etc.

Policy and regulation

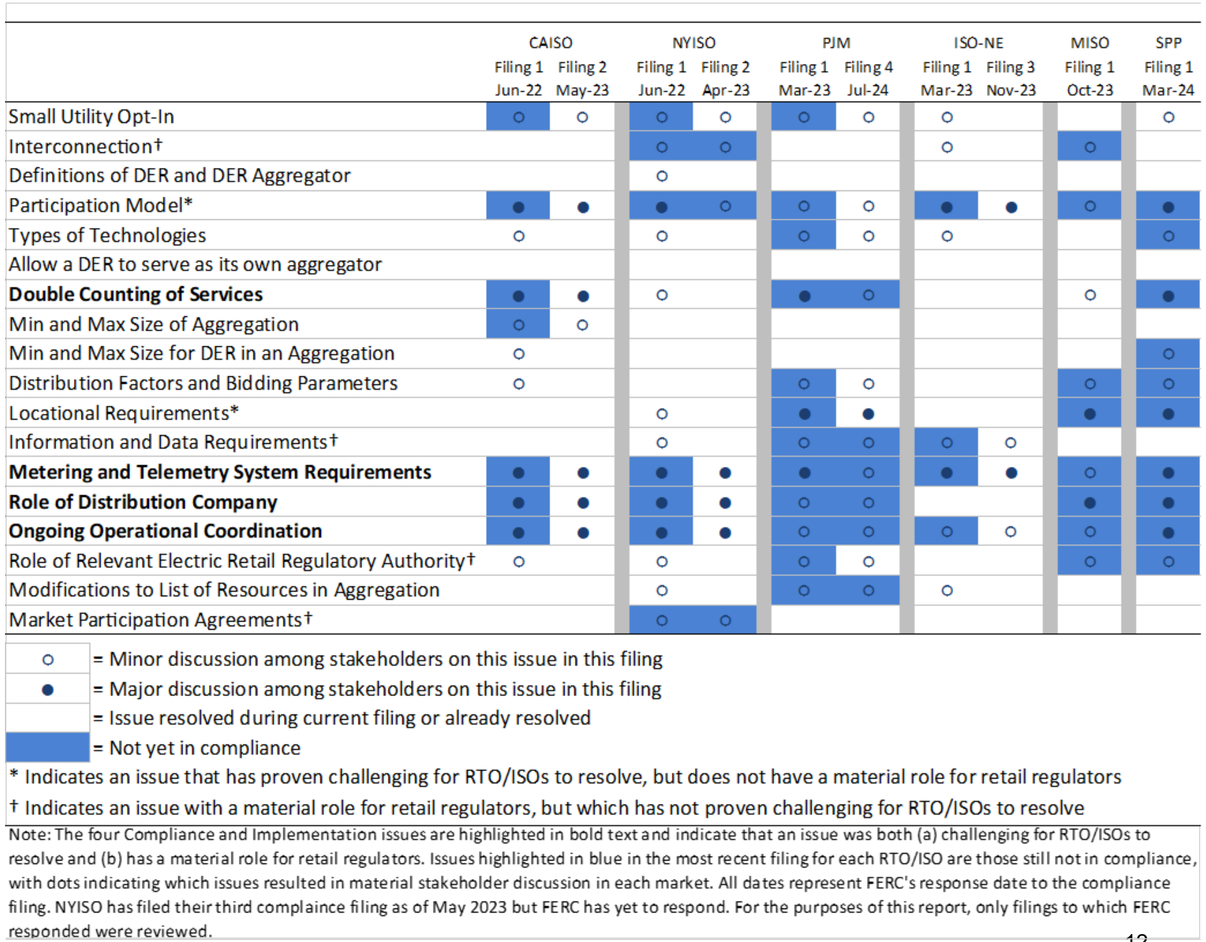
- Rate design, incentive and program design
- Resource planning
- Performance and deployment targets, goals

Data collection, evaluation sharing

- Interconnection agreements: metering, telemetry
- Data sharing and privacy
- Evaluation metrics and methods

Report available [here]()

Wholesale market progress on Order 2222: Compliance and implementation issues



	CAISO		NYISO		PJM		ISO-NE		MISO	SPP
	Filing 1 Jun-22	Filing 2 May-23	Filing 1 Jun-22	Filing 2 Apr-23	Filing 1 Mar-23	Filing 4 Jul-24	Filing 1 Mar-23	Filing 3 Nov-23	Filing 1 Oct-23	Filing 1 Mar-24
Small Utility Opt-In	🟦 ○	○	🟦 ○	○	🟦 ○	○	○			○
Interconnection†			🟦 ○	🟦 ○			○		🟦 ○	
Definitions of DER and DER Aggregator			○							
Participation Model*	🟦 ●	●	🟦 ●	🟦 ○	🟦 ○	○	🟦 ●	●	🟦 ○	🟦 ●
Types of Technologies	○		○		🟦 ○	○	○			🟦 ○
Allow a DER to serve as its own aggregator										
Double Counting of Services	🟦 ●	●	○		🟦 ●	🟦 ○			○	🟦 ●
Min and Max Size of Aggregation	🟦 ○	○								
Min and Max Size for DER in an Aggregation	○									🟦 ○
Distribution Factors and Bidding Parameters	○				🟦 ○	○			🟦 ○	🟦 ○
Locational Requirements*			○		🟦 ●	●			🟦 ●	🟦 ●
Information and Data Requirements†			○		🟦 ○	🟦 ○	🟦 ○	○		
Metering and Telemetry System Requirements	🟦 ●	●	🟦 ●	●	🟦 ●	🟦 ○	🟦 ●	●	🟦 ○	🟦 ●
Role of Distribution Company	🟦 ●	●	🟦 ●	●	🟦 ○	🟦 ○			🟦 ●	🟦 ●
Ongoing Operational Coordination	🟦 ●	●	🟦 ●	●	🟦 ○	🟦 ○	🟦 ○	○	🟦 ○	🟦 ●
Role of Relevant Electric Retail Regulatory Authority†	○		○		🟦 ○	○			🟦 ○	🟦 ○
Modifications to List of Resources in Aggregation			○		🟦 ○	🟦 ○	○			
Market Participation Agreements†			🟦 ○	🟦 ○						

○ = Minor discussion among stakeholders on this issue in this filing

● = Major discussion among stakeholders on this issue in this filing

= Issue resolved during current filing or already resolved

🟦 = Not yet in compliance

* Indicates an issue that has proven challenging for RTO/ISOs to resolve, but does not have a material role for retail regulators

† Indicates an issue with a material role for retail regulators, but which has not proven challenging for RTO/ISOs to resolve

Note: The four Compliance and Implementation issues are highlighted in bold text and indicate that an issue was both (a) challenging for RTO/ISOs to resolve and (b) has a material role for retail regulators. Issues highlighted in blue in the most recent filing for each RTO/ISO are those still not in compliance, with dots indicating which issues resulted in material stakeholder discussion in each market. All dates represent FERC's response date to the compliance filing. NYISO has filed their third complaince filing as of May 2023 but FERC has yet to respond. For the purposes of this report, only filings to which FERC responded were reviewed.

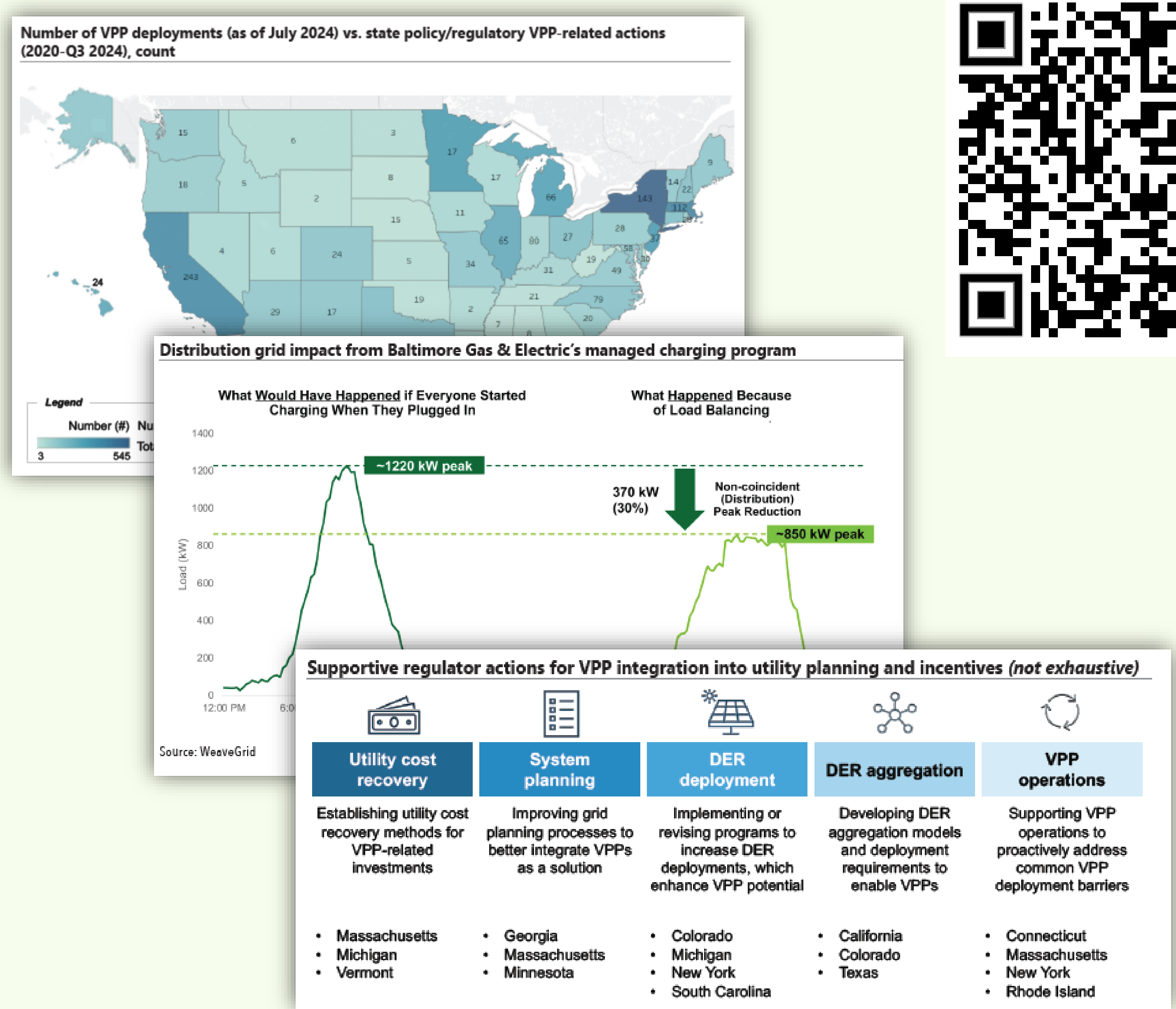
liftoff.energy.gov/vpp

U.S. DEPARTMENT OF ENERGY

Pathways to
Commercial Liftoff:
Virtual Power Plants
2025 Update

JANUARY | 2025

- 75+ real-world case studies
- 60+ new DOE and industry resources



Number of VPP deployments (as of July 2024) vs. state policy/regulatory VPP-related actions (2020-Q3 2024), count

Distribution grid impact from Baltimore Gas & Electric's managed charging program

Source: WeaveGrid

Supportive regulator actions for VPP integration into utility planning and incentives *(not exhaustive)*

Utility cost recovery	System planning	DER deployment	DER aggregation	VPP operations
Establishing utility cost recovery methods for VPP-related investments	Improving grid planning processes to better integrate VPPs as a solution	Implementing or revising programs to increase DER deployments, which enhance VPP potential	Developing DER aggregation models and deployment requirements to enable VPPs	Supporting VPP operations to proactively address common VPP deployment barriers
• Massachusetts • Michigan • Vermont	• Georgia • Massachusetts • Minnesota	• Colorado • Michigan • New York • South Carolina	• California • Colorado • Texas	• Connecticut • Massachusetts • New York • Rhode Island

BREAKOUT ROOMS

1. **Lisa Schwartz & Sean Murphy**
    - State Requirements for Electric Distribution System Planning
    - The State of Demand Flexibility Programs and Rates
    - Bridging the Gap on Data and Analysis for Distribution System Planning: Information That Utilities Can Provide Regulators, State Energy Offices and Other Stakeholders
2. **Natalie Mims Frick & Sydney Forrester**
    - Virtual Power Plants: Insights, Profiles and Inventory
    - Distributed Energy Resource (DER) Integration Framework: Regulatory Innovation for DER Compensation and Cost Allocation
    - Moving Beyond Direct Load Control: A Maturity Model for Realizing the Promise of Demand Flexibility
    - State Regulatory Opportunities to Advance Distributed Energy Resources Aggregations in Wholesale Markets
3. **Guillermo Pereira**
    - Unlocking load growth at the grid edge: Practices for Managing, Recovering, and Allocating Distribution System Investments
4. **Paul De Martini**
    - Economic Evaluation of Modernization Expenditures for Electric Utility Distribution Systems: A Guide for Utility Regulators
5. **Jen Downing**
    - Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update

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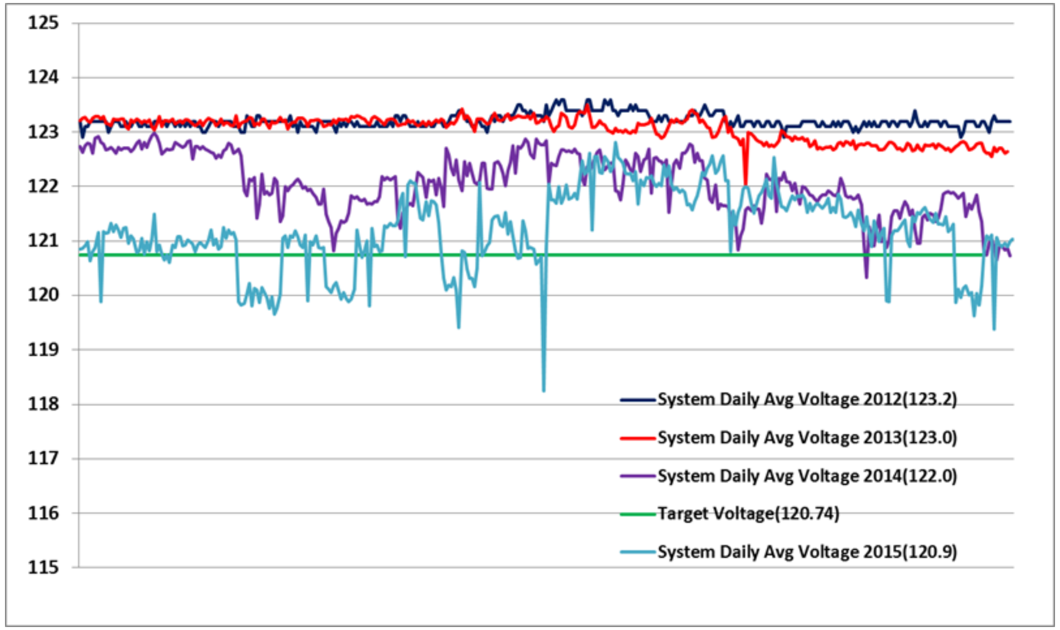
Slides for Appendix

Updated Cost-Effectiveness Framework & Case Examples

Expenditure drivers: Standards Compliance

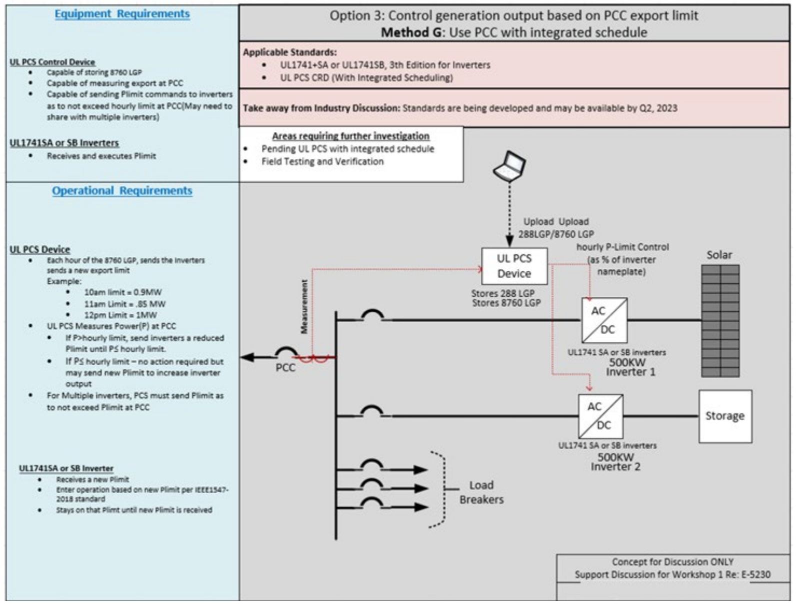
- **Standards Compliance** – Solutions to comply with safety, power quality, and reliability standards are addressed using Lowest Reasonable Cost (LRC).
  - *Example:* Voltage management solution to comply with the national electric service quality standard for voltage (ANSI C84) involving grid devices, including smart inverter settings, and integrated volt-var control (IVVC) software to manage inverters (*IVVC illustration on right*).
  - Example: Replacement of deteriorated wood poles not in compliance with ANSI 05.1 and relevant state regulations (e.g., CPUC General Order 95) to address safety and reliability



Source: Duke Energy

Expenditure drivers: Direct Regulatory Order

- **Direct Regulatory Order** – Solutions in response to a PUC order may be addressed using LRC or require a Benefit-Cost Analysis (BCA), depending, for example, on whether the decision and order included a finding that the required capability was in the interest of the public and utility customers. If so, then the LRC method may apply.
  - *Example:* California PUC ordered utilities to implement a specific approach to flexible DER interconnections involving a dynamic curtailment control scheme that will require utility expenditures to implement. The order determined that this new requirement was in the public interest, and the utility must implement the required approach using the lowest reasonable cost solution that conforms to the order. (*illustration on right*)



Equipment Requirements

UL PCS Control Device
- Capable of storing 8760 LGP
- Capable of measuring export at PCC
- Capable of sending Plimit commands to inverters as to not exceed hourly limit at PCC(May need to share with multiple inverters)

UL1741SA or SB Inverters
- Receives and executes Plimit

Operational Requirements

UL PCS Device
- Each hour of the 8760 LGP, sends the Inverters sends a new export limit
  Example:
  - 10am limit = 0.9MW
  - 11am Limit = .85 MW
  - 12pm Limit = 1MW
- UL PCS Measures Power(P) at PCC
  - If P>hourly limit, send inverters a reduced Plimit until P≤ hourly limit.
  - If P≤ hourly limit – no action required but may send new Plimit to increase inverter output
- For Multiple inverters, PCS must send Plimit as to not exceed Plimit at PCC

UL1741SA or SB Inverter
- Receives a new Plimit
- Enter operation based on new Plimit per IEEE1547-2018 standard
- Stays on that Plimt until new Plimit is received

Option 3: Control generation output based on PCC export limit
Method G: Use PCC with integrated schedule

Applicable Standards:
- UL1741+SA or UL1741SB, 3th Edition for Inverters
- UL PCS CRD (With Integrated Scheduling)

Take away from Industry Discussion: Standards are being developed and may be available by Q2, 2023

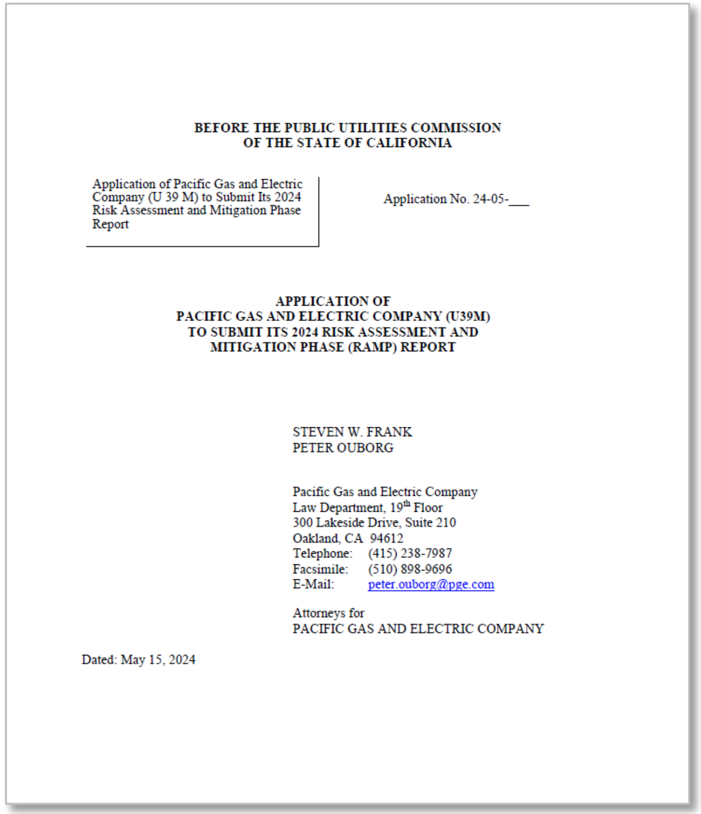
Areas requiring further investigation
- Pending UL PCS with integrated schedule
- Field Testing and Verification

Concept for Discussion ONLY
Support Discussion for Workshop 1 Re: E-5230

CPUC Selected Customer-Controlled Method (Source: CPUC)

Expenditure drivers: Policy Mandates

- **Policy Mandates** – For instance, legislation addressing wildfire risk considers societal value and compliance with the statute, which may require new enabling grid capabilities. However, not all policy mandates identify the value from the perspective of utility customers. In these cases, a BCA is used to determine the cost-effectiveness of solutions.
    - *Example:* Wildfire mitigation solutions are evaluated with BCA even in the face of a policy mandate as there is typically a need to prioritize expenditures that have the greatest mitigating impact. For example, this may be done by assessing the risk-spend efficiency of a wildfire mitigation solution. This approach is a derivation of a typical BCA.



BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report

Application No. 24-05-___

APPLICATION OF
PACIFIC GAS AND ELECTRIC COMPANY (U39M)
TO SUBMIT ITS 2024 RISK ASSESSMENT AND
MITIGATION PHASE (RAMP) REPORT

STEVEN W. FRANK
PETER OUBORG

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E-Mail: peter.ouborg@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: May 15, 2024

Source: PG&E 2024 RAMP Filing

Expenditure drivers: Utility Operational Efficiency

- **Utility Operational Efficiency**– Solutions identified by the utility to improve operations (not driven by compliance, regulatory, or policy mandates) are evaluated using BCA.
  - *Examples:* Solutions that create operational savings (e.g., operational control center consolidation) and adoption of technology innovations that increase productivity (e.g., field crew technology – see illustration)

Benefit-cost analysis

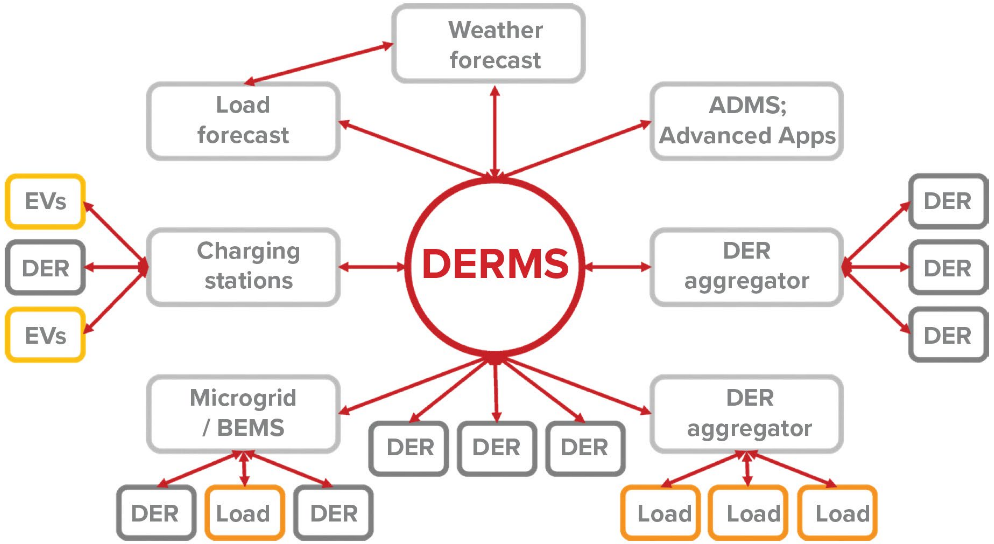
- BCA is a quantitatively focused method for assessing the net value to utility customers of a specific distribution modernization expenditure over a defined time period. The net value is determined by identifying utility, customer, and societal benefits compared to the expenditure's cost. A grid modernization BCA evaluates both:

  - ***Direct utility savings*** - Financial benefits that accrue directly to the utility in terms of cost savings that are quantifiable in dollar terms, measurable, and auditable. These savings have a tangible impact on a utility's financial performance. They involve a clear cause-and-effect relationship between changes due to the proposed expenditure, as reflected in related metrics, and the resulting financial outcome.

  - ***Indirect (non-utility) savings*** - Financial benefits that clearly accrue to customers or society or may accrue to utility but cannot be quantified. Indirect benefits may be harder to quantify in dollar terms, measure, or audit financial results. Indirect savings often require estimation or projections of dollar value. Certain grid modernization expenditures involve indirect monetary benefits such as improved customer reliability and societal gains. While not financially auditable, such non-utility benefits are important to assess.

BCA example: Utility DERMS

- A utility is proposing a Distributed Energy Resource Management System (DERMS) to manage the portfolio of DER services provided by DER aggregators, the utility's own demand response programs, flexible DER interconnections, and managed EV fleet charging.
- Utility conducts a BCA to assess cost-effectiveness of the proposed DERMS in the context of the benefits provided by the DER services and flexible demand programs enabled by the DERM solution.
- Ideally the DERMS cost would be included in the DER program costs to avoid duplication and align all implementation costs with the flexible demand programs.



Utility "Grid" DERMS
Source: Quanta Technology

BCA example: Utility DERMS (cont.)

- The value of the DERMS includes direct and indirect benefits from optimizing DER integration, reducing utility energy purchases, deferring distribution grid upgrades, deferring, or avoiding the need for new generation capacity, and avoiding GHG emissions.

Benefits Summary

Conceptual Example

Benefit Category	Annual Benefit	One-Time Benefit
Avoided Energy Purchases	$15 million	
Avoided Generation Build Costs		$240 million
Deferred Infrastructure Investments		$30 million (over 5 years)
GHG Reduction (Indirect Benefit)	$7.5 million	
Totals:	$22.5 million	$270 million

Cost Summary

Cost Category	Annual Cost	One-Time Cost
DERMS Capital Investment		$50 million
DER Program Development & Incentives	$1 million	$15 million
DERMS Operational & Maintenance (O&M)	$5 million	
Totals	$6 million	$65 million

Net Present Value (NPV) 20yrs @ 9% : **$355 million** (approx.)
Benefit-to-cost ratio: 4:1 (approx.)

BCA example: Distribution Automation - Reclosers

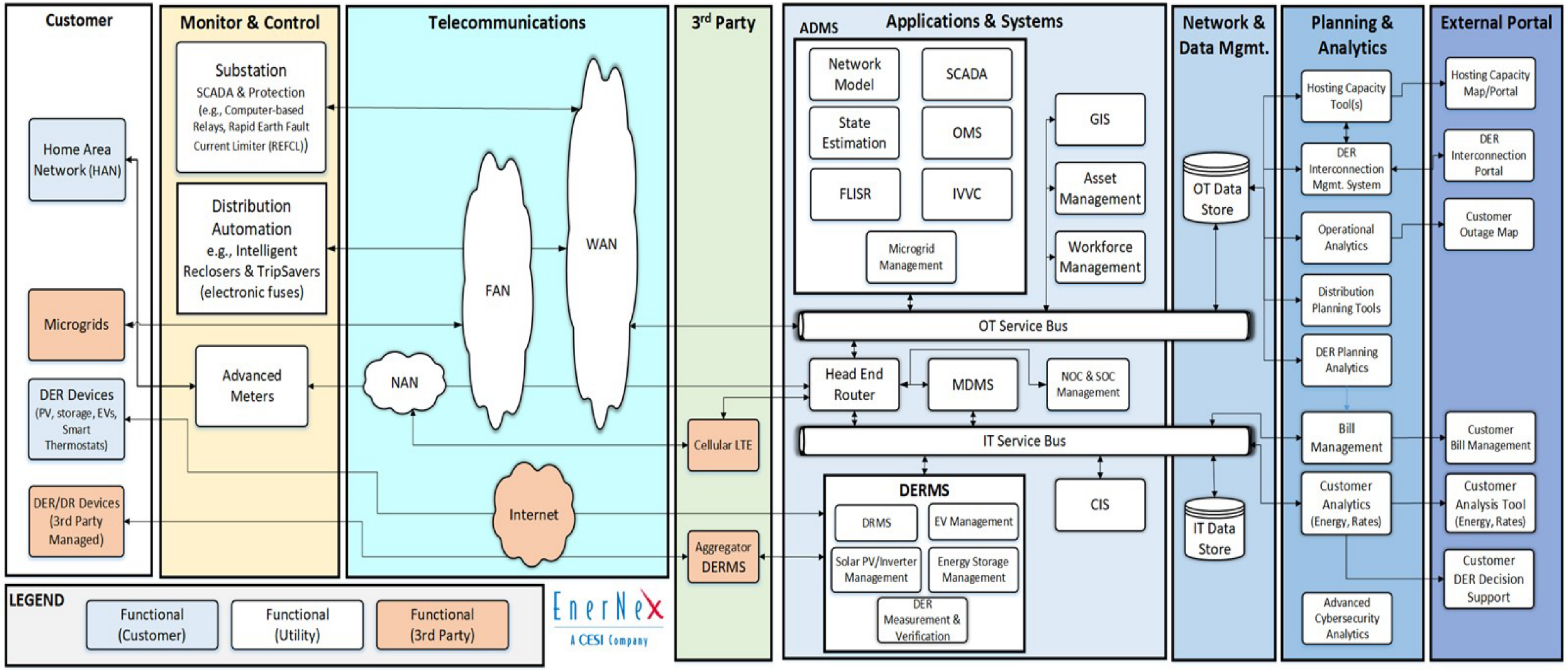
A utility proposes to deploy five sectionalizing reclosers on each feeder to improve reliability. Standard industry practice is to install at least one mid-point sectionalizing recloser on each feeder for reliability. If all feeders do not have such a recloser, then material improvements in reliability can often be achieved and quantified.

- Reliability benefits diminish as more reclosers are added to a circuit. While the cost of reclosers remains the same, the number of customers benefiting and the avoided outage duration decline, given the smaller segments.
- Berkeley Lab's ICE Calculator can be used to determine the optimal number of reclosers to install on an individual feeder to achieve the desired level of reliability cost-effectively.
- For reliability improvements, indirect dollar benefits are typically much greater than direct utility benefits, meaning that the proposed expenditure will be an incremental cost. That is why it is essential to establish the reference metric for the overall target level of service reliability based on specific reliability metrics (e.g., CAIDI – Customer Average Interruption Duration Index) or peer benchmark rankings (e.g., maintaining 2nd quartile ranking), or both.
- It is desirable to assess all individual reliability improvement measures holistically as a program against the overall reliability objective and metric(s) in a distribution system plan.

Automated Recloser Switch
Source: T&D World

LRC example: Advanced Distribution Management System

A utility requires a better understanding of real-time operational conditions, based on current and forecasted DERs and electric vehicle (EV) charging interconnected to its distribution system. The utility intends to replace its obsolete distribution Supervisory Control and Data Acquisition (SCADA) system. The existing outage management system will be replaced in 4 years. IVVC capability may be needed in 6 years, depending on actual DER and EV adoption rates.



LRC example: Advanced Distribution Management System (cont.)

- A BCA involving each current and future option would require determining marginal benefits from new capabilities, current and future software replacements, and potential additional modules based on assumptions of future software enhancements, timing of need, co-dependent field technologies (as in the case of the IVVC module), and any adjustment for the risk of mis-timing a future decision.
- This is impractical because the decision is not whether an ADMS platform with an initial Network Model and SCADA is justified – that decision is determined through the needs analysis in the distribution system plan.
- The task is to determine which vendor solution is the most cost-effective in terms of capital and ongoing operational and maintenance costs based on a comparative level of functionality — the least-cost, best-fit solution.

			Capital Costs (one time)				O&M Expense (annual)		
ADMS Platform w/Network Model, SCADA Modules	**Functionality (1-10)**	**Implement Risk**	**License Cost**	**Non-recurring Engineering Cost**	**Configuration Cost**	**Total Capital**	**Maintenance Costs**	**Cloud Computing Costs**	**Total Annual O&M**
Vendor A	9	Low	$5,000,000	$0	$175,000	$5,175,000	$750,000	$100,000	$850,000
Vendor B	8	Med	$4,750,000	$300,000	$150,000	$5,200,000	$757,500	$125,000	$882,500
Vendor C	6	High	$4,250,000	$1,000,000	$200,000	$5,450,000	$787,500	$100,000	$887,500

ENERGY MARKETS & POLICY

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