COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF ENERGY RESOURCES

Grid Modernization Advisory Council

August 10, 2023

Agenda

Item	Time
Welcome, Agenda, Roll call	12:00 – 12:05
Public Comment	12:05 – 12:35
Meeting minutes review and voting	12:35 – 12:40
Executive Committee meeting updates	12:40 – 12:45
GMAC ESMP Review Plan	12:45 – 1:20
Topic 1: DER Integration	1:20 – 2:20
10-minute Break	*2:20 – 2:30*
Topic 2: Cost Allocation	2:30 – 3:30
Public Comment	3:30 – 3:55
Close	3:55 – 4:00

Public Comment

- 30-minute period for public comment
- Time limit of 3 minutes per comment

Meeting Minutes

- Calling for vote to finalize:
  - July GMAC minutes
  - July GMAC Executive Committee minutes

- *Motion to approve the July minutes [as distributed/as corrected]?*

Executive Committee Meeting Updates

- Procurement of consultant underway, expect to kick-off with the consultant in mid-August
- Discussed a plan for reviewing the ESMP drafts (see coming slides)

Planning the ESMP Review Period (1 of 7)

- **Expectations of members:**
  - Be prepared to discuss sections based on review calendar.
  - Submit recommendations and information requests in a predefined template format for discussion.
  - Be familiar with legislative directive of the GMAC and other council priorities such as integrating equity considerations and ratepayer impacts through ESMP plan review.
- **Meeting cadence:** Biweekly (every other week) GMAC council meetings. See detailed proposal on next slide.
- **Final product:** Cover letter type resolution with high level comments + excel sheet with specific recommendations and member votes
- **Proposal for Public Engagement during review period**
  1. 10/31: 90-minute GMAC Listening Session
  2. EDC Technical Sessions (~Late October/Early November)
  3. Written Public Comment to MA-GMAC@mass.gov
  4. Stakeholder outreach to GMAC members

DOER
Massachusetts Department of Energy Resources

Planning the ESMP Review Period (2 of 7)

September

M	T	W	Th	F
				1 Receive ESMPs
4	5	6	7	8
11	12	13	14	15
18	19	20	21	22
25	26	27	28	29 X

October

M	T	W	Th	F
2	3	4	5	6
9	10	11	12	13
16	17	18	19	20
23	24	25	26	27 X

November

M	T	W	Th	F
30	31	1	2	3
6	7	8	9	10
13	14	15	16	17 X
20 Feedback to EDCs	21	22	23	24

Review Final Document (week of 6–10 November)

Finalize Comments (week of 13–17 November)

- Sept. 14th Scheduled GMAC Meeting
- Sept. 28th Proposed New GMAC Meeting
- Oct. 12th Scheduled GMAC Meeting
- Oct. 26th Proposed New GMAC Meeting
- Oct. 31st Proposed 90 Min Listening Session
- Nov. 9th Scheduled GMAC Meeting
- Nov. 16th Proposed New GMAC Meeting
- X ExCom Meeting

Preread material

- EEAC Final Resolution

GMAC Meeting Discussion Plan

- **9/14**: Stakeholder Engagement, Current State, Gas-Electric Planning, Workforce Economic & Health benefits (Sections 3, 4, 11, 12)
- **9/28**: 5–10-year forecast and solutions, Reliable & Resilient (Sections 5, 6, 10)
- **10/12**: 2035-2050 Drivers and Solutions (Sections 8, 9)
- **10/26**: Executive Summary, 5-year ESMP, Conclusion (Sections 1, 7, 13)
- **11/9**: Discuss draft recommendations
- **11/16**: Finalize recommendations

What do you think about the proposed meeting schedule? Consider also forthcoming meetings from EDCs on technical sessions and CETWG coordination meeting.

Sample Agendas During ESMP Review (3 of 7)

September 14th

1:00 – 1:15	Administrative Items
1:15 – 1:55	**Section 3:** Stakeholder Engagement
1:55 – 2:30	**Section 4:** Current State of DS
2:30 – 2:40	**BREAK**
2:40 – 3:20	**Section 11:** Gas-Electric Planning
3:20 – 3:57	**Section 12:** Workforce, Economic, & Health Benefits
3:57 – 4:00	Close

~40 minutes for each Section
- 10 mins consultant
- 30 mins discussion

September 28th

1:00 – 1:15	Administrative Items
1:15 – 1:55	Continued Day 1 Discussion
1:55 – 2:30	**Section 5:** 5- and 10-Year Demand Forecast
2:30 – 2:40	**BREAK**
2:40 – 3:20	**Section 6:** 5- and 10-Year Solutions
3:20 – 3:57	**Section 10:** Reliable & Resilient DS
3:57 – 4:00	Close

~40 minutes for each Section
- 10 mins consultant
- 30 mins discussion

October 12th

1:00 – 1:15	Administrative Items
1:15 – 1:55	Continued Day 2 Discussion
1:55 – 2:50	**Section 8:** 2035 - 2050 Policy Drivers
2:50 – 3:00	**BREAK**
3:00 – 3:57	**Section 9:** 2035 - 2050 Solution Set
3:57 – 4:00	Close

40 minutes for Day 2 follow ups
55 minutes for each Section
- 15 mins consultant
- 40 mins discussion

Sample Agendas During ESMP Review (4 of 7)

Massachusetts Department of Energy Resources

October 26th

1:00 – 1:15	Administrative Items
1:15 – 1:55	**Section 7:** 5-Year ESMP
1:55 – 2:30	**Section 13:** Conclusion
2:30 – 2:40	**BREAK**
2:40 – 3:20	**Section 1:** Executive Summary
3:20 – 3:57	Overall Discussion of ESMPs
3:57 – 4:00	Close

~40 minutes for each Section

- 10 mins consultant
- 30 mins discussion

November 9th

1:00 – 1:20	Administrative Items Consultant Update
1:20 – 2:20	**Draft Recommendations:** Sec. 1 - 7
2:20 – 2:30	**BREAK**
2:30 – 3:30	**Draft Recommendations:** Sec. 8 - 13
3:30 – 3:50	Draft Revisions
3:50 – 4:00	Close

Draft Recommendations Review

November 16th

1:00 – 1:20	Administrative Items Consultant Update
1:20 – 2:20	**Final Recommendations:** Sec. 1 - 7
2:20 – 2:30	**BREAK**
2:30 – 3:30	**Final Recommendations:** Sec. 8 - 13
3:30 – 3:50	Final Revisions
3:50 – 4:00	Close

Final Recommendations Vote

Planning the ESMP Review Period (5 of 7)

ESMP Review Coordination & Consultant Role

- We will need to review all 3 EDC plans at the same time.
  - Anticipate asking the consultant to summarize, compare, and contrast the plans submitted by the EDCs. They will deliver a brief presentation to the GMAC at each meeting before opening discussion.
- The consultant will support with administrative tasks, coordinating review, summarizing ESMP drafts, summarizing comments, and tracking progress.

Gaining Consensus

- Plan to develop GMAC recommendations as sections are discussed.
- Recommend striving for consensus but not requiring 100% consensus on all recommendations

Guiding Questions For ESMP Review: Proposal (6 of 7)

To ensure certain overarching priorities are embodied throughout review, proposed are a set of questions the GMAC could consider as it reviews the sections of the ESMP drafts:

1. Does the ESMP section demonstrate **equity**, including increased transparency and stakeholder engagement in the grid planning process and an equitable distribution of impacts and benefits?
2. Does the ESMP section encourage **least-cost investments i**n the electric distribution systems or alternative investments, such as virtual power plants (VPP) and non-wire alternatives (NWA), that will facilitate the achievement of the statewide greenhouse gas emission limits and sublimits under chapter 21N?
3. Does the ESMP section **maximize net customer benefits and demonstrate cost-effective investments** in the distribution grid, including investments to enable interconnection of, and communication with, distributed energy resources and transmission-scale renewable energy resources, facilitate electrification of buildings, transportation, and other sectors?
4. Does the ESMP section **minimize or mitigate impacts on ratepayers** and reduce impacts on and provide benefits to low-income ratepayers?

Planning the ESMP Review Period (7 of 7)

Open Questions

- How do we organize a vote on GMAC recommendations? (In sections, full draft, each meeting, etc.)
  - We have the November meeting times to finalize recommendations, but can we advance this earlier?
- How should we balance a tight timeline and the need for thorough conversation?
- Should we pursue subcommittees given the ambitious timeline and goals?
  - Would need to consider Open Meeting Law requirements, scheduling restrictions, value add/be clear on subcommittee goals.
- What other questions or comments do ExCom members have?

Topic 1: DER Integration

- Current plans and activities of the Distribution Companies (10 minutes)
- Lisa Schwartz, Lawrence Berkeley National Laboratory (10 minutes)
- Baringa, Value of DER Study (10 minutes)
- Discussion

Distributed Energy Resource (DER) Integration



Michael Porcaro, PE
Director, Grid of the Future
nationalgrid

Jennifer Schilling
Vice President, Grid Modernization
EVERSOURCE ENERGY

Kevin Sprague
Vice President, Engineering
Unitil

Challenges & Impact of DER to the Electric system:

Variability: Resources such as Solar and Wind are highly variable, impacting grid power quality and system voltage.

Predictability: DER types such as Energy Storage can operate at any time, in both directions. Requires detailedd assessment of schedules and associated impacts. Potential implications on interconnection costs.

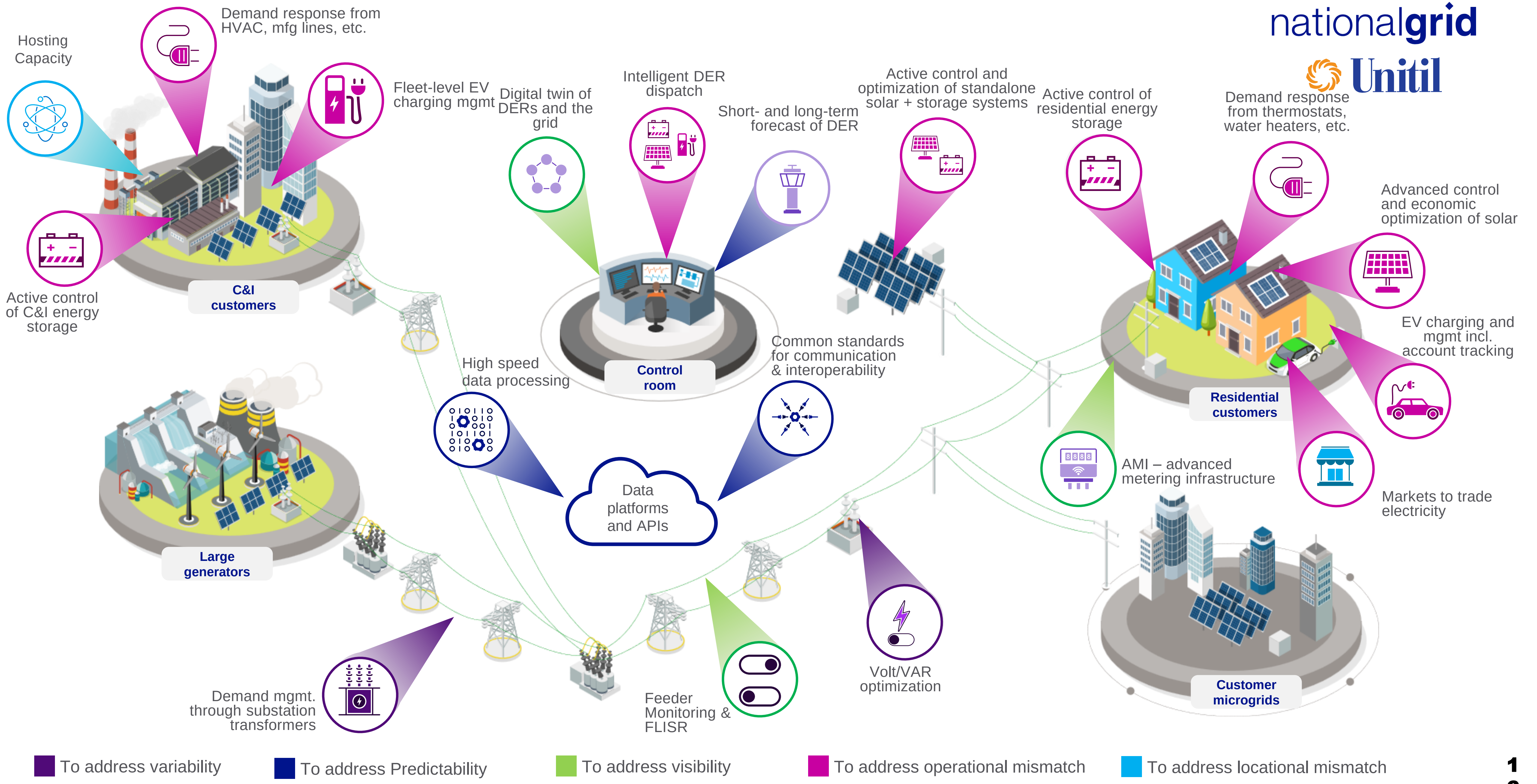
Visibility: The traditional electric system lacks the visibility to manage the operations of DER.

Operational mismatch: Resources are not always available when the system needs them. For example, in the phased approach of the CECP the peak is forecasted to be Jan 24th at 7am

Locational mismatch: Solar has been traditionally deployed where land is cheapest in areas typically low in load. Both technological and process solutions are likely to provided little value in such case.

Energy Demand: Under the Phased approach in the CECP, energy demand is likely to increase by close 2X. Technological, process and policy shouldn't be seen as an alternatives to wired solutions but rather as methods to optimize the system utilization.

Technological Improvements to Integrate DER



Congestion Management under FERC Order 22-22

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"small-scale power generation or storage technologies (typically from 1 kW to 10,000 kW)"…
"provide all services that they are technically capable of providing through aggregation"

- Fleet aggregation of resources for dispatch in energy markets will drive local congestion without EDC overview
- EDCs have to communicate availability of system resources and inform dispatch commitments
- EDCs must monitor real time changes in markets and, if system reliability is threatened, correct market commitment of resources

→ EDCs will act as conduit between wholesale markets and distribution located wholesale participation and aggregated resources.

	Condition	Action
Real Time	Immediate risk of system failure caused by **unforeseen** events	Utility control systems DMS and DERMS take control or coordinate with aggregators and DERs to manage constraints
Intra Day / Day Ahead	a) The distribution system is **constrained** requiring dispatch to mediate **or** b) There is **insufficient capacity** for aggregators to call all available resources	Utility provides guidance on dispatch limits
Intra Day / Day Ahead	a) The distribution system **does not require dispatch** to mediate a constraint **and** b) There is **enough capacity** for aggregators to call all their available resources	Aggregators have no limitations

Facilitating Interconnection – Dynamic DER Interface

OPPORTUNITY

- Impact studies identify opportunities to interconnect with constraints (e.g., off-unity power factor
- Absent direct communication and control of DER facility, constraints must be broadly applied

TECHNOLOGY

- Demonstrating Dynamic DER Interface technology to enable remote visibility and control at DER facilities that would enable more flexible interconnections
- DER Facilities with Dynamic DER Interface technology could establish operating guidelines with Eversource to limit constraints to certain hours

NEXT STEPS

- Technology demonstrated at one Eversource facility
- Recruiting customers in the impact study process to deploy technology and establish operating guidelines (in service by the end of 2025)
- Exploring use of technology for additional grid services use cases

Enabling DER as a Grid Asset

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Opportunity

Local *grid constraints due to capacity or voltage violations can be partially addressed with DER dispatch (utility scale or aggregated behind-the-meter)*

Technology Requirements

Grid operators with ***24/7 visibility and control of DER*** *can dispatch based on real-time system conditions (Dynamic DER Interface and control room upgrades)*

Operating Guidelines

Binding agreements are needed to establish DER dispatch rights and obligations

Value Proposition

DER providing grid services create value by avoiding operational measures or adding system flexibility

Grid Modernization Planning to Accelerate Deployment of Distributed Energy Resources

Lisa Schwartz

Presentation for Massachusetts Grid Modernization Advisory Council

August 10, 2023

This work was funded by the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

DER-related distribution planning elements (1)

- DER forecast
  - Types, sizes, amounts and locations
- Hosting capacity analysis
  - Maps show where interconnection costs will be low or high; supporting data provides details
  - Used for DER development, interconnection screens and distribution planning
- Grid needs assessment and non-wires alternatives* analysis identify:
  - Existing and anticipated capacity deficiencies and constraints
  - Traditional utility mitigation projects
  - A subset of planned projects that may be suitable for NWA — e.g., to defer or avoid infrastructure upgrades for load relief, voltage, reducing power interruptions, and improving resilience

**Non-wires alternatives* are DERs that provide specific services at specific locations to defer some traditional infrastructure investments, leveraging customer and third-party capital.

DER-related distribution planning elements (2)

- Programs to geotarget energy efficiency, demand flexibility (DF), distributed PV and storage, and managed electric vehicle (EV) charging to meet location- and time-dependent distribution system needs
- Grid modernization strategy and technology roadmap
  - Including investments needed to integrate, monitor and use DERs for grid services
- Proposals for pilots
  - Resilience projects (e.g., solar+storage, microgrids)
  - Time-varying pricing (e.g., for distribution charges, managed EV charging)

Figure 8. Measures creating the total demand reduction for the pilot

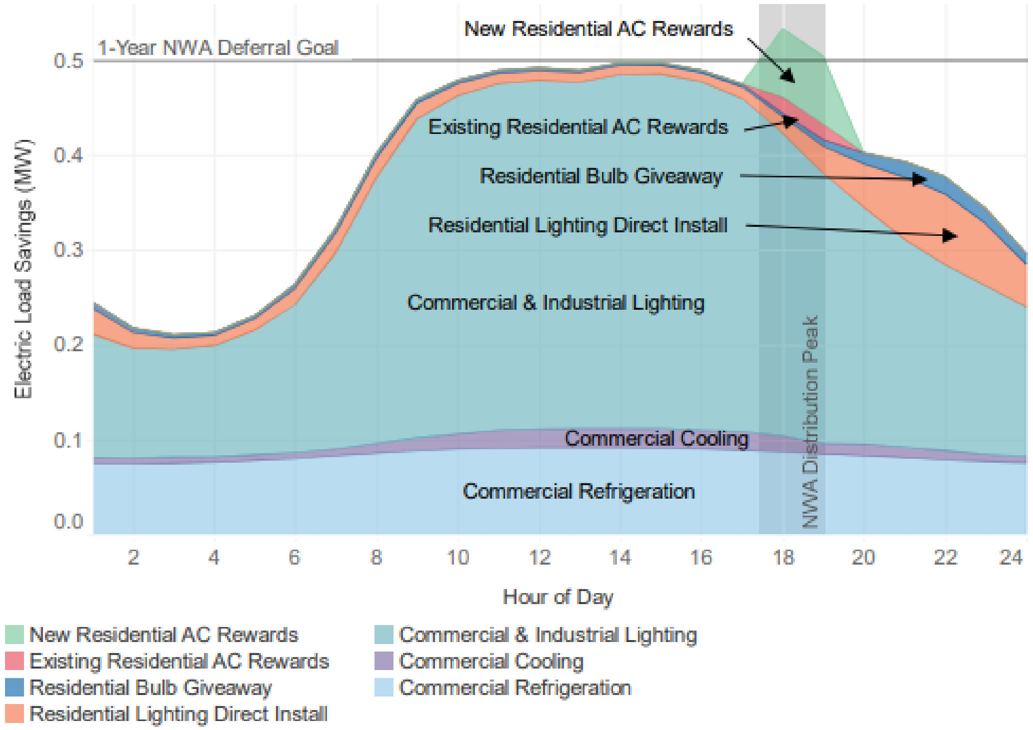

Figure source: CEE 2021

Example DER-related planning challenges & solutions (1)

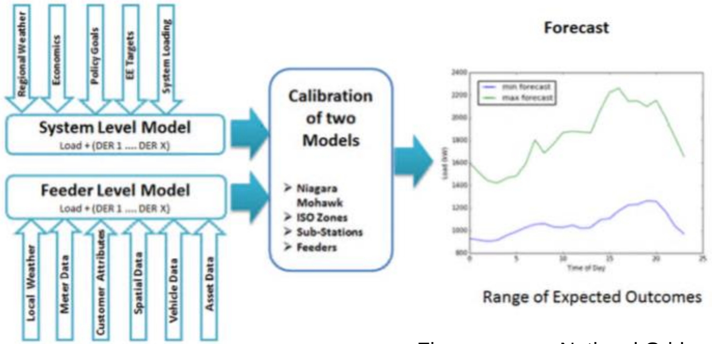

Figure source: National Grid

- Forecasting DERs and impacts for specific distribution system components/areas
  - Making DER forecasts spatially granular (e.g., by substation, feeder)
  - Incorporating DER program shapes
  - Incorporating EV forecasts — *forthcoming report on grid planning for vehicle electrification by Energy Systems Integration Group*
  - Disaggregating load forecasts to identify trends in individual end-uses and assess DER impacts on load profiles
  - ➢ *Solutions include using **end-use load profiles**; using **customer adoption models** to account for the impact of DER cost and performance, incentives, retail rates, peer effects, and customer demographics (Sigrin & Mills, 2020); **benchmarking** against 3rd party forecasts; probabilistic forecasting; and scenario analysis (e.g., electrification, high PV+storage)*
- Hosting capacity analysis
  - Costs (hardware, software, personnel)
    - For validating data inputs, improvements for modeling feeders, simulating power flows, and providing results
  - Accuracy
    - Data availability, validation, granularity (sub-feeder), model settings, update frequency
  - Typically only PV included, not other DERs — e.g., EE and DF can *increase* hosting capacity
  - Electrification usually not considered — except CA and MN require consideration of EV charging
  - Data redaction due to utility concerns about cyber/physical security — whether a bad actor can use information about line location, loads, or lines supplying critical facilities for targeted attacks
  - ➢ *But, locational data are available from other sources (e.g., Google Maps), and data alone is insufficient to carry out an attack and may not increase the risk of a successful attack.**

*Interstate Renewable Energy Council, *Key Decisions for Hosting Capacity Analysis*, 2021. Also see Synapse, 2021.

Example DER-related planning challenges & solutions (2)

- Consideration of proactive upgrades to increase hosting capacity
  - Cost allocation
- Non-wires alternatives
  - Insufficient quantity of viable bids to meet the utility's full need for any deferral opportunities
  - Long lead times for procurement
  - Often NWA don't pass cost-benefit test. Few DERs selected so far, but…
    - Examples of successful NWA projects in NY, CA, MI and MN*
    - Xcel Energy proposed changes to its NWA process for MN with stakeholder input.

Source: Con Edison BQDM Quarterly report, May 2022

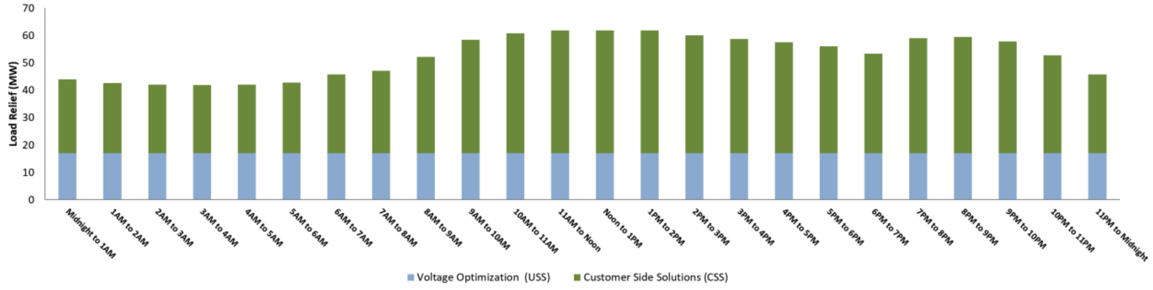

Figure 1: Hourly Load Profile of Operational BQDM Customer-Side Solutions and Non-Traditional Utility-Side Solutions. *Note: A 1.5 MW 4-hour utility-side battery energy storage system is not depicted in the load profile as its dispatch varies.*

Aspect/Component	Current Method	Proposed Method
Timeframe	Full NWA lifetime	**10-year deferral period***
Ownership Model	Utility ownership	**Load reduction contract or** utility ownership
Load Reduction Requirement	Exact MWh of load at risk on peak day	**Peak output for the duration of the risk**
Stacked Values	No stacked values	**Stacked values included**
Pro-Rating Values	No pro-rating, full values included	**Values pro-rated** for just the load reduction period (ARR split)
Solar Performance	PVWatts TMY simulation for one location in Minnesota	PVWatts TMY simulation for **five locations** in Minnesota

* Subject to change.

Table source: Jody Londo, Integrated Distribution Planning at Northern States Power Company — Minnesota, May 13, 2022.

*Schwartz and Frick 2022, Frick et al. 2021, DTE 2021, PG&E 2022 and CEE 2021

Integrating grid mod planning with other types of planning can reveal DER value and boost deployment

- With climate change planning — e.g., NY Distributed System Implementation [Plans](#)
- With electrification planning — e.g., [NV](#) and [MN](#)
- Across planning domains (T&D for MA) and strongly linking planning to *procurement, pricing and programs* — e.g., [Hawaiian Electric's 2023 Integrated Grid Plan](#)

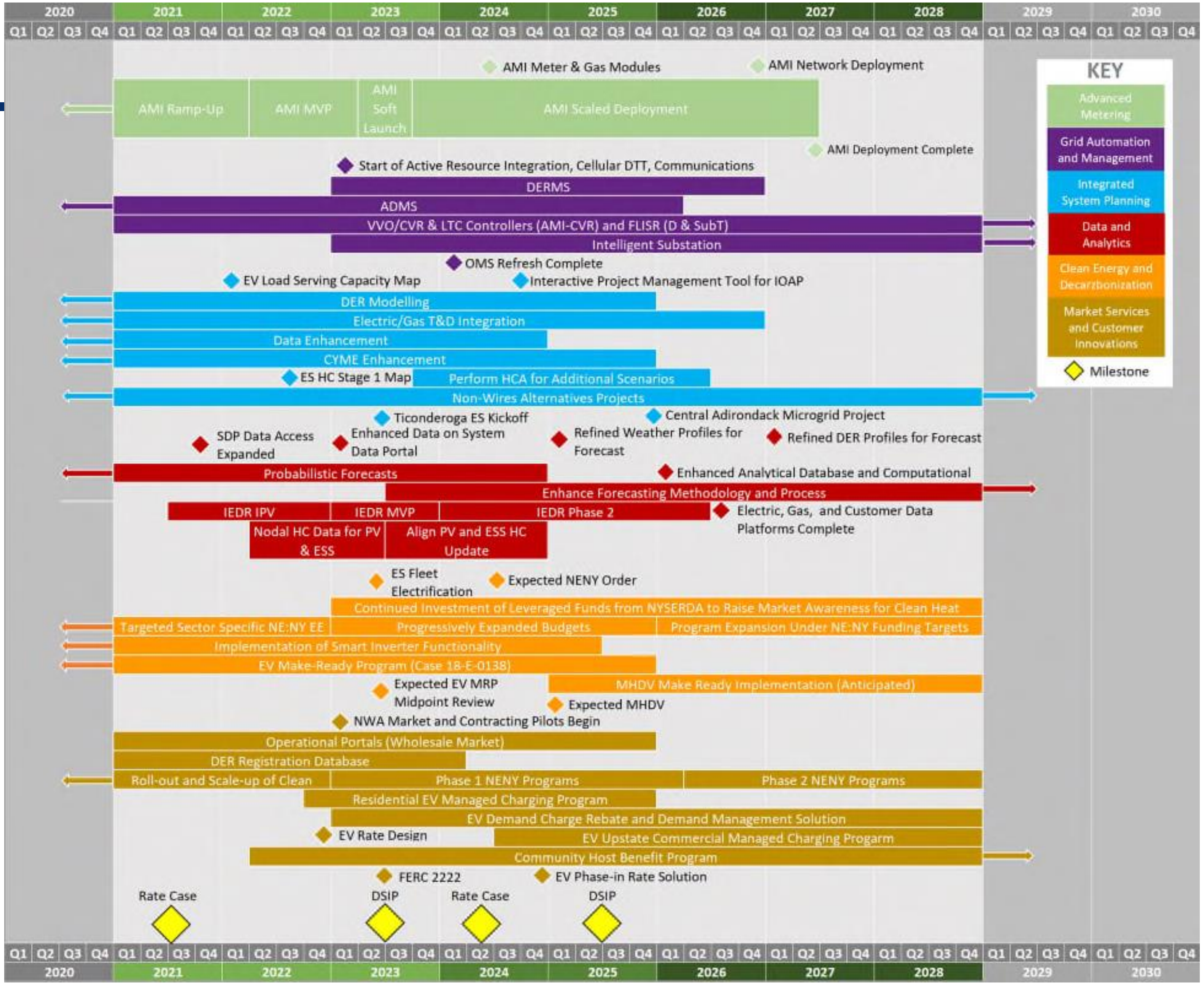

Figure source: National Grid Distributed System Implementation Plan ([June 2023](#))

Resources

Berkeley Lab's integrated distribution system planning website

U.S. Department of Energy, *Modern Distribution Grid*

Berkeley Lab and Pacific Northwest National Lab, Peer-Sharing Webinars for Public Utility Commissions on Integrated Distribution System Planning with NARUC, 2023

Berkeley Lab's research on time- and locational-sensitive value of DERs

L. Schwartz and N. M. Frick, Berkeley Lab, "State regulatory approaches for distribution planning," Presentation for New England Conference of Public Utility Commissioners," June 16, 2022

N. Frick, S. Price, L. Schwartz, N. Hanus and B. Shapiro, Locational Value of Distributed Energy Resources, Berkeley Lab, 2021

Center for Energy and Environment (CEE), Non-Wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot, 2021

DTE Electric Company, 2021 Distribution Grid Plan: Final Report, Michigan Public Service Commission Case No. U-20147, 2021

ICF International, Integrated Distribution Planning: Utility Practices in Hosting Capacity Analysis and Locational Value Assessment, 2018

B. Sigrin and A. Mills, "Forecasting Load on Distribution Systems with Distributed Energy Resources," Distribution Systems and Planning Training for Southeast Region, March 11, 2020

Pacific Gas & Electric, 2022 Grid Needs Assessment, California Public Utilities Commission proceeding R.21-06-017, Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future, August 15, 2022

Synapse Energy Economics, Inc., Hosting Capacity Analysis and Distribution Grid Data Security, 2021

Contact

Lisa Schwartz, lcschwartz@lbl.gov; 510-926-1091 (cell)

For more information

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MassCEC Value of DER Project Readout

Massachusetts Grid Modernization Advisory Committee

August 10, 2023

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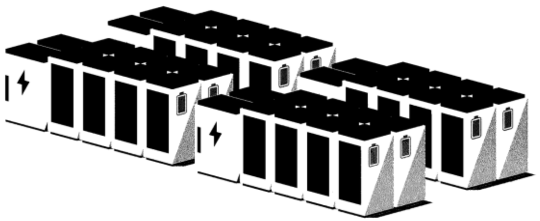
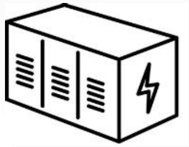
A Wide Range of Dispatchable DER Can Be Used To Enhance Grid Operation

The MassCEC "Value of DER" project focused on assessing the potential value of dispatchable DER by creating an integrated set of frameworks spanning Cost/Benefit, Operational, and Compensation components.

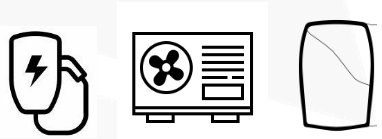
Focus of Initial MassCEC Project



- Single site >500kW Dispatchable DER
- Standalone without associated load



- Multiple 50 – 500 kW Dispatchable DER
- May be located "behind the meter" at larger commercial sites



- 10 – 50 kW Dispatchable DER
- Small commercial or residential sites on individual feeders

Control Approach / Execution Risk

Direct ← → Economic

Resource Diversity / Concentration Risk

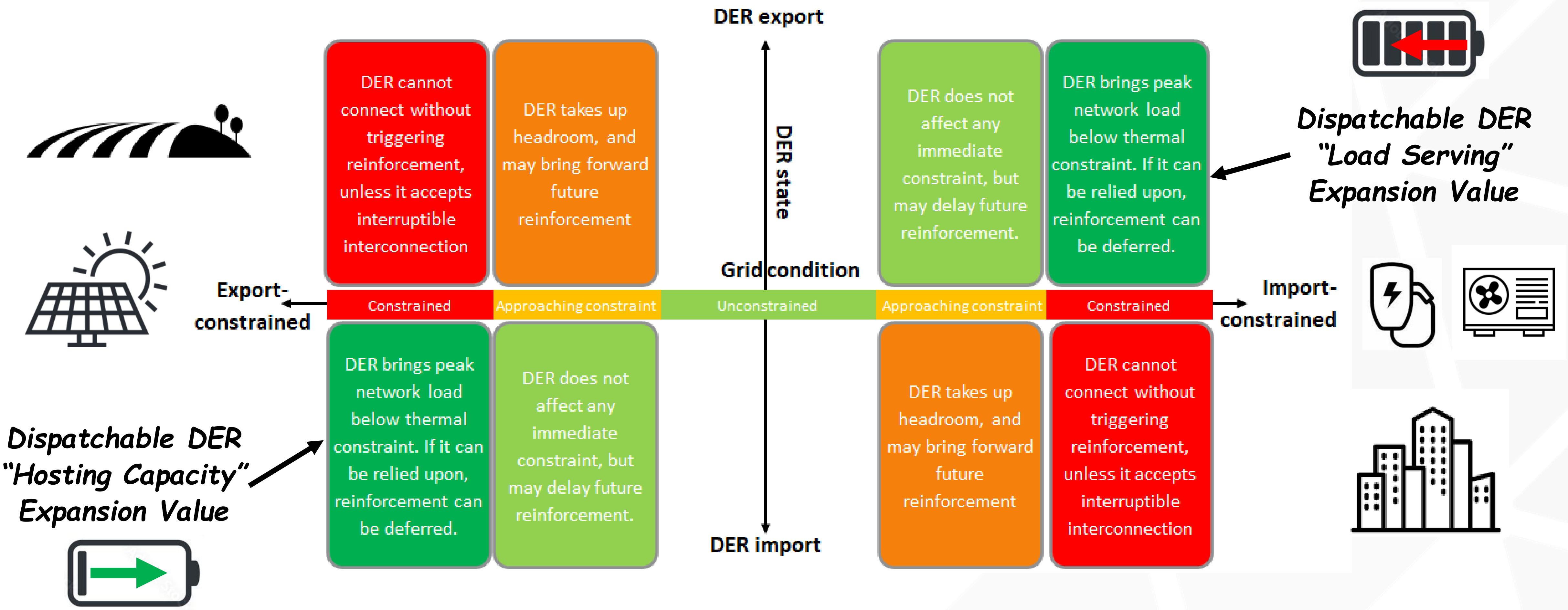
Concentrated → Diverse

Primary Economic Driver for Participation

Connection Speed & Cost Reduction/Capacity Revenues | Energy Savings/Demand Charge Avoidance

Dispatchable DER Can Provide Benefits to Alleviate Network Constraints

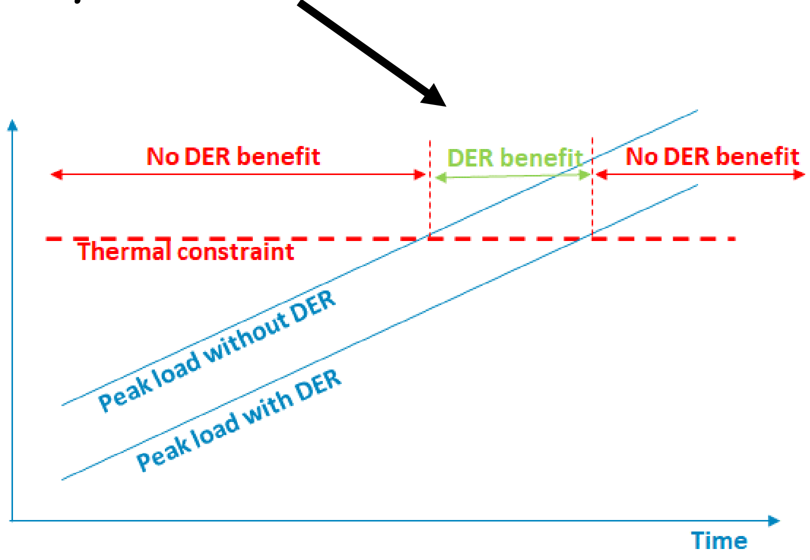
Reliable, dispatchable DER can provide benefits for both distribution networks experiencing import constraints from increases in loads, and distribution networks experiencing export constraints from increases in passive distributed generation. “Thermal” constraint reduction represents the largest benefit dispatchable DER can provide to grid operations.



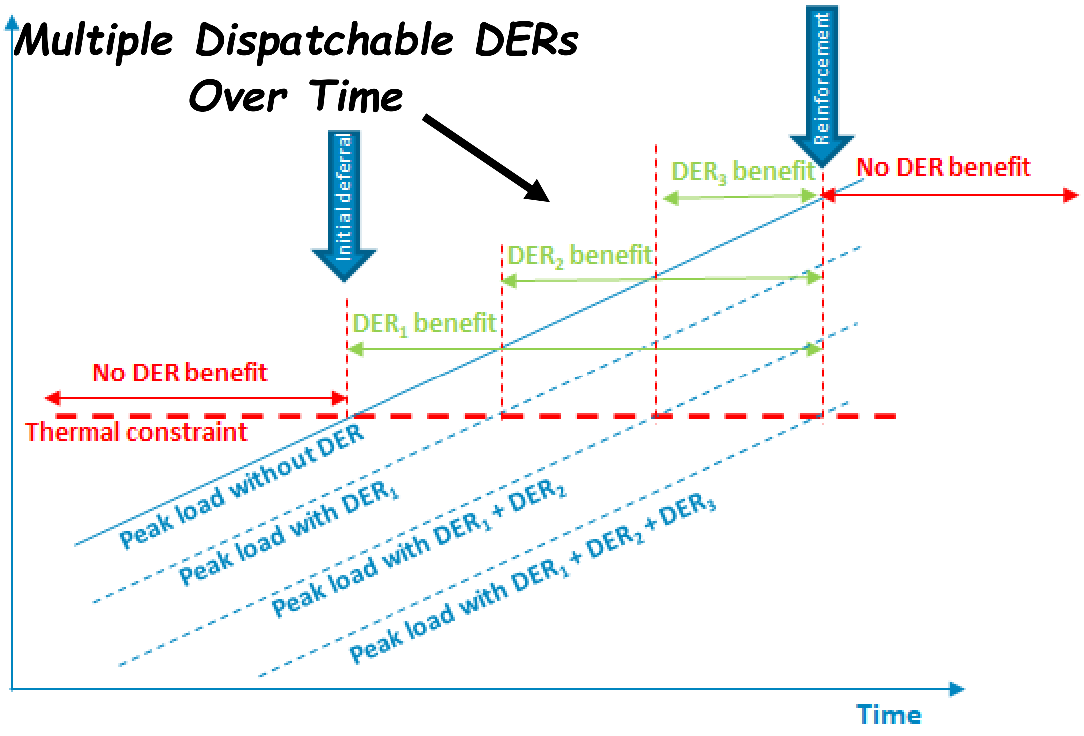
Dispatchable DER Provide An Incremental Option To Grid Reinforcement

One of the largest benefits of dispatchable DER compared to traditional grid reinforcement is the ability to add capacity incrementally and in smaller purpose-fit blocks

Single Dispatchable DER solution



Multiple Dispatchable DERs Over Time



There will always be sections of the distribution network where the pace of load growth or distributed generation growth requires traditional grid reinforcement. In contrast, Dispatchable DER solutions may provide the most value on networks with slower capacity growth needs, or where network needs are uncertain as a temporary solution to address less predictable network constraints.

Baringa

Key Findings from Analysis

There were key conclusions that were drawn within each of the three frameworks that inform fundamental components of a market for dispatchable DER at the distribution level

Benefit & Cost Framework	Operational Framework	Compensation Framework
• Focus on peak load (and excess distributed generation) reduction for thermal constraints • The value of DER can be realized as a step change over time • Establish capacity factor benchmarks for different types/sizes of dispatchable DERs to compare to traditional grid reinforcements	• Understand operational limits for accessing value of flexibility • Develop hierarchy of grid needs to resolve conflicts. Prioritize distribution grid needs where fewer alternative dispatch solutions exist • Develop and coordinate activation principles with other parties who utilize dispatchable DER (e.g., ISO-NE)	• Drive product definitions (spanning capacity, energy and reserves constructs) based on network needs • Develop common frameworks for assessing interconnection and operations costs and compensation • Design compensation to enable appropriate co-participation and revenue stacking • Assess reliability as a primary driver to contextualize compensation methods

MassCEC and project stakeholders are refining and evaluating two potential optional demonstration pilots to test concepts from the Value of DER project in real-world, circuit-specific scenarios that incorporate these key findings.

Break

Please be ready to start again in ~10 minutes at 2:25

After the break…

- *Topic 2: Cost Allocation*
- *Public Comment*
- *Close and Next Steps*

Topic 2: Cost Allocation

- Distribution Companies (15 minutes)
- Ron Nelson, Strategen (15 minutes)

DER Cost Allocation

August 10, 2023

EVERSOURCE nationalgrid Unitil

Agenda

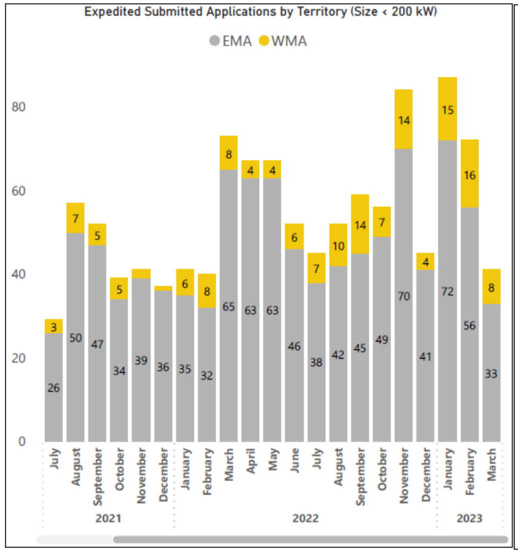
1. DER Planning Evolution (Eversource)
2. CIP Proposal Background (Eversource)
3. CIP Summaries (Eversource and National Grid)
4. Principles for Sound Cost Allocation (National Grid)

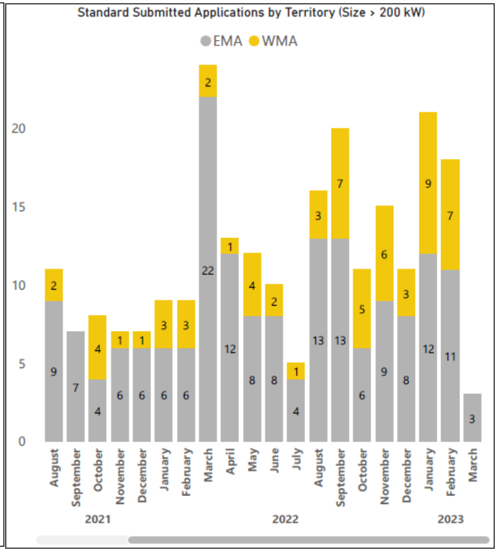
DER Planning Evolution

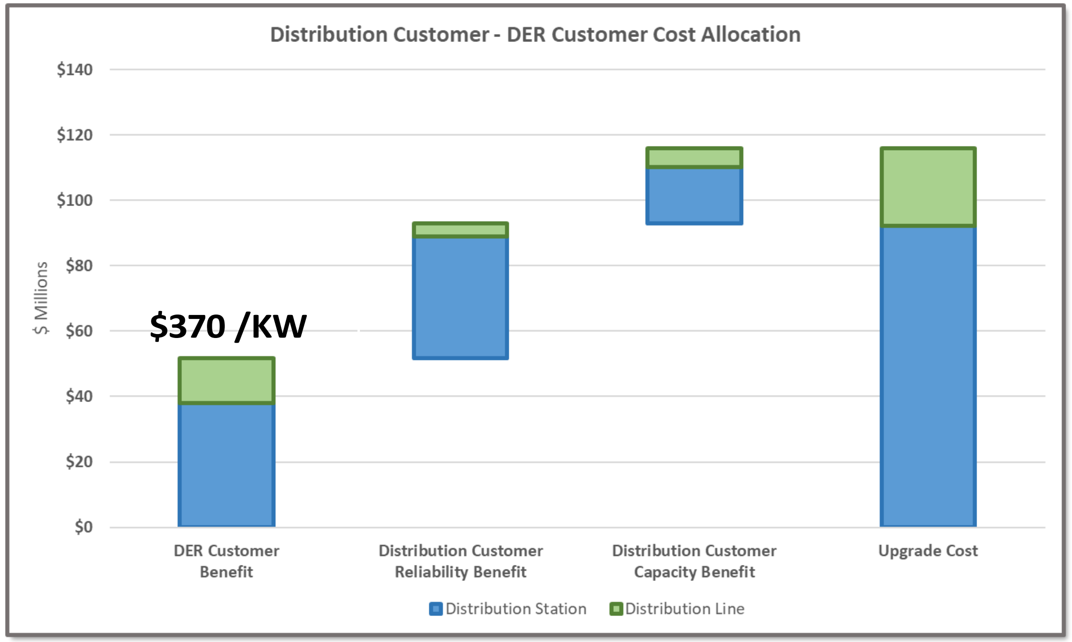
- Interconnection Studies: Volumes driven by state incentives continue to increase
  - **1st Step:** Bifurcate applications based on size, type and study complexity: DPU created Simplified, Expedited and Standard processes
  - **2nd Step:** But majority of the capacity leans toward large ground mounted (standard applications): DPU approval for Group Study construct
  - **3rd Step:** Automated tools to assess steady state and transient impacts of interconnection requests – DPU Approval of 2025-Grid Mod Funding

- But study process efficiency did not address the main issue – cost-causation based assignment of substation upgrade costs to a few DER customers

- **DPU 20-75-B Cost Allocation:** First-in-the-nation methodology based on equipment design – equitably allocating costs of infrastructure upgrades between Distribution customers and DER customers.
  - Eliminates Interconnection cost hurdles and Significantly scales DER growth
  - Fixed Fee for 20 years – Eliminates Developer Uncertainty
  - Eliminates Free Rider Issues
  - Differentiated Fees represent geographic uniqueness and price signals to maximize DER growth aligned with hosting capacity
  - Cost allocation to distribution customers based on demonstrable operational reliability benefits







What is a Capital Investment Project “CIP” Provisional Program?

First-in-nation approach to share upgrade costs that benefit both Distribution Customers and DER Customers

Establishes a fixed cost per kW fee for 20 years

Upgrades establish future capacity instead of short-term fixes

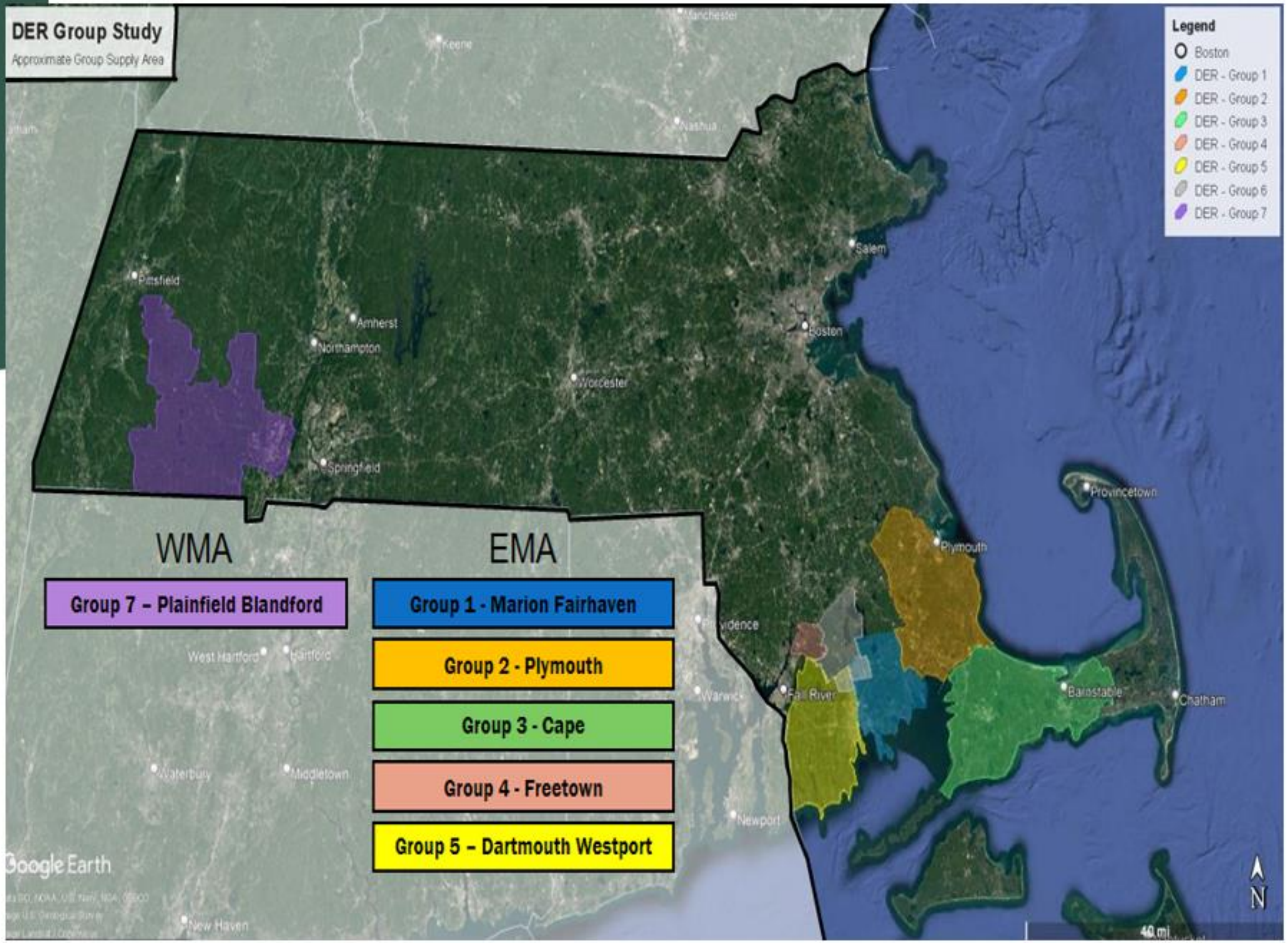
Eliminates "free riders" from having others pay for upgrades through the cost causation principle

CIP Summary Table Results

Revised 05-19-2023								
Group	Name of Group	# of Substations Impacted	Exist Customer Load (MWs)	Installed DER (MWs)	Proposed DER (MWs)	# of Applications	CIP Fee Dollars/kW	Future Enabled DER (MWs)
1	Marion-Fairhaven	4	57	69	45	14	$370/kW	91
2	Plymouth	7	217	236	118	37	$224/kW	245
3	Cape	8	461	149	71	57	$357/kW	225
4	Freetown	1	8	13	22	6	$490/kW	30
5	Dartmouth-Westport	2	64	72	16	4	$387/kW	44
6	New Bedford	1	46	65	48	14	N/A	N/A
7	Blandford-Plainville	1	11	25	13	3	$498/kW	28
		24	864	630	333	135		663

Group 1 is DPU approved and Groups 2 through 7 are pending DPU decision

CIP Geographic areas approved or under current review



Marion-Fairhaven CIP Approved

Approved by DPU on December 30, 2022

Total Cost of Transmission and Distribution System Upgrades ~$120M

ISAs issued to Group Members and partial payments collected

Eversource in design phase for next 12 to 18 months

Smaller Expedited Projects now moving forward with approval from DPU

CIP Fee $370/kW plus local interconnection costs

Marion-Fairhaven CIP (22-47)
Transmission Upgrades:
(4) Substations Impacted (654, 646, 745, 624) (3) Substations requiring upgrades (645, 745, 624)
Distribution Upgrades:
(2) New Feeders (total 41,900 feet) (2) Existing feeders reconductored (36,700 feet)

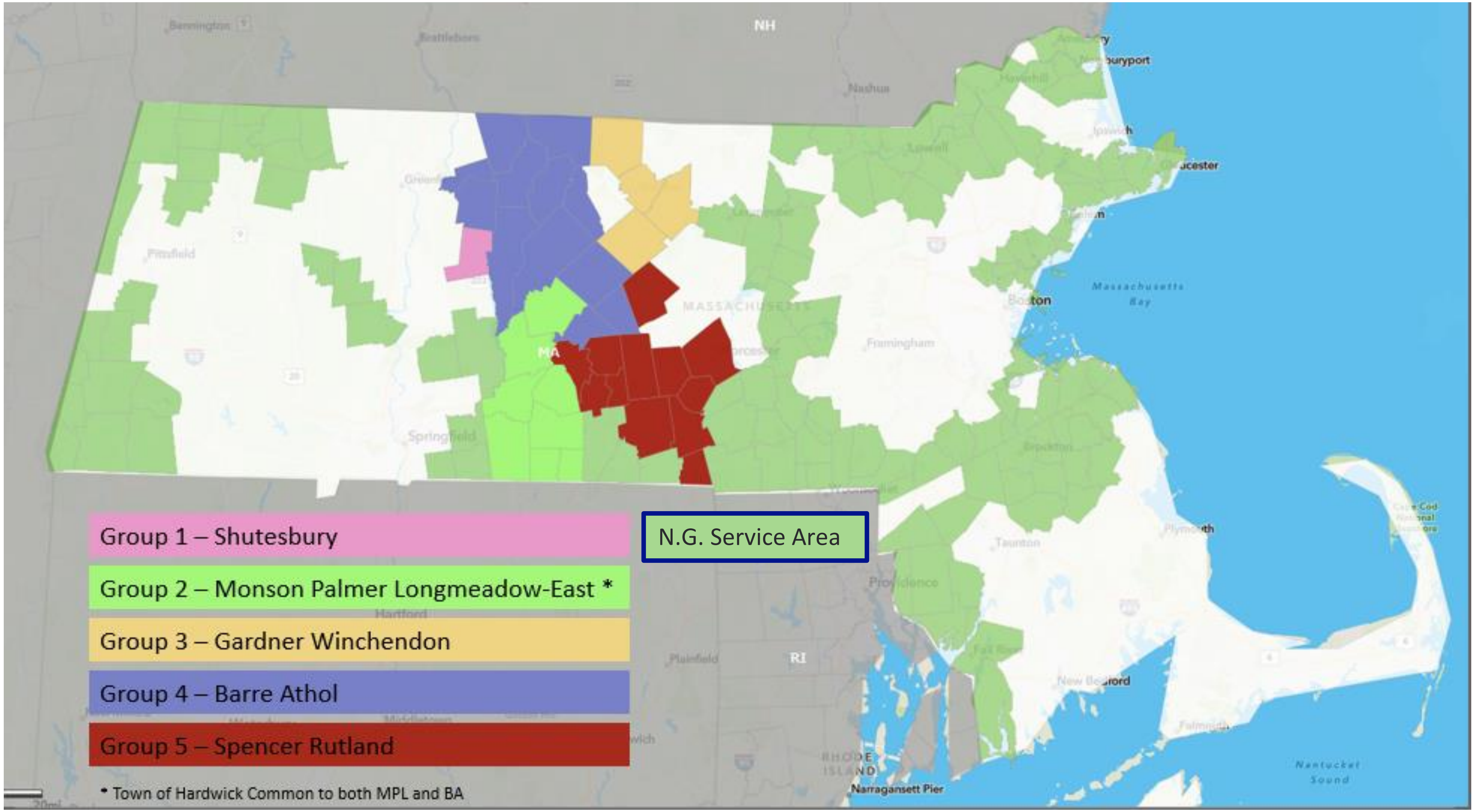
National Grid

National Grid Proposed CIP Areas

	CIP Name	# of Substations Impacted	Proposed Group Study DG (MW)	# of Applications	CIP Fee (Dollars/kW)	CIP Enabled DG (MW)
1	Shutesbury	1	20	5	$418.11	30
2	Monson-Palmer-Longmeadow (East)	3	17.8	7	$432.70	79
3	Gardner-Winchendon	5	47.9	8	$327.09	54
4	Barre-Athol	4	62.6	10	$617.71	75
5	Spencer-Rutland	7	82	16	$574.35	100
	Total	20		46		338

- National Grid's CIPs (pending approval) will enable $232 million in investment creating 338 MW of DG hosting capacity, 107 MW of which is additional to Study participants
- Approximately 70% of costs are allocated to CIP Fees, and 30% to load customers
- Unitil has no CIPs and is not active in CIP proceedings

National Grid Five Provisional Program CIP Areas



Principles for Evolving a Cost Allocation Approach

The Commonwealth's future cost allocation approach should build on the successes of the CIP framework and be rooted in the following principles. Proposals on the paths to achieve this evolution will be included in National Grid's ESMP.

Principle	Detail
Costs allocated based on benefits received and created	• **Spatial:** Interconnection fees commensurate with upgrade costs based on specific geography – costs will be lower for DG sited close to load. • **Temporal:** First movers and subsequent customers share costs fairly • **Customer type:** DG and load customers alike contribute fairly to capacity costs.
Stable and predictable capacity prices	• Developers require up-front understanding of capacity prices and expectation of price stability. New load customers seek this as well.
Rooted in system engineering approach	• Framework and price signals should support and derive from sound anticipatory planning, and physical infrastructure availability
Administrative simplicity	• Adjudicatory process should be as streamlined as possible to approve prudent investments and speed interconnections—building on learnings from provisional CIPs.

Appendix

Questions

Provisional Program Overview - Eversource

- **D.P.U. 17-164:** On April 8, 2020, the Department order allowed Eversource to group DERs connected at saturated stations to develop comprehensive solutions

- **D.P.U. 19-55:** Eversource is one of six entities who have proposed alternative cost allocation proposals

- **D.P.U. 20-75:** Eversource proposal is to group DER applications at the substation level first

- **D.P.U 20-75-B:** New guidance provided by DPU to address interconnection of DER in the existing Groups via new provisional program framework

- **DPU-22-47:** Order for the Marion-Fairhaven Group Approved on December 30 2022

- **DPU 22-51 to 22-55:** Completed last DPU hearing in Feb 2023; final order expected by Q3 2023

Resources:

- **Distribution Group Studies – Eversource:**
  - Distribution Group Studies | Eversource
  - Frequently Asked Questions (FAQs) - PDF
- **Provisional System Planning Program Guide – Mass.gov**
  - Provisional System Planning Program Guide | Mass.gov
- **Provisional Program Filings - Eversource:**

Case Number	Group Study	Reference
DPU 22-47	Marion-Fairhaven	D.P.U 22-47 – Exhibit Engineering Panel 2
DPU 22-51	Freetown	D.P.U 22-51 – RR-DPU-ES-1(c)
DPU 22-52	Plainfield-Blandford	D.P.U 22-52 – RR-DPU-ES-1(d)
DPU 22-53	Dartmouth-Westport	D.P.U 22-53 – RR-DPU-ES-1(e)
DPU 22-54	Plymouth	D.P.U 22-54 – RR-DPU-ES-1(f)
DPU 22-55	Cape	D.P.U 22-55 – RR-DPU-ES-1(g)

Distributed Energy Resource (DER) Cost Allocation

Ron Nelson, Senior Director

Eli Asher, Manager

Grid Modernization Advisory Council | August 10, 2023

Presentation Structure

- Objective
- When does cost allocation happen
- Traditional cost allocation (i.e., for load/importing customers)
  - Line extensions
  - Rate increases
- DER cost allocation
  - Approaches to allocate costs through traditional interconnection process
- Export tariffs

Objectives

- The purpose of this presentation is to provide the Grid Modernization Advisory Council (GMAC) with a high-level overview of DER cost allocation approaches across various jurisdictions, including:
  - An overview of how electric power system costs are allocated today;
  - A discussion of the Cost Causation and Beneficiary Pays principles, and their inter-relationship;
  - The primary issues associated with utilizing only traditional cost allocation methods; and
  - How various jurisdictions are attempting to minimize these concerns through alternative methodologies.

When Does Cost Allocation Occur?

- Connection of load
  - Line extension tariffs have guidelines on what connecting load pays to connect to the system
    - For example, a large commercial customer may trigger a substation upgrade as well as local facilities. The customer would pay for customer-specific connection costs (e.g., a dedicated local transformer) but only a portion, if any, of the substation upgrade. The substation upgrade would be socialized and collected through the general rates. The reasoning is that the large customer will eventually (e.g., in 20 years) pay off the substation costs and contribute to other joint system costs.
- Connection of exporting facilities (i.e., DER)
  - Interconnection tariffs have guidelines on how costs are allocated and collected. Some common forms are Single Facility Causer Pays, Group Study Causer Pays, and some jurisdictions are evaluating Beneficiary Pays where costs are shared across all interconnecting DERs and/or with ratepayers.
- When rates change through rate cases
  - Cost of service study inform intra and interclass cost allocation and informs rate designs through unit cost calculations

Traditional Cost Allocation Overview

- Traditional cost allocation occurs between utility customers, often within a rate case, and is based on cost causation. Traditional cost allocation is the division of the utility revenue requirement across utility customers and "customer classes".
  - Typical classes include Residential customers, Commercial and Industrial (C&I) customers, Agricultural customers, and Street Lighting customers.
  - Through on a Cost of Service Study (COSS), costs are assigned to these customer classes to inform the revenue requirement by class.
  - Rates are then set based on the class revenue requirement, the COSS cost estimates, customer and class load characteristics, and other relevant information.
- Cost causation is a principle that attempts to identify customer and class characteristics that cause costs on the system and allocate said costs to that customer or class. Assigning costs on cost causation is intended to minimize costs on the system by sending efficient price signals.

Traditional Cost Allocation

Breakdown of an ECOSS

+ The first step, Functionalization, refers to the mapping of traditional utility costs (e.g., poles & wires) to the power system functions served by those costs (e.g., distribution, transmission, customer).
+ The second step, Classification, refers to the mapping of functions or subfunctions as being caused by one or more categories of factors (e.g., demand, energy, or customer)
+ The third step, Allocation, refers to applying an allocation factor to each cost category. Energy and demand allocators are based on customer or class load characteristics. Modern approaches focus on time-based load characteristics.

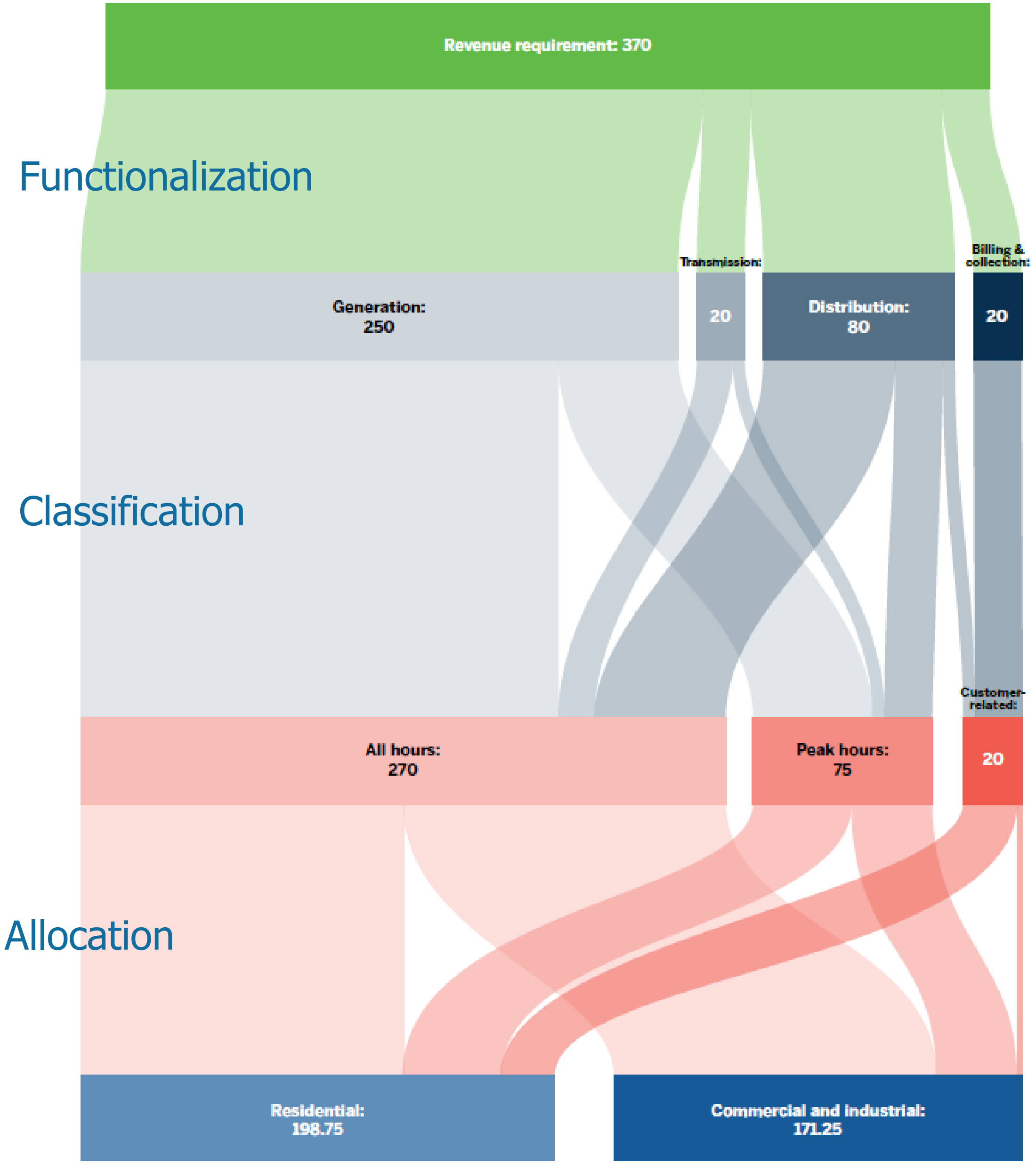


Image source: Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project.

The Importance of Cost Causation and Allocation

- The more granularly we understand cost causation, the better we can design rates and programs to lower system costs and control rates for ratepayers.
  - Energy and capacity charges should reflect various load characteristics, such as peaks, time-of-use, interruptible characteristics, and diversity.
- As technology advances, cost causation changes and rate designs must evolve.
  - E.g. DERMS, VPPs, EVs.
- Traditional cost allocation has been used to equitably assign costs to and collect revenues from utility customers for over 100 years.
  - DER cost allocation is largely not reflective of the cost allocation approach used by utility customers.
- Cost causation and allocation are generally applied consistently in rate cases and line extensions (i.e., existing and connecting customers are treated similar)
  - DER cost allocation is not aligned with line extensions or rate case cost allocation

DER Cost Allocation – A Paradigm Shift and Resulting Issues

Use of only the Causer Pays principle creates inequity among DER owners:

Interconnection pathway

Cost Allocation issues

DER(s) seeking interconnection

Non-POI Costs

Requires system upgrade, DER pays 100%

No system upgrade required, $0

Excessive costs in a saturated system

No price signals

Can potentially be prevented with flexible interconnection

Free ridership

DER Cost Allocation

+ Most DER cost allocation requires one upfront payment from the connecting DER
  + This differs from how load customers treatment
+ There are systematic issues with the Causer Pays approach and the interconnection process in general.
  + It is reactive in most states. Utilities do not proactively plan for DERs because exporting facilities are not treated as customers, nor are they allocated costs in a similar fashion.
  + It leads to saturation of the system, which then requires significant upgrades and high costs to interconnect additional DERs.
  + It does not incentive efficient utilization of system hosting capacity through price signals or export services (e.g., curtailment, seasonal limitations)
+ The issues with Causer Pays has led to various other approaches to DER cost allocation/interconnection.
  + Group/Cluster interconnection studies – shared cost allocation (e.g., California, Massachusetts).
  + Renewable energy zones (e.g., Illinois and Maryland). Illinois and Maryland are either developing or discussing these concepts but neither has addressed cost allocation.
  + Beneficiary Pays (commonly used for load), whereby costs are distributed among beneficiaries regardless of whether they are the direct causer of the costs. (e.g., Maryland).

How Regulators are responding

- Recognizing the near-term problems associated with existing cost allocation methodologies, regulators are considering alternative methodologies and the possibility of sharing costs with distribution customers, effectively offsetting costs for DER owners.
- In addition to treating DERs and load symmetrically via export tariffs, other jurisdictions have explored alternative pathways, including but not limited to:

Proportional Beneficiary Pays that apportions out the cost of grid upgrades to future DER proportionately according to their load profile

Use of Hosting Capacity scarcity to send price signals that incent DER owners to deploy DERs where it would most benefit the grid

Integrated Distribution System Planning that considers DERs in distribution planning, which can be paired with export tariffs for DER owners

Using export tariffs can create symmetry in DER and load treatment

- As we have shifted to a bi-directional system with two-way power flows, ratemaking for load (i.e., import) and DERs (i.e., export) have continued to be treated differently.
- However, exporting facilities cause costs just like load customers, and should be treated symmetrically, through use of export tariffs.
- The costs DERs cause on the system can often be mitigated and better controlled through advanced technologies (smart inverters, DERMS, etc.) and flexible interconnection/export tariff options that provide DER customers with optionality to limit and/or curtail their export.
  - These strategies and technologies can influence load profiles and mitigate grid constraints that would otherwise drive costs.
  - This structure is no different from load management procedures that have become increasingly widespread in recent years.

Export Tariffs represent a shift in the role of the distribution system

- Export is a core service of the distribution system
  - The distribution system needs to be planned for export demand and forecasted growth, mirroring system planning expectations for serving load.
  - Regulator oversight and authority over utilities' export service planning should provide transparency into utilities' long-range plans and investment to serve customer exports.
- Cost of Service extends to the cost of serving customer export
  - Methods for valuing exports and/or curtailment of customer exports are standardized and reviewed.
- The value of customer exports informs decisions on export related investment
  - Curtailments and limitation of customer export is acceptable when the cost of providing additional service exceeds the value of the service provided. This is analogous to reliability planning for serving load.

Export Tariffs drive efficient grid utilization

- Costs of exporting service are paid by all exporters.
  - Exporting facilities can be incorporated into traditional regulatory process, alongside the rates for customer consumption, and reflect both costs to serve exports and the value of receiving those exports to the grid.
  - Rates should reflect long-term marginal costs and the time variable nature of serving and receiving customer exports.
- Exporters respond to export pricing
  - Properly designed export rates align export customer incentives with grid capability
  - When customers maximize their export value (or minimize export costs), fewer investments are needed to serve customers
- Utilities are incentivized to provide low export rates and high-quality service
  - Flexible interconnection, such as active network management, allows more DER to share the same infrastructure, reducing export rates.
  - Proper planning minimizes interconnection issues and service costs.

Residential two-way tariff	Time period
Fixed charge	Daily
Peak consumption charge	4 pm – 9 pm
Shoulder consumption charge	9 pm – 10 am
Off-peak consumption charge (solar sponge)	10 am – 4 pm
Export peak rebate	4 pm – 9 pm
Export charge* applies to exports > 2 kWh/day (that is, the basic export level is 2 kWh/day).	10 am – 4 pm

Image source: Australian Energy Regulator, Export Tariff Guidelines (May 2022)

STRATEGEN

Appendix

A Comparison of Select Modern Interconnection/Allocation Strategies

States	New York (Standard)	New York (Pilot)	Maryland	Maryland / Illinois
Model	Hybrid – CP/BP	National Grid "Field of Dreams"	Beneficiary Pays + Scarcity-based Hosting Capacity (HC)	Renewable Energy Zones a.k.a. DER Ready Areas
Detail	Causer pays 100% upfront, proportionally reimbursed by future DERs	Proactive utility buildout, reimbursed by future DERs and/or customers	Fees determined based on locational scarcity of HC across system, DERs pay proportional amount of HC used. First movers (cost causers) pay higher fees	Targeted proactive utility buildout
Who Pays	DERs	DERs, Customers	Cost allocation not determined	Cost allocation not determined
Notes/ Issues	High upfront costs for causer	Cost differential recovered through customers	Proposal does not determine cost allocation for ratepayers	Unclear approaches to cost allocation & process to determine location of upgrades

*These strategies have been implemented or are under consideration in these jurisdictions

Massachusetts Department of Energy Resources

Public Comment

- 30-minute period for public comment
- Time limit of 3 minutes per comment

Close and Next Steps

- Next Executive Committee Meeting: August 25, 2023, 2:00 – 3:30 PM
- Next GMAC Meetings:
  - September 14, 2023, 1:00 – 4:00 PM
  - Proposed: September 28, 2023, 1:00 – 4:00 PM

- ESMP review
  - Draft ESMPs will be posted on the GMAC website as soon as received on 9/1.
  - The GMAC will have 80 days to review the draft ESMPs from 9/1/23 – 11/20/23