INAUGURAL CONVENING REPORT

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Prepared by the CHARGED Steering Committee and Implementation Team

charged
Charting a path for Greater Electrification on the Distribution system

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* DISCLAIMER

The views contained in this report do not represent the views of any of the Participant's organizations and cannot be attributed to any single Participant. The Convening discussions presented in the group chapters reflect a synthesis of Participant views. The Convening discussions do not represent a consensus view of the individual Participant or the Participant's organizations. Participants engaged, primarily, in discussions with their assigned group and interacted with the other groups during plenary sessions.

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INTRODUCTION

MOTIVATION

There is broad consensus that successfully addressing the climate crisis will require electrification of the transportation and building sectors. Recognizing this need, some cities and states have begun to adopt electrification policies. Ensuring that the electric distribution system is ready for this future in a way that maintains customer affordability, reliability of the distribution system, and is done in an equitable way is one of the most important tasks for a successful energy transition.

Achieving electrification in an affordable, reliable and equitable manner requires a thoughtful approach. Many utilities have been operating under a no or low load growth paradigm for the last few decades. As such, these utilities may not have the tools, systems, or experience to be able to manage load growth driven by transportation and building electrification in a way that (1) allows for rapid connection of new loads, (2) manages costs and maintains or even reduces average rates, (3) and minimizes cost shifting between customers, especially to lower-income customers. To illustrate the magnitude of potential distribution system costs for electrification, a study commissioned by the California Public Utilities Commission (CPUC) and conducted by Kevala estimated that about $50 billion of distribution system investment would be required by 2035 to accommodate a high electrification future.[1] This estimate was grounded in the scenario that active measures are not taken to mitigate cost increases and manage load. Where electricity rates are already high (such as in California), additional rate increases have the potential to slow down electrification and discourage customers from adopting electrification measures.

While California may be an outlier, it is a reminder that unless properly planned, utilities may incur unnecessary and avoidable cost increases while undergoing this transition. Fortunately, there are solutions that can better accommodate new loads in ways that minimize new infrastructure costs. In fact, a subsequent study to the Kevala study, by the Public Advocates Office of the CPUC, estimated that those costs could be cut by about half if load management solutions were employed.[2] This highlights how load management tools have the potential to offset distribution infrastructure costs, when integrated into planning processes.

In jurisdictions where utilities have started to pivot towards electrification, efforts have focused on multiple issues—distribution system planning for new loads, processes to connect new loads to the grid, incentives and programs that encourage electrification and consumption patterns that minimize impacts on the grid, and distribution system operating procedures. However, these efforts are early and multiple challenges remain. All solutions have tradeoffs and ultimately utilities, regulatory commissions and stakeholders will need to find those solutions that multiple parties can agree on.

1 Kevala, 2023, *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*, docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF

2 The Public Advocates Office, California Public Utilities Commissions, 2023, *Distribution Grid Electrification Model: fact sheet*, publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230824-public-advocates-distribution-grid-electrification-model-fact-sheet.pdf

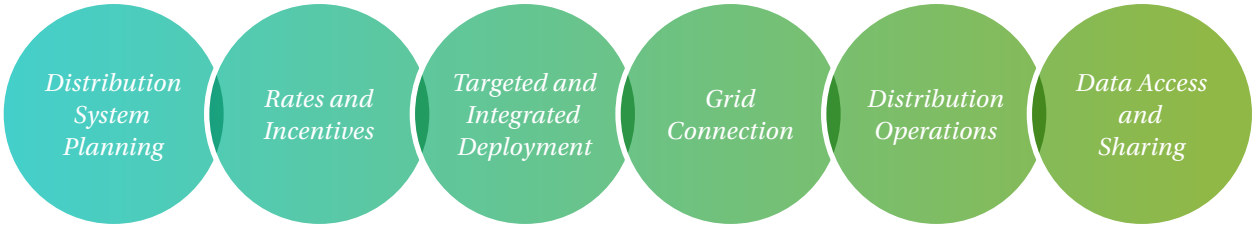
OVERVIEW OF THE CHARGED INITIATIVE

CHARGED seeks to facilitate a coordinated and national level conversation to support effective and efficient regulatory and technical change of the electric distribution system across the US. The initiative aims to identify tools and methods that utilities across the United States can adopt to enable electrification in ways that minimize infrastructure costs and maintain system reliability. While CHARGED does not aim to identify a single "standard", it aims to help the industry move beyond the current state-by-state piecemeal approach to utility planning and operations for electrification. The underlying principle is that processes that bring utilities, technology providers, and public interest groups together in collaborative ways can generate creative and effective solutions that will help utilities and states across the country to learn from each other and accelerate the adoption of effective practices.

CHARGED takes a holistic approach that recognizes the importance of multiple utility functions and their interconnectedness, as well as the growing role of utility customers and advanced energy solutions providers in meeting shared objectives around electrification. The initiative includes the following workstreams.

1. **Distribution system planning** includes issues such as load forecasting, technology characterization, multi-hour analysis/modeling, flexibility considerations, coordination between distribution and transmission system planning
2. **Rates and incentives** includes issues such as managed charging rates and protecting low income consumers, but not on injecting-distributed energy resource (DER) compensation such as net energy metering
3. **Targeted and integrated deployment** includes issues of program design and delivery
4. **Grid connection** includes topics of interconnection, accommodating new and increased loads, and grid-readiness standards
5. **Distribution operations** includes topics of distribution level visibility and control of electrified loads, including coordination with aggregators
6. **Data access and sharing** includes issues of how data and information can be shared within and outside of the utility, and standardized methods for sharing and communicating information such as distribution-level data, planning assumptions, and customer information.

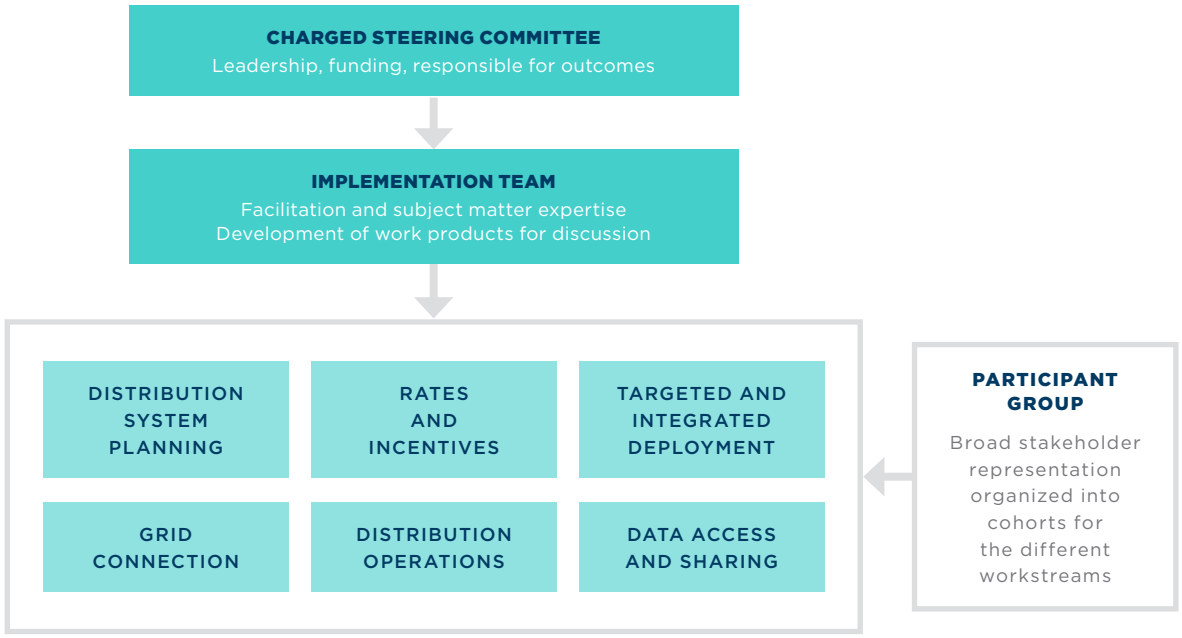
INITIATIVE WORKSTREAMS



Given that the issue of data access and sharing is relevant to all workstreams, this workstream has been conceptualized as a cross-cutting workstream in addition to it being its own individual workstream.

The structure of CHARGED is shown below. GridLab, RMI and Advanced Energy United constitute the Steering Committee, which is responsible for overall leadership. The Steering Committee leverages facilitation and consulting expertise through the Implementation Team to ensure that high-quality documents are developed to inform stakeholder discussions and to provide critical facilitation to support productive group discussions. The Participant Group includes the many organizations that bring diverse and valuable perspectives to inform dynamic discussions on electrification.

CHARGED STRUCTURE



CHARGED is structured to generate technical solutions that can be broadly implemented by creating an environment that facilitates effective and efficient engagement and collaboration.

ORGANIZATION OF REPORT

This report summarizes the work of CHARGED to date, including the development of a Briefing Document and the outcomes from the Inaugural Convening, held on April 10-12, 2024, in Boulder Colorado. Following this Introduction, the report presents a summary of the Inaugural Convening. Subsequently, each of the five workstreams—planning, rates, deployment, grid connection, operations—have their own chapters. Each of the workstream chapters is organized into five sections:

- **Overview**
- **Challenges and emerging practices**
- **Least-regrets solutions**
- **Longer-term solutions**
- **Data requirements**
- **Reading list**

These chapters include material from both the Briefing Document and reflections from Participants from the convening discussions. By organizing the chapters this way, the reader will see the specific information Participants received before attending the convening, which shaped how the facilitated discussions were structured, and how the discussions evolved at the convening. The intention with providing this detail is so that the reader can have some visibility into both the processes and outcomes of the convening.

A final chapter on data access and sharing is included which is based exclusively on the Briefing Document; reflections on data access and sharing were embedded in the "Data requirements" sections of the preceding chapters.

KEY TERMS

For the purposes of this document, here are some key terms. This is not meant to be an exhaustive list. Additional terms that are specific to a particular workstream are defined in their chapter.

DSM programs	Refers to efforts to reduce the overall consumption of energy (energy efficiency) or the shape of energy consumption (such as load shifting, shed-based demand response) of a customer; it can reflect past program designs or innovative and different future program designs.
Grid connection	We use this term to discuss the connection of both load or generation; some of these may involve different utility processes of interconnection, but grid connection refers to the connection of load/generation in a holistic sense.
Least-regrets solutions	These are intended to be practices that most or all jurisdictions can implement in the near term (e.g., within the next three years) with minimal downside, regardless of policy focus, resources, demand characteristics, or regulatory culture. Solutions can be any format, including technical, analytical and process oriented. During the meeting we hope to identify a subset of these least-regrets solutions that participants can largely agree on.
Managed charging	Refers to any intervention that aims to shape electric vehicle charging, and can include price based control or automated load management

CONVENING SUMMARY

CONVENING OVERVIEW

The first year of CHARGED focused on preparing for and hosting the Inaugural Convening, held in Boulder, Colorado over three days (April 10-12, 2024). Convening participants are listed in the front matter of this document. In summary there were roughly 60 participants from across the industry that included several utilities, advanced energy solutions providers, OEMs, public interest groups and regulatory perspective experts.

The participants were divided across the five workstreams—planning, rates, deployment, grid connection, operations— based on their expertise and preferences. As noted, to ensure a holistic treatment of data access and sharing, the data workstream was embedded in all other workstreams. In advance of the convening, the Steering Committee and Implementation team developed and shared a 50-page Briefing Document that included challenges, proposed solutions, and reading materials for each of the workstreams. The purpose of the Briefing Document was to facilitate more productive discussions, rather than starting "from scratch" at the convening.

The proposed solutions were structured around two categories—least-regrets and longer-term solutions.

Least-regrets solutions are intended to be practices that most or all jurisdictions can implement in the near term (e.g., within the next three years) with minimal downside, regardless of policy and regulatory environment. Solutions can be any format, including technical, analytical and process oriented.

Longer-term solutions are those that will require exploration and discussion beyond the convening—possibly through a combination of analysis, ideation, or demonstration.

The purpose of the convening was to (1) prioritize and generate agreement on the least-regrets solutions, including what these may look like in practice; and (2) identify relevant longer-term solutions that could tackle more challenging questions, including the contours of a project for further exploration.

In addition to these "hard" goals, the convening was also designed to build rapport among Participants, create momentum to implement prioritized solutions, and generate enthusiasm to engage in future CHARGED activities.

BRIEFING DOCUMENT

The Briefing Document was intended to propose a set of themes, challenges and solutions to facilitate the Convening discussions to be more focused and solution oriented. The content was not intended to be "final"—rather, the assumption was that the convening would provide the venue for collaborative discussions and debate. The Briefing Document was not intended to be comprehensive—it was expected and encouraged that Participants would bring their own experiences and perspectives, and proposed solutions, which may or may not align with what was written in the Briefing Document.

The Briefing Document was developed with input across the Steering Committee, Implementation Team, and a few Participants.

SUMMARY OF CONVENING DISCUSSIONS

Overall process

Each workstream group (planning, rates, deployment, grid connection, operations) had their own dedicated Implementation Team consisting of subject matter experts and facilitators. Steering Committee members were distributed across the groups.

While each group was tasked with the ultimate goals of identifying and prioritizing both least-regrets and longer-term solutions, the paths that each group took were customized for the content and facilitator style. Facilitators were empowered to adjust their approaches as needed based on the progression of the discussions and Participant feedback.

For this reason, each workstream chapter is unique. Nevertheless, each workstream identified and discussed the core themes of challenges, least-regrets solutions and longer-term solutions. The summary below focuses on the outcomes across these themes.

Challenges, least-regrets solutions and longer-term solutions

Across the individual workstream groups, Convening participants were able to assess and debate the challenges presented in the Briefing Document. While some groups validated these challenges with minimal changes, one group (rates and incentives) developed additional challenges and reframed these into a new set of objectives to facilitate further discussion. Another group (operations) discussed the challenges in more expansive ways, bringing in the "human" dimension more centrally. The table below provides a brief summary of the top challenges that each group identified.

WORKSTREAM	TOP CHALLENGES
Distribution system planning	• Load forecasting » Transitioning from top-down to bottom-up forecasts » Overcoming organizational silos • Planning models » Tools/data and availability of data inputs/tools » Agreement on scenarios and investment levels • Strategic proactive investment » Granular system info and locational value to inform investments » Prudency, priority, cost recovery, rate increase aversion
Rates and incentives	• The group developed a more comprehensive set of challenges than were provided in the Briefing Document but but did not rank the challenges • The group finalized five statements articulating objectives that the group wanted to solve • These statements tackled goals of equitable cost allocation and promoting load shapes that are cost-effective to serve now and in the future
Targeted and integrated deployment	• General program design » Lack of program data tracking which can inform better program design » Insufficient customer service and education • Targeting » Opportunity for greater coordination across utility departments (especially with respect to targeting for grid constraints) » Lack of customer equipment and grid readiness (e.g. min efficiency standards to avoid congestion, wiring upgrades) • Integrated deployment » Opportunity for utilities to improve g co-deployment (e.g. electrification with efficiency and/or load control, time-varying rates) » Fleet customers are a special load growth case and new program methods are required to onboard them
Grid connection	• Did not rank the challenges but generally agreed with the framing of the challenges and discussed them in more detail • Themes of the challenges discussed in more detail included » Aligning load and generation interconnection » Load characteristics and load growth uncertainty / visibility » Problem solving versus regulatory compliance » Grid connection and distribution planning
Distribution operations	• While the group did not disagree with the challenges in the Briefing Document, they quickly expanded beyond them. » Business as usual is unsatisfactory and too expensive » Electrification cannot be solved by just building more wires (operations will need to evolve) » Operators can be overloaded with tasks/information » Economics of foundational investments are unclear » Customer experience must not be affected » Utilities are at different stages of technological evolution

Overall, Participants discussed and validated roughly 40 Least-Regrets Solutions (LRS) and developed 10 of these in more detail. Groups assessed the LRS proposed in the Briefing Document, modified as needed, combined similar LRS, added additional LRS to the list, and recategorized some LRS that were deemed to be more appropriate as longer-term solutions.

In general, most groups supported the LRS proposed in the Briefing Document and conducted ranking exercises to identify top LRS with two exceptions: The rates group had a different ranking approach in which they considered "project ideas" around both the LRS and longer-term solutions (LTS), while identifying that some of the LRS in the briefing document wouldn't be taken forwards at the Convening, but could still be useful material for future work. The operations group felt the proposed LRS may not be accessible to all utilities and reframed the LRS through discussions.

The table below lists the top ranked LRS from each group that were prioritized for deeper discussion.

WORKSTREAM	PRIORITIZED LEAST-REGRETS SOLUTIONS
Distribution system planning	• Exploring opportunities to improved forecasting and power flow modeling • Proactive upgrades with routine investments • Planning for operational flexibility
Rates and incentives	• Taken forward as a LRS (but not a project): Offering some form of opt-out TOU rates for all customers, with customer education/opt-in rates for commercial fleets • Taken forward in a project: Options for cost allocation frameworks for proactive investments and reviewing current bill/connection protections for low-income customers • Not taken forward in the convening discussions: Considering managed charging pilots (The rationale was that managed charging can be considered indirectly across all projects)
Targeted and integrated deployment	• Improved utility department coordination on processes, data sharing and cross-training • Co-deployment of electrification with EE and load management programs/rates • Establishing partnerships with industry organizations such as local and regional fleet associations
Grid connection	• Streamlined load connection processes that are more transparent and externally accessible • Static flexible interconnection, which uses load management strategies and technologies to reduce the overall impact of the resources on the system, reducing system upgrade costs and shortening connection times • Sizing calculations, which uses refined methods and tools for equipment sizing and connection study processes, along with enhanced data sharing
Distribution operations	• People: Bring the operators into the conversation, not just about operations but also into conversations on planning, deployment, connection, rates. • Plan: Develop an operations investment roadmap that identifies triggers for specific investments • Action: Prioritize foundational investments beneficial today but for future electrification growth (e.g., GIS systems). • Note, these went beyond what was proposed in the Briefing Document

All groups discussed the open questions and gaps that were described in the Briefing Document. In contrast to the least-regrets solutions, the potential number of longer-term solutions was voluminous. Each group was able to navigate the complex space of future challenges, and cumulatively identified more than 14 project outlines that could inform longer-term solutions (LTS).

WORKSTREAM	LONGER-TERM SOLUTION PROJECTS
Distribution system planning	• Public scenario planning explorer • Framework for proactive investment • Performance incentive mechanisms for proactive investment (which can be a companion to framework project)
Rates and incentives	• Advanced rate design proceedings to support electrification • Residential rates with differential control thresholds to support DER management ("Do More Save More") • Opt-Out load management rates • Subscription or demand charges for secondary voltage networks and line transformers
Targeted and integrated deployment	• Program Design 2.0 by leveraging existing program data • Integrated data platform
Grid connection	• Dynamic, flexible hybrid grid connection • Cost allocation / obligation to serve
Distribution operations	• Traditional versus flexible operations: "Is the juice worth the squeeze?" (comparing the benefits of flexible operations relative to traditional operations) • Identifying GIS best practices • Autonomous orchestration and developing ideal load curves

Data access and sharing

Data access was discussed more explicitly in some groups compared to others. Some, but not all, groups had "data coaching" sessions to discuss data access and sharing.

- **Distribution System Planning** – the topic of data requirements was a common theme, although the topic of sharing between utility departments was not discussed explicitly.
- **Rates and Incentives** – discussed data requirements in the context of each of their projects but did not have a coaching session, nor did the group discuss extensively the topic of data sharing and access.
- **Targeted and Integrated Deployment Strategies** – much of the discussion was centered on data, and specifically data sharing between different departments of the utility. The deployment group did not have a coaching session.
- **Grid Connection** – discussed data requirements throughout the discussions and included this as part of their thinking about LRS. The grid connection group had a coaching session on data. They discussed the different categories of data sharing (intra-utility, utility to external actor, and external actor to utility).
- **Distribution Operations** – discussed data extensively but focused less on data sharing and access between operations and other utility departments or external actors.

The topic of overcoming utility organizational/data silos evolved in a few groups, suggesting that it is a topic worthy of further consideration.

NEXT STEPS AND OPPORTUNITIES

In the next phase of CHARGED, we will focus on these four tasks:

1. Further refine the least-regrets solutions discussed and prioritized at the Convening
2. Tackle the longer-term challenges through further ideation and collaboration among Participants
3. Implement multiple least-regrets solutions at the state and utility level
4. Socialize CHARGED findings and ideas across the industry, including with additional public-facing materials from subsequent CHARGED activities.

Most importantly, CHARGED aims to accomplish these tasks through continued collaboration and partnership with CHARGED participants and other organizations—and will continually work to bring in more diverse and useful perspectives to the Participant cohort.

The Convening validated that collaborative multi-stakeholder discussions– when given the appropriate structure– can build alignment and make progress on critical solutions needed to advance electrification. Importantly, this progress can occur outside of the more adversarial environment of regulatory proceedings. While traditional regulatory processes remain important, the kind of collaboration that is the focus of CHARGED can complement those processes and accelerate decarbonization.

DISTRIBUTION PLANNING

OVERVIEW

Distribution planners face unprecedented challenges, but load growth and technological innovation also create opportunities. Distribution systems will likely need significant capacity expansion to reliably accommodate new loads and distributed generation, but the timing and magnitude of load growth is uncertain and will, to some extent, be driven by state and federal policy. Customer response to new rate designs and participation in flexible interconnection, utility programs for load management, non-wires procurement, and utility resource procurement may reduce the need for distribution capacity expansion. Distribution planning will play a pivotal role in managing uncertainty and balancing expansion, efficiency, and affordability.

Three areas of distribution planning are especially important for managing load growth and its uncertainty: (1) load and resource forecasting, (2) planning models, and (3) strategic, proactive investments. Data sharing is discussed in (1) and (2).

This chapter is organized into the following main sections:

- **Challenges and emerging practices**
- **Least-regrets solutions (LRS)**
- **Longer-term solutions (LTS)**
- **Data requirements**
- **Reading list**

The first three sections contain material from the Briefing Document, which attendees received prior to the convening, and summarizes the convening discussions of the planning group. The data requirements section synthesizes how data sharing was discussed by the planning group. The reading list section is background reading that was provided to participants in the Briefing Document.

For readers that may be new to distribution planning, we recommend pages 6-7 of GridLab's "Integrated Distribution Planning: a Path Forward"[3] and Utility Distribution Planning 101[4] by NREL and PNNL as primers on distribution planning.

3 gridlab.org/wp-content/uploads/2019/04/IDPWhitepaper_GridLab-1.pdf

4 Coddington (NREL) and Schneider (PNNL), 2020, Utility Distribution Planning 101, video link: youtube.com/watch?v=1NBCzWNWhWA and presentation link: eta-publications.lbl.gov/sites/default/files/5._coddington_and_schneider_utility_planning_101.pdf

CHALLENGES AND EMERGING PRACTICES – BRIEFING DOCUMENT

For ease of reading, we have identified practices and challenges with labels throughout this section.

Load and resource forecasting

- A growing number of utilities are undertaking longer-term, scenario-based distribution plans. ***(Practice)***
- Planning scenarios tend to focus on electrification, distributed generation / distributed storage (DG/DS) adoption, and changes in climate, with scenarios extending out 15 to 25 years. ***(Practice)***
- The table below shows examples of planning horizons and scenarios considered for a subset of utilities.

UTILITY	PLANNING HORIZON	SCENARIOS
Consumers Energy (MI)	5-year investment plan; scenarios out to 2050	• Decelerated transition • Continued momentum • Accelerated transition
DTE Electric (MI)	5-year investment plan; scenarios looking out over next 15 years	• High electrification • Increasing CAT storm • High DG/DS
Xcel Energy (MN)	5-year investment ("budget") plan; scenarios over 10 to 30 years	• Historical data used for projecting next 4 years • LoadSEER used for low/medium/high DER adoption over 30 years • DERs considered are customer electrified load, DG, DR, EE
National Grid (NY)	5-year investment plan; 15-year load and DER forecasts	• Heat pump scenarios • EV scenarios • DER scenarios • Climate scenarios
ComEd (IL)	5-year investment plan; scenarios out to 2050	• Reference load, moderate electrification, high electrification • Climate adaptation

- There are open questions about how utilities will use these plans: the medium- to longer-term captures electrification and other more structural changes, but these are often outside of distribution utilities' capital budgeting horizons and in some cases not systematically incorporated into distribution planning models. ***(Challenge)***
- In part, questions are tied to the uncertainty associated with long-term forecasts; if longer-term projections do not materialize, utilities may face cost disallowance or customers may be forced to pay for under-utilized assets. ***(Challenge)***
- Partnerships with vehicle manufacturers, fossil-based fleet managers (who are considering going electric), cities and other organizations may give visibility into what their forthcoming electric fleet behavior may be and inform potential load growth. This could be valuable, especially, for large loads such as commercial fleets. ***(Practice)***

- As an example, Eversource has created partnerships with OEMs to collect vehicle behavior data in anticipation of forthcoming electrification. To inform building electrification, they have partnered with a Town/City Building Permit and Development Authority to receive alerts based on building permitting. ***(Practice)***
- The crux of the forecasting challenge is that forecasts will be inherently wrong and will be more wrong (higher forecast errors) the farther out in time one goes, which means that there are increased risks to both utilities and ratepayers if utilities rely on longer-term forecasts to make investment decisions. ***(Challenge)***
- To help manage this risk, utilities need new approaches and tools that incorporate electrification-driven load growth, DG/DS adoption, and structural changes in net load profiles[5] into their longer-term planning forecasts, including: ***(Practice)***
  - » **System-wide –** adoption forecasting (EVs, heat pumps, distributed generation (DG)/ distributed solar (DS), with more locational and technology detail and greater use of non-traditional data (e.g., travel data, such as customer commute information) in forecasting;
  - » **Local –** disaggregation of adoption forecasts into time-differentiated, local (substation or feeder-level) load and net load profiles, and greater use of AMI data, where available, in forecasting.
- Many utility distribution planning forecasts already incorporate adoption forecasts and methods to generate distribution-level forecasts, sometimes involving disaggregation of system-wide or regional forecasts, and sometimes (in rare occasion) involving detailed bottom-up modeling.
- For example, Portland General Electric's approach (see additional references) combines a regression-based corporate forecast, bottom-up adjustments to local loads (e.g., due to expected load growth, planned additions, weather, EVs and other new sources of demand), and locational DER (DR, DG/DS, EVs) adoption and net load forecasts at a feeder level (using the AdopDER model).
- While there is likely more commonality in corporate forecasting methods, utilities appear to differ significantly in their approaches to local forecasting and integrating load management into local load forecasts.
- New software tools and datasets (e.g., LoadSEER, AdopDER, DGen, EVs2Scale2030, PowerClerk, ResStock, ComStock) have emerged that support scenario-based forecasts, include adoption forecasts with local translation, and in some cases are integrated into utility data management systems. ***(Practice)***
- Forecasting draws on data from other utility departments (e.g., AMI data, data on customer loads and rates, interconnection data, resource planning data); making this data available to forecasters may require coordination across utility departments as well as changes in utility data management architectures and software systems. ***(Challenge)***
- Xcel Energy's Integrated System Planning business unit is an example of changes in organization to support communication and coordination across utility departments.

5 Net load here refers to customer gross load minus behind-the-meter generation, including storage discharge.

Planning models

- To accurately reflect distribution investment needs, the power flow models that many utilities use to anticipate these needs may need enhancements, such as: ***(Challenge)***
  - » Multi-period (rather than single peak) analysis
  - » More spatial coverage (e.g., secondary distribution systems)
  - » Incorporation of DG/DPV impact on loading
  - » Incorporation of managed charging and other DSM programs and rate designs as a mitigation option
  - » Incorporation of smart inverter functions (e.g., volt/Var with Volt/Watt as a backstop)
  - » Integrations with other utility data platforms (AMI/SCADA historian, interconnection portal, forecasting software, DRMS/DERMS, etc.)
- These enhancements may be part of broader improvements to power flow models and other tools that, for instance, consider changes in weather-related parameters and planning criteria.
- Some utilities are beginning to incorporate DG/DS, DSM, and rate-driven changes in distribution loads—both current and future—in their modeling processes and capacity assessments.
- Examples are in the following table:

UTILITY	MODELING APPROACH	DESCRIPTION
Northern States Power Company	Planned net loading (PNL)	Method for estimating reliable solar-derived capacity
Southern California Edison	Dependable photovoltaic generation methodology	Method for estimating reliable solar-derived capacity
National Grid (MA)	Managed charging	Long-term (2050) forecasts include scenarios with unmanaged and managed charging
Central Hudson Gas & Electric	Geo-targeted DSM	Peak Perks Program controls central AC and pool pumps for load relief on capacity constrained circuits; expected load relief is incorporated into planning assessments

- However, it is not clear how utility processes and analytics should change to better incorporate DG/DS, DSM, and rates into distribution planning. ***(Challenge)***
- For instance, should the impact of DER and rates on loads be included by forecasting teams and provided to modelers as net loading forecasts, should modeling teams take "gross" load forecasts from forecast teams and make adjustments themselves, and how should forecasting, modeling, and programs departments interact? ***(Challenge)***
- Utilities, researchers, and software vendors are also beginning to consider larger changes to modeling tools, such as multi-period analysis (see utility presentations for NARUC training in Additional Reading). ***(Practice)***
- Like forecasting, making data from other utility departments available for modeling may also require changes in data management systems. ***(Challenge)***

- The results of planning models can also be useful for customers, aggregators, intervenors, and other stakeholders.
- Many utilities have developed approaches to making this information publicly available to stakeholders through hosting capacity maps, distribution planning proceedings, and other processes. ***(Practice)***
- Some utilities do not use power flow modeling to assess reliability violations, but instead rely on interval load data measured at key assets (e.g., substation, distribution transformer), and compare through spreadsheet analysis remaining capacity. For these utilities, the question may be whether they should transition to a power flow model and when.

Strategic proactive investment

- In areas with rapid load growth, utilities may need to make at least some investments in distribution equipment proactively to avoid equipment failure. ***(Challenge)***
- Proactive investments create challenges for regulatory approval and cost allocation. ***(Challenge)***
- The question of how to deal with proactive investments has been raised in several proceedings, but there is limited regulatory precedent.
- For instance, Northern States Power Company's Grid Reinforcement Program (2021 rate case) proposed "approximately $12 million in capital additions to help prepare [its] system for increased load growth from EVs and beneficial electrification by replacing and upgrading service-level transformers."
- This proposal was deemed to be too speculative and was rejected by the PUC; Northern States Power Company is proposing significant proactive investments in its 5-year budget and is seeking input from stakeholders on how to approach proactive investments and how to integrate them into investment prioritization.
- Additionally, utilities may be able to make some strategic investments at lower cost by aligning them with other processes (e.g., storm recovery, normal maintenance, hardening activities) and by considering upsizing for capacity or voltage class when assets are replaced in these processes.
  - On normal maintenance opportunities: upsizing may happen naturally in jurisdictions where equipment standards have been updated since the failed equipment was deployed such as New York or California IOUs.
  - On hardening activities: multiple utilities have folded upsizing and grid modernization into their hardening programs, such as Southern California Edison, DTE, and Black Hills Energy
  - On new construction: designing new infrastructure for future voltage conversion (e.g., from 12kV to 25kV class equipment) can significantly reduce future upgrade costs where voltage conversions are part of the long-term plan

CHALLENGES AND EMERGING PRACTICES – CONVENING DISCUSSION

Outcomes and Scope

As an opening exercise, the group enumerated outcomes from distribution planning practices that would better enable accelerated electrification. Outcomes included:

- Better forecasts, methods, and a better system of aligned scenarios
- Better processes for linking planning analysis and investment
- Streamlined processes
- Lower cost electrification
- Fearless development and consumer adoption of electrification technologies
- Technologies and strategies to avoid costly upgrades
- Clarity on to how to address system capacity constraints
- Extending two-year planning confidence to five years
- Data-driven feedback loops to inform decision-making
- A fully informed regulatory body that can make confident decisions
- Frameworks, guidance, and metrics for guiding proactive investments

To refine the scope, the group identified the types of loads that could be electrified, for consideration throughout the convening. By sector, these included:

- **Transportation:** EVs, fleets, ports, trains and long-haul freight, heavy duty transportation, air transport, ferries, and drayage
- **Industry:** construction, food & beverage, farming and tractoring, data centers, indoor agriculture, and process heating
- **Energy:** hydrogen production
- **Buildings:** water and space heating, new development/redevelopment, and cooking

Prioritization of challenges and emerging practices

There was general agreement on the three challenge areas described in the Briefing Document (forecasting, planning models, and strategic proactive investment). For each challenge area (shown in the tables below), the group highlighted a subset of emerging practices and challenges from the Briefing Document and identified the top two or three challenges and practices that would be useful to explore further. These prioritized challenges and practices were used as a foundation for the discussion on least-regrets solutions (LRS) and longer-term solutions (LTS).

Load forecasting – prioritization of challenges and practices

	HIGHLIGHTED FROM THE BRIEFING DOCUMENT	GROUP PRIORITIZED
Practices	• Long-term scenario-based planning • Forecasts based on adoption behavior • Incorporation of new software tools • Partnerships to inform forecasts and scenarios	• Incorporation of new planning software tools • Forecasts based on DER adoption/deployment and customer behavior • Customer and community engagement
Challenges	• Incorporating scenarios and uncertainty (loads, weather, climate) into plans • Transitioning from top-down to bottom-up forecasts • Overcoming organizational/data silos (AMI, interconnection, DSM programs)	• Transitioning from top-down to bottom-up forecasts • Overcoming organizational silos

Planning models – prioritization of challenges and practices

	HIGHLIGHTED FROM THE BRIEFING DOCUMENT	GROUP PRIORITIZED
Practices	• Time series (rather than single peak) analysis • Modeling gross (native) and net load • Publicly sharing model results and plans	• Decoupling gross and net load
Challenges	• Accounting for the impact of load modifiers (DER, DSM, managed charging, rates) • Grid edge (secondary) modeling • Modeling smart inverter capabilities • Opaqueness of modeling outputs • Value of potential DER investment (not just behind the meter) • Finding the right level of aggregation	• Tools/data and availability of data inputs/tools • Agreement on scenarios and investment levels

Strategic proactive investment – prioritization of challenges and practices

	HIGHLIGHTED FROM THE BRIEFING DOCUMENT	GROUP PRIORITIZED
Practices	• Upsizing/conversion as part of "routine" investments • Load diversity assumptions and design standards • Funding for future upgrades	• DERs that support the system (as solutions to be incorporated into decision-making) • Scenarios/portfolio presentation
Challenges	• Timing: electrification enablement vs. prudency • Location: balancing utilization, affordability, and equity • No frameworks/metrics to guide decisions • Competing priorities	• Granular system info and locational value to inform investments • Prudency, priority, cost recovery, rate increase aversion

LEAST-REGRETS SOLUTIONS – BRIEFING DOCUMENT

Recap of core challenges

- **Forecasting:** accurately forecasting the timing and location of load growth and changes in load under large uncertainty, as well as managing that uncertainty.
- **Planning models:** accurately determining the need for new distribution investments and including load management and reductions in planning models.
- **Strategic proactive investment:** balancing proactive investment with concerns about utilization, affordability, and equity.

Potential least-regrets solutions

Least-regrets solutions for distribution planning are intended to (a) provide a strong foundation for managing load growth, even if utilities are not yet experiencing it, and (b) be relevant for most or all distribution utilities, regardless of jurisdiction or location.

Potential least-regrets planning solutions

(Entities responsible for implementation are in parentheses)

	LEAST-REGRETS SOLUTION
1	Considering managed charging, demand response, and other DSM programs in investment planning (utilities)
2	Better understanding load growth for large customers, especially fleets (utilities)
3	Exploring opportunities to improve forecasting and power flow models (vendors, utilities)
4	Using AMI data, where available, in load forecasting and planning (utilities)
5	Leveraging other processes (e.g., asset replacement, outage restoration) to make strategic investments and reduce upgrade costs (utilities)
6	Incorporating generation/load parameters into planning models (vendors, utilities)
7	Utilities not using power flow models should identify threshold / operating parameters for when they start using power flow modeling (utilities)
8	Updating primary and secondary voltage design and sizing practices for load additions (utilities)

LEAST REGRETS SOLUTIONS – CONVENING DISCUSSION

Overall discussion

The group added two LRS to the list of the first seven planning LRS in the Briefing Document:

- "Planning for operational flexibility" which means the opportunity to more effectively integrate an assessment of the operational capabilities and investments (grid modernization) into the planning process.
- "Resilience and equity assessments" which means incorporating methodologies and metrics to assess how distribution system plans support customer equity and resilience, including proactive investments that support equity, justice, and resilience.

The sixth LRS, which was insufficiently clear, was omitted from the listing of LRS and was not discussed.

Prioritization

For each LRS, including these two that were added, the group voted on whether it is a high priority and whether it is truly a least regrets strategy or is still an open question. The table below shows the results of the group's prioritization.

	NUMBER OF VOTES			
LEAST REGRET SOLUTION	**IS HIGH PRIORITY**	**NOT HIGH PRIORITY**	**IS LRS**	**TOO OPEN**
1. DSM, managed charging in investment planning	6	1	4	5
2. Insight into customer load growth	8	1	7	0
3. Improved forecasting, power flow modeling	7	0	8	0
4. AMI data use in forecasting/ planning	7	0	3	3
5. Proactive upgrades with routine investments	8	0	6	1
7. Adoption of power flow modeling	2	4	2	0
8. Updated design standards	2	0	1	2
(New LRS) Planning for operational flexibility	6	0	4	0
(New LRS) Resilience and equity assessments	8	1	1	5

Based on voting, the group decided to consider three LRS in more detail:

- 3. Improved forecasting (including customer engagement), power flow modeling
- 5. Proactive upgrades with routine investments
- 8. Planning for operational flexibility

The group determined that there was overlap among LRS 2, 3, and 4. The group felt that the new LRS on resilience and equity assessment was a high priority but not a LRS.

Detailed discussion on prioritized least-regrets solutions

The discussion on LRS was structured around three questions: (1) What is different in the world when the LRS is implemented? (2) Why is the LRS not happening today? What are points of leverage to make the LRS happen? The table below shows the group's response to these questions for each prioritized LRS.

	WHAT IS DIFFERENT IN THE WORLD WHEN THE LRS IS IMPLEMENTED?	WHY IS THE LRS NOT HAPPENING TODAY?	WHAT ARE POINTS OF LEVERAGE TO MAKE THE LRS HAPPEN?
LRS 3: Improved forecasting, power flow modeling	• High-confidence, long-term capital investment planning • Ability to optimize across a range of technologies	• Lack of perceived need • Challenge of changing process and data requirements • Challenges of decision-making under uncertainty	• Regulatory shifts (e.g., software capitalization) • Government (non-regulatory) interfaces with planning for refining policy • Scenario planning requirements (standards, uncertainty management)
LRS 5: Proactive upgrades with routine investments	• Grid more prepared for electrification and is not a constraint to electrification in terms of timing of investments	• Regulatory approval • Lack of organizational awareness (planning, asset management, supply chain, emergency response) • Capital availability	• Tools to help regulators understand opportunities • Within utilities, coordination among planning, engineering, operations, and supply chain management • Updated methods and design standards • IT for developing analysis and management tools
New LRS: Planning for operational flexibility	• Utility planning and operations collaborate and talk • Public support is present for investments in R&D and emerging technologies • R&D is integrated into distribution and gridmod strategy	• Siloed organizations • Lack of workforce and talent • Technologies are too nascent	• Foundational guidance to regulators and policymakers • National funding to enhance workforce • Educations for policymakers • Strategic direction within utilities to align departments • Clear value proposition to and from multiple stakeholders

LONGER-TERM SOLUTIONS – BRIEFING DOCUMENT

Open questions and longer-term solutions

- Although distribution planning is rapidly changing, there are still many open questions that will need to be resolved over the next decade.
- Open questions include:

Long-term, scenario-based planning

  - » What should a long-term distribution plan look like (scenarios, level of detail)? How can scenarios be best managed and prioritized?
  - » What are the risks of overbuilding and underbuilding distribution infrastructure? Can they be meaningfully quantified?
  - » How can utilities bridge between long-term, scenario-based planning and capital budgeting? What purposes should utilities use long-term plans for?

Forecasting

  - » Will a virtuous cycle with evolving utility needs and forecasting software improvements resolve forecasting challenges, or is there still a step change needed?
  - » What new partnerships and processes should utilities establish in order to inform load

growth from electrification, such as from fleets?

» If and as utilities increasingly rely on third-party tools, and/or outsource forecasting services, how and will utilities have sufficient visibility into these processes, and how will these third parties access necessary utility data/conditions that span utility silos?

Planning models

» What changes to distribution planning models are needed to better anticipate electrification-related load growth, while addressing rising levels of DG/DS and changes in climate?

» How should existing and future DSM (managed charging, DSM programs, flexible interconnection) be captured in load forecasting and power flow models? What changes in organization (e.g., responsibilities, coordination among departments) and analytics are required to do so?

» How can small utilities that currently do not use power flow models adapt their analytics to an evolving future? At what point and under what conditions will they need to adopt power flow models?

Strategic and proactive investment

» What is a reasonable framework for strategic, proactive investment? Does anything about the existing regulatory framework/process need to change?

» What are the criteria for proactive investments and how can prudency be demonstrated, and what tools should be used to adopt risk-based planning for proactive investments?

Data management and sharing

» Is there an optimal model for internal data management and sharing systems for utilities, or will each utility require a tailored architecture?

» What planning data do stakeholders need?

Collaborative planning processes

» How can outside stakeholders and 3rd parties engage productively in planning processes? How should they interface with utilities and respective utility departments (e.g., planning, customer programs)?

» What information can they bring to facilitate planning that effectively accounts for DSM opportunities via DERs and innovative technologies/approaches?

Short-term solutions

» What quick, short-term solutions (e.g., mobile batteries, transformer reserves) should utilities have in their pockets to deal with rapid load growth? What is the role of planning in helping to identify and target these solutions?

LONGER-TERM SOLUTIONS – CONVENING DISCUSSION

Overall discussion and problem statements

The facilitation team proposed three LTS areas for the group's consideration: scenario planning, modeling DSM in planning, and strategic proactive investment. The group confirmed that these were the right areas for LTS discussion and added a fourth area: collaborative planning processes. The LTS discussion began with problem statements for each area (which were to include a statement of the problem, for whom, and why the problem was important), then developed potential projects to address a subset of these problems.

Scenario planning problem statements

- PUCs/utilities do not have standard methods for scenario planning and how it is used.
- Who is responsible for using planning scenarios that may not come to fruition?
- Who is responsible for determining which scenario to plan for?
- Planners often only consider a single, deterministic future when developing investment plans, uncertainty is ignored.
- Risk analysis of over/under building is not well developed, and therefore scenarios are not usable or useful.
- Utilities lack solutions to identify least cost upgrade scenarios, making scenarios not useful.
- Scenarios do not lead to capital plans, so longer term scenarios are paper exercises.
- Utilities do not have the tools and data quality to do scenario planning.
- Planners have trouble choosing scenario parameters before they know how these scenarios will play out; they currently cannot conduct iterative scenario development because of the once-through modeling tools.
- Utilities plan to known loads in a 1-2 year timeframe, leading to inefficient and expensive incremental investment and foregoing comprehensive or cheaper alternative solutions.
- Is it possible to create a scenario modeling tool that stakeholders will use and is helpful?
- Utilities do not have a clear path towards developing more bottom-up forecasts with end-use/DER breakdown that can be used in planning tools.

Modeling DSM in planning problem statements

- DSM is challenging to trust in times of need.
- Operators do not trust that DSM will deliver, so planners can't/won't account for them sufficiently.
- Modelers cannot forecast the impact of DERs/DSM under different time, weather, customer type conditions because the evaluation data from pilots is not detailed enough and lacks a standard format.
- Planners typically exclude the load modifying impacts of DSM in load forecasts, maybe leading to an overstatement of load growth.
- Utilities lack standard methods and data for including DSM in planning.
- Planners at utilities cannot rely on passive demand response programs because they are probability factor based.

- Customers do not remember complex rate structures making DSM not achieve its full potential.

Strategic proactive investment problem statements

- How to design strategic and proactive investments across venues? Utilities are hesitant to make proactive investments in anticipation of load growth because of disallowance concerns.
- Benefit-cost analyses (BCAs) are not adequately robust; with adequate BCA, utilities can show that DER and proactive grid investments are not counter to keeping utility healthy and able to attract capital.
- Unclear benefit-cost assignments and associated rate increases make strategic proactive investment untenable to regulators; value timescale too short.
- Capital availability via IOU corporate investment strategy may be insufficient to support proactive investment.
- Regulations requiring "used and useful" lead to utility bias toward underbuild.
- How can regulatory lag be overcome?
- How can DER development be fit into "least" cost all resource planning?
- Utilities lack knowledge of future transformer/line costs considering supply chain limitations.

Collaborative planning process problem statements

- Stakeholders are often excluded from the distribution investment planning process, leading to skepticism/friction.
- Engagement with key customers or a subset of customers to assess rate of deployment can be challenging.
- Adversarial regulatory, political, and regulatory relationships prohibit the trust building that is required to truly integrate planning across stakeholders.
- Utilities' customer teams do not have a collaborative framework or data insights to drive collaborative planning.
- Working across multiple jurisdictions (community, state, region) can present inter-jurisdictional challenges.
- There is a lack of coordinated planning to determine investment strategies to support electrification.
- What's the incentive to collaborate when you litigate?

Proposed projects to address problems

Each member of the group was asked to create a proposed project with a project pitch. Pitches were then voted on by participants, to determine which projects would advance to the design phase. Proposed projects addressed three questions:

- What problem statement does the project address?
- What is the project?
- Why is it important?

PROJECT NO.	PROBLEM	PROJECT DESCRIPTION	WHY IS THIS IMPORTANT?	VOTES
1	**Stakeholders want more detail from models and data to participate in the planning process**	Public interface to forecasting model (w/ DER adoption) for interactive scenario exploration using real data	Creates trust and shared understanding about implications of different scenarios	5
2	**Unclear incentives for proactive investment**	Develop performance-based incentive mechanism for proactive investments that can be used in multiple jurisdictions	Sets transparent incentives for utilities	Unknown, but advanced to the next round
3	**No utility/reg framework for proactive investment**	Develop framework/metrics that work in multiple jurisdictions	Overcomes utility hesitancy, ensures cost recovery	2
4	**No utility/reg framework for proactive investment**	Utilities and regulators and stakeholders agree to an electrification least-regrets proactive investment framework • Prioritize highest customer value for cost • Focused on long term needs forecasts • Proactive investments get allocated of funding in multi-year rate plan • Priorities can change	Overcomes utility hesitancy, ensures cost recovery	4
5	**No utility/reg framework for proactive investment**	Community energy planning • Choose community and involve government institutions, major industry, business, fleets, community groups, disadvantaged communities • ID load growth + location • Survey propensity and willingness to participate in DSM programs • Design geo-targeted DSM • Quantify grid needs/cost (possibly finance) • Identify collaborative benefits, design replicable process, and quantify benefits	Overcomes utility hesitancy, ensures cost recovery	4
6	**Distribution planners do not trust DSM to reliably address local system capacity constraints**	Buckets of pilots or demos to define what is necessary to integrate various DSM types into planning	Distribution planners will have more confidence in DSM resources	3
7	**Challenges with scenarios in distribution planning**	Backtesting utility scenarios with munis, DER developers to better calibrate future scenarios	Not specified	0
8	**Regulators and utilities have different levels of understanding (and sophistication) in implementing integrated distribution system planning processes**	Provide a website that lays out the IDSP process, i.e., the separate components and how they are interrelated and link to best practices; this includes roles and responsibilities of the utilities and supporting analytical processes	There is too much time spent educating regulators, policymakers, and utilities	0 *(note: DOE is already doing this)*

The group then selected three projects to scope in more depth. The group combined projects 3-5 into one proposal and selected this proposal and projects 1 and 2 as the three projects to scope in more detail.

Project 1: Public scenario planning explorer

Problem statement: Variation in forecasting scenarios for distribution system planning can be hard to internalize and guide decision-making.

What is the project? Visual tool with "dials" where users can vary different forecast inputs in distribution plans and re-render distribution capacity investment requirements and look at metrics that they care about (e.g., community benefits, rate impacts, DER penetration). The tool could also have several base scenarios to support conversation among utilities, regulators, and stakeholders, for instance on issues of scale and how behavioral assumptions influence outcomes. Development of the tool would need to consider what is common for all jurisdictions versus extensions that are more jurisdiction specific, and would need to include stakeholders in the development process to ensure that it can be useful to users. Utilities and regulators would need to invest in education and training for the tool to be useful. In discussion, the group raised questions about how to balance user flexibility and computational time and complexity in the design of such a tool.

Why is it important? Facilitates understanding of locational value, capacity needs, disaster planning, and anomalous/novel DER behaviors.

Key partners: Utilities, regulators, stakeholders (e.g., customer advocates, large customers, community groups and representatives, NGOs), developers, and policymakers.

Project 2: Incentive mechanism for proactive investment

Problem statement: Utilities have unclear incentives for proactive investment.

What is the project? Develop a performance-based incentive mechanism for proactive investments that can be used in multiple jurisdictions and tied to measures of asset utilization and performance with respect to electrification outcomes. The mechanism could be tied to a specific set of investments or a bounded portfolio of projects specifically for enabling electrification, and could have thresholds for incentives that allow utilities to scale back efforts without incurring too large of a penalty. The upside could be structured as shared savings and the downside as a return on equity haircut on the specific capital investments. This kind of incentive could provide a means to build trust between utilities and regulators and stakeholders, establishing a forum for learning and tracking the outcomes of early strategic proactive investments. In discussion, the group raised questions about the need for and design of incentive mechanisms, and whether this project might be able to be bundled into the third project (framework for proactive investment).

Why is it important? Sets transparent incentives for utilities, overcomes hesitancy to do strategic investment, and supports utility and regulator learning about how to make proactive investment decisions.

Key partners: Utility, regulators, large customers, consumer advocates, environmental advocates, state agencies.

Project 3 (combined projects 3-5): Framework for proactive investment

Problem statement: Utilities lack regulatory frameworks for proactive investment.

What is the project? Develop a regulatory framework, in a collaborative way (not docketed), for proactive investment that can work in multiple jurisdictions. The framework would provide principles and methods that could be incorporated into rules developed in a more formal proceeding. Regulator involvement from the start would be critical for this effort to be meaningful. The framework would need to consider what is core across states versus what might be state specific. Coordinated language might be helpful to highlight the collective national need to have this conversation about proactive distribution investments. The project could also provide an assessment of early frameworks in other states (e.g., Colorado, New York) and the extent to which these could be transferable to other states.

Why is it important? Provides guidance and best practice for the timing and appropriate levels of investment, overcomes utility hesitancy, and ensures cost recovery.

Key partners: Working group with industry, utility, policymakers, advocacy groups, community representations

DATA REQUIREMENTS

The group did not have an explicit conversation on data requirements, but data issues cut across all the planning group sessions. In challenges and emerging practices, the group identified both data availability generally as a core challenge, and the lack of availability of locational value data as a challenge in making investment decisions. In LRS discussions, the group identified sources of data that were least regrets to integrate into distribution system plans, including AMI and other field sensor data. In LTS, the group identified a specific data tool (project 1, the public scenario viewer) that would support stakeholders to have more data transparency in distribution system planning processes. Both the framework for strategic proactive investment (project 3) and the performance incentive (project 2) would rely on both availability of granular distribution system data to assess where investments can have the greatest impact and track progress.

READLING LIST

Pre-workshop suggested reading

Note, the "pp." refers to the page numbers as indicated in print on the document, while the PDF pp. refers to the page number as it appears at the top of the PDF viewer tool.

- Jouni Peppanen, Electric Power Research Institute, 2023 presentation to ESIG building electrification task force, *Evolving Distribution Reliability along with Building Electrification*, suggest reviewing all 9 pages of the presentation presentation (With author permission, this document was shared with Participants)
- ESIG, 2024, *Charging Ahead: Grid Planning for Vehicle Electrification*, esig.energy/grid-planning-for-vehicle-electrification
  - » Forecasting EV Futures, pp. 15-19 (PDF pp. 28-32)
  - » Characterizing Locational and Temporal EV Impacts, pp. 20-27 (PDF pp. 33-40)
- Consumers Energy, *Electric Distribution Infrastructure Investment Plan* (2024-2028), September 27, 2023, consumersenergy.com/-/media/CE/Documents/company/electric-generation/ediip-report.pdf, pp. 23-26 (PDF pp. 24-27)

- Northern States Power Company, 2023, *Integrated Distribution Plan 2024-2033*, xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/202311-200132-09.pdf, Planning tools, PDF pp. 59-66
- Itron, *Central Hudson Gas & Electric Peak Perks Targeted Demand Management Program*, pp. 1-2 (This document is no longer available on Itron's website; please contact us for a copy)

Additional references

- NARUC, 2022, *How utilities plan distribution systems*, presentations by Lavelle Freeman and Juan Martinez, Eversource; Elton Prifti, National Grid; Kim Cullen, Avangrid; and Jody Londo, Xcel Energy, pubs.naruc.org/pub/47B689BC-1866-DAAC-99FB-82CCB3336C2E
- Portland General Electric, *2022 Distribution System Plan*
  - » Chapter 3, Load and DER Forecasting, assets.ctfassets.net/416ywc1laqmd/46I2n65SyTv3TUMMdq1l55/a993aebb7b7a84ebd3209d798454a33a/DSP_Part_2_-_Chapter03.pdf
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- Kevala, 2023, *Load forecasting- training for states on distribution system and distributed energy resources planning*, eta-publications.lbl.gov/sites/default/files/giraldez_20231129.pdf
- Keen et al., 2022, National Renewable Energy Laboratory, *Distribution capacity expansion planning: current practice, opportunities, and decision support*, Report TP-6A40-83892, nrel.gov/docs/fy23osti/83892.pdf

RATES AND INCENTIVES

OVERVIEW

There are multiple perspectives on the relationship between rates/incentives and electrification. These perspectives bring with them a range of objectives, tradeoffs, and socioeconomic considerations for how rates and incentives can best enable electrification. Utilities may use rate designs and incentives to encourage adoption of electric vehicles (EVs) and electric heating equipment. Rates and managed charging may also be an effective way to reduce bulk system and distribution infrastructure needs due to electrification. In some cases, rate designs may support both of these objectives—low off-peak rates, for example. In other cases like high demand charges, they may not.

Rate design for electrification may involve other tradeoffs as well. Rates that incentivize customers to avoid distribution peaks may lower total distribution costs but could shift fixed costs onto others, who may be low-income customers. Lower rates that encourage electrification could encourage inefficient timing and location of load growth, which could raise rates and shift costs onto lower income customers. Cost shifts can also occur if more engaged utility customers take advantage of opt-in rates designed for electrification or if bill protections are not implemented for more advanced, dynamic default (opt-out) rates. These potential tradeoffs mean that, increasingly, balancing different objectives—economic efficiency, equity, and policy goals—in rates will require careful design. This balance may differ across jurisdictions due to state and local differences in policy objectives, demographics, loads, resources, utility industry structure, and regulatory culture.

Thus far, most electrification-related rates have been relatively simple time-of-use (TOU) rates for EV charging, often paired with demand charges for commercial customers. Perspectives continue to differ on whether electrification rates should be kept close to marginal cost to encourage electrification or whether they should fully recover a fair share of embedded costs with an eye towards equity and affordability. Only a few utilities have locationally-differentiated rates that align incentives for shifting distribution demand with the timing of distribution capacity constraints, and those are mostly in early pilot stages. More utilities (but still not very many) have, or have piloted, rate designs paired with managed charging. The effectiveness, implications and customer adoption for different rate designs and managed charging programs still need to be better understood for different vehicle and customer combinations.

Rate designs for electrification also need to be considered in the broader context of distributed generation (DG)/distributed solar (DS) and utility programs. There may be efficiencies in integrating rate designs across technologies for EVs and DG/DS, for instance, to provide a consistent set of incentives for customers regardless of the kinds of generation, storage, and flexible loads they install behind the meter. Customers may also be willing to enroll in DSM programs in exchange for cheaper rates (or enroll in rates in exchange for rebates), though most utilities have yet to explore these kinds of synergies on a larger scale. We explore this issue, also, in the Targeted and Integrated Deployment Strategies chapter.

Many rate design questions are questions about cost allocation rather than rates per se. For example, if higher income neighborhoods in a utility service area are adopting EVs and lower income neighborhoods are not, should lower-income customers pay for the cost of new service transformers to support EV growth? Similarly, many of the fairness questions around proactive investments are cost allocation questions.

This chapter is organized into the following main sections:

- **Challenges and emerging practices**
- **Least-regrets solutions (LRS)**
- **Longer-term solutions (LTS)**
- **Project ideas**
- **Reading list**

The first three sections contain material from the Briefing Document, which attendees received prior to the convening, and summarizes the convening discussions of the rates and incentives group. In this chapter, data requirements are discussed within the context of each project idea. The reading list section is background reading that was provided to participants in the Briefing Document.

OVERALL APPROACH

The rates and incentives group took a different approach than the other groups. The rates and incentives group began by reviewing the challenges identified in the Briefing Document and developed these into a new comprehensive suite of challenges for consideration. The group then developed a set of objectives based on the challenges to help with project scoping and selection. Rather than consider LRS and LTS separately, the group developed project ideas that incorporate elements of LRS and LTS and tested these project ideas against the objectives. The four projects that the group shortlisted and focused on are described in the "Project ideas - Convening discussion" section.

CHALLENGES AND EMERGING PRACTICES – BRIEFING DOCUMENT

For ease of reading, we have identified practices and challenges with labels throughout this section.

- To date, pilots and implementation of new rates and incentives related to electrification have focused on EVs rather than heating loads; this is understandable given that EV adoption has been more rapid than heat pump adoption. ***(Practice)***
- Many utilities have, or are piloting, dedicated rates for EV customers. ***(Practice)***
- While EV-specific rates with dedicated metering are common for both residential and commercial customers, they are not yet common for building heating systems. ***(Practice and Challenge)***
- In general, EV rate designs will differ in the balance among fixed, demand, and variable charges; the level of spatial granularity in demand and variable charges; and the level of temporal granularity in dynamic variable charges. ***(Practice)***

- Most existing residential EV rates are simple on-peak/off-peak TOU rates, though some rates incorporate seasonality and additional periods; most existing commercial EV rates are seasonal TOU rates with a demand charge, though to address near-term issues related to low utilization, demand charges often have discounts, deferred implementation, or sunsets (see LBNL *Snapshot* reading). ***(Practice and Challenge)***
- Upfront/sign-on incentives can be useful for attracting customers to dynamic prices, but the upfront incentives should be tuned at the right level. If they are too high, they could attract non-responsive customers; if too low, they may not attract risk-averse customers for which the incentive is the carrot.[6] ***(Challenge)***
- Only a small number of utilities have or have piloted rates combined with managed charging; most existing rate-control combinations are utility control programs in which customers can override the control signal (see *Snapshot* reading). ***(Practice)***
- In general, managed charging programs will differ in which party manages load (utility vs. aggregator or customer), how load is managed (e.g., fixed or dynamic limits, DR call, dispatch instruction), and the timing of load management (preset fixed vs. dynamic). ***(Practice)***

Examples of recent EV rates and programs are described in the table below:

UTILITY AND RATE/ PROGRAM NAME	RATE DESIGN NAME OR DESCRIPTION	MANAGED CHARGING COMPONENT
HECO EV-U Commercial Public Charging Rate	Quarterly TOU volumetric rates	Company may curtail charging service as needed.
HECO E_BUS	• TOU Volumetric rate • On-Peak Demand Charge	incentivizes charging times that coincide with solar generation and off-peak periods. Demand charge not assessed during incentivized time-periods
Tuscon Electric Power Residential Demand Super Off-Peak TOU Rate	• TOU Volumetric Rate • Residential Demand Charge	• TOU rate • Demand charge
Eversource CT Connected Solutions EV Managed Charging	Rewards for charging during Off-Peak Hours and for participating in 10-15 peak demand events. Advanced option to allow utility to schedule charging. Can enroll with L2 charger or vehicle telematics.	• Off-peak charging • Event based demand response • Utility managed charging
Xcel NM Optimize Your Charge	Incentive for Commercial Fleets to charge during off-peak periods at least 25% of the time	Off-peak charging incentive
San Diego Gas & Electric	EV High Power Rate	Offered to fleet customers to incentivize fleet electrification. The rate eliminates demand charges.
SDG&E Power Your Drive	Day Ahead Hourly Dynamic Rate	Hourly dynamic rates are set day-ahead based on CAISO day-ahead energy prices, with dynamic adders for the top generation and distribution peak hours.

6 See energyathaas.wordpress.com/2024/01/16/convincing-consumers-to-adopt-dynamic-electricity-pricing/

UTILITY AND RATE/ PROGRAM NAME	RATE DESIGN NAME OR DESCRIPTION	MANAGED CHARGING COMPONENT
Sacramento Municipal Utility District	Commercial EV rate	They charge a certain amount based on anticipated load for the customer business - they are seeing 10% savings.
Portland General Electric	TOU rate	Opt-in TOU rate but are studying commercial EV managed charging pilot (hoping to launch in 2025)
Con Edison Commercial Managed Charging Program (SmartCharge Commercial)	N/A programmatic	Program incentivizes all commercial customer charging stations (all vehicle classes and all use cases, such as public, fleet, workplace, multifamily etc.) to reduce EV charging during peak periods and increase EV charging during off-peak overnight. Incentives include two components: 1. Prorated $/per kW avoided during 4-hour peak network window relative to max potential site load, year round 2. Overnight off-peak charging kWh incentive for EV charging midnight to 8am (at the local network level during four-hour windows between 11 am and 11 pm)
Con Edison Residential Managed Charging Program (SmartCharge New York)	N/A programmatic	Program incentivizes light-duty EV drivers to charge off-peak. Incentives include two components: 1. $/month + bonus for avoiding charging during system peak June-Sep 2. Overnight off-peak charging kWh incentive for EV charging midnight to 8am
Con Edison Temporary Demand Charge Rebate	Off-bill 50% demand delivery charge rebate for public DCFC stations, available until EV Phase-in Rate is implemented	N/A
Con Edison Rider AD – Electric Vehicle Phase-In Rate (Expected 2025)	Available to commercial customers with at least half their load from EV charging. The delivery rate includes customer charge, demand charge, and TOU energy components: 1. Demand charge gradually phases in as station increases in load factor, from TOU component only at lowest load factors to 75% demand component up to 25% load factor) 2. TOU component includes peak period and super peak period	N/A

- A small number of utilities are offering locationally-differentiated rates (e.g., with distribution rates for different areas of the distribution system); the only example of locationally-differentiated rates in LBNL's Snapshot survey was SDG&E's Power Your Drive pilot. ***(Practice)***
- A small number of utilities are piloting programs that manage aggregated EV charging load at the feeder or service transformer level, which might be an effective tool for managing capacity. ***(Practice)***

- Evidence from pilots across the U.S., Europe, Australia and New Zealand suggests that EV customers are responsive to time-varying rates; however, the level of response depends on the customer type and other factors (e.g., fleet customers vs. residential).[7]
- This implies that at least simple TOU rates are a good first step in aligning charging behavior with system needs.
- However, whether EV and heating rates will evolve to more dynamic and advanced rate designs is still unclear; more sophisticated rates involve challenging allocation, fairness, and effectiveness questions. ***(Challenge)***
- The relative effectiveness of rates versus managed charging is not clear for different customer classes, "base" utility rates, and other factors. ***(Challenge)***
- Proactive investments in distribution capacity also involve challenging regulatory, cost allocation and fairness questions. ***(Challenge)***
- In this context, proactive investments refer to investments that are in advance of needs identified through the traditional distribution planning process.
- Recently initiated proceedings (for instance in the Minnesota Integrated Distribution Planning proceeding) may provide a venue for working through these questions.

CHALLENGES AND EMERGING PRACTICES – CONVENING DISCUSSION

Drawing on the Briefing Document, the group identified a comprehensive suite of challenges to consider:

- **Proactive investments** – the question of who bears the risks of investments represents a fundamental challenge to regulatory models, especially for DC fast charging for medium and heavy duty vehicles.
- **Cost recovery** – new rates introduce cost recovery risk for utilities ("recovering revenue requirement reasonably").
- **Cost allocation** – challenging to determine and balance a fair distribution of costs among customers. Issues include the potential for cross subsidies, a need for a complete understanding of value streams for all industry participants, and the challenge of managing the reality of rate design as both an economic and social program.
- **Affordability** – the need to design rates for affordability and include protections for low-income and highly energy-burdened customers. Issues include the fact that needed changes to rates will require customer ability to respond or delegate control, the need for sufficient enabling technology adoption for customer response, and regulatory barriers to DER aggregators in vertically integrated states.
- **Scalability** – rates need to be nimble enough to move beyond pilot to scale. Issues include challenges in customer enrollment.
- **Technology** – enabling technologies and standards for load management are emergent and not standardized.

7 See, for instance, https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/2/6442464904-2020-iou-lip-workshop-day-2-sdge-ev-tou.pdf and https://www.enelxway.com/us/en/resources/blog/everything-ev-drivers-should-know-about-time-of-use-energy-rates#:~:text=Consumer%20response%20to%20time%2Dof,in%20when%20it%27s%20most%20convenient.

- **Where to start** – lack of shared understanding about which part of the distribution system on which to focus and when to start.
- **Investment** – appropriate investment incentives to encourage private investment, ensure transparency and competition, and ensure utility investments are reasonable (planning challenge).
- **Locational value** – challenges of determining and transacting on locational value.
- **Regulations** – regulatory barriers to more granular rate classes (e.g., multiple residential classes).

Based on these challenges, the group finalized five objectives for what rates and incentives work should accomplish. These five objectives were used to test possible project ideas:

1. Promote customer adoption of beneficial electrification that saves consumers money, enables better grid management, or reduces negative environmental impacts.
2. Encourage connected load and load shapes that are cost effective for the grid now and in the future.
3. Fairly and equitably allocate costs and risks for investments to enable electrification, including anticipatory investment.
4. Encourage energy efficiency and system cost efficiency.
5. Promote sustainable, viable and flexible business models for utilities, equipment providers, and service providers that deliver on the above objectives.

LEAST-REGRETS SOLUTIONS – BRIEFING DOCUMENT

Recap of core challenges

- Balancing efficiency, equity, choice, customer understanding, and policy goals in rate designs.
- Finding an effective combination of rates, incentives and programs for achieving objectives.
- Adequately protecting low-income and moderate-income customers from unfair cost shifts.
- Developing acceptable regulatory frameworks for allocating the costs of proactive investments.
- Cost-effectively deploying billing, metering, IT and enabling technology

Potential least-regrets solutions

It may well be that rate designs continue to be very diverse across the U.S. Nevertheless, there are likely still some least-regrets solutions for rates and cost allocation, as described below.

Potential least-regrets rates and incentive solutions

(Entities responsible for implementation are in parentheses)

Offering some form of opt-in TOU rate for EV customers and special opt-in rates for commercial fleets (utilities)
Developing options for cost allocation frameworks for proactive investments, in white papers, planning proceedings, rate case proceedings, or other venues (utilities, commissions, stakeholders)
Reviewing current bill and connection protections for low-income customers and adjusting these as necessary to ensure they are robust to expected load growth (utilities, commissions, stakeholders)
Considering managed charging pilots or expanding existing managed charging programs (utilities)

LEAST-REGRETS SOLUTIONS – CONVENING DISCUSSION

The group incorporated some of the LRS into four project ideas, labeled A, B, C, and D. The table below shows whether the group incorporated a LRS into a project idea; whether it felt the LRS should be taken up in the next phase of CHARGED but did not neatly fit into a project idea; or whether the group did not incorporate the LRS or feel that it should be taken up in the next phase of CHARGED.

LRS FROM BRIEFING DOCUMENT	GROUP DECISION	DESCRIPTION OF HOW THE BRIEFING DOCUMENT LRS IS DEALT WITH
Offering some form of opt-in TOU rate for EV customers and special opt-in rates for commercial fleets (utilities)	Not taken forward in a project idea but should be considered in the next phase	The group recommended highlighting this least-regrets solution in the CHARGED effort going forward. The group recommended that these EV TOU rates should be opt-out rather than opt-in, assuming appropriate customer protections. The group noted the importance of designing TOU rates in a way that avoids 'cherry picking' structural winners.
Developing options for cost allocation frameworks for proactive investments, in white papers, planning proceedings, rate case proceedings, or other venues (utilities, commissions, stakeholders)	Taken forward in a project idea	Cost allocation as it relates to a narrow set of costs – secondary distribution investments, were a primary motivator of project idea D; the group did not dedicate significant time to cost allocation for proactive investments; the group flagged this as an important area for further work
Reviewing current bill and connection protections for low-income customers and adjusting these as necessary to ensure they are robust to expected load growth (utilities, commissions, stakeholders)	Taken forward in a project idea	Low-income customer protections are considered under projects B and D, where volumetric thresholds may delimit participation in specific rate designs; connection protections were not explicitly considered.
Considering managed charging pilots or expanding existing managed charging programs (utilities)	Not taken forward directly	The expansion of pilots was not explicitly considered, except insofar as project idea C is a strategy for expanding adoption through pre-enrollment of devices.

Two least-regrets solutions for potential exploration in CHARGED Phase 2 did not fall neatly into the four project ideas:

1. **Develop opt-out TOU rates for all customers and special opt-out rates for commercial fleets.** As above, this LRS built on the Briefing Document proposal, but with an opt-out rather than an opt-in design.
2. **Assemble a compendium of best practices on direct load control and demand response.** The group felt that this compendium would provide background information relevant to progressing all of the project ideas.

LONGER-TERM SOLUTIONS – BRIEFING DOCUMENT

Open questions and longer-term solutions

- Across several themes—rate design, managed charging programs, cost allocation and cost shifts, and internal and external data sharing—there are many open questions for rates and incentives:

  Rate design

  - » What current rate designs are best suited to managing electrification-related demand? What kinds of new rate designs are feasible and needed?
  - » How can we better understand customer demand elasticity related to charging, how that varies with vehicle range, income level, commute, which is important for considering charging flexibility?
  - » Should multi-part rates be optional? Are optional dedicated EV/heating rates the way forward? Do they need to be combined with mandatory TOU rates for all customers?
  - » At what point do more sophisticated dynamic rates compared to simple TOU rates become important for residential and small commercial customers (recognizing large commercial and industrial customers may already have dynamic rates)? What is the appropriate level of fixed charges (e.g., as a % of distribution costs that go into fixed charges) that can enable dynamic rates that are close to marginal costs?
  - » If it is deemed important to increase fixed/demand charges, how can utilities gain regulatory and stakeholder approval for higher fixed/demand charges in the context of broader innovations in rate design, given historical challenges in doing so?
  - » Should special rates be designed for aggregators to help achieve both locational distribution and system benefits?
  - » What should integrated rates for customers that have EVs or heat pumps, DG/DS, and load management technologies look like?
  - » What do VGI rates and programs look like? To what extent is it important to implement active VGI programs in addition to or as an alternative to rate design?

  Managed charging programs

  - » What is the role of rates vs. programs (and automated load management) at different points in the grid—for example, can pricing at the transformer level be used to manage load at the transformer level?
  - » How can lessons from numerous pilots be better disseminated and used for wider deployment by utilities?

- How do utilities move beyond scattered pilots for VGI? What do program design and incentives look like?

Cost allocation and cost shifts

- How should utilities/PUCs balance the competing goals of attractive rates to encourage electrification and managed charging against avoiding cost-shift by including more embedded costs?
- How should the costs of proactive distribution investments be allocated? Is this just about adding more spatial granularity to customer classification for cost allocation?

Internal and external data sharing

- How can utilities ensure that information on rates and customer response is being shared with utility planning departments and engineers?
- What kinds of customer and rate information should utilities share with individual market participants and aggregators? How can information be shared in a useful and secure format?
- What kinds of information should aggregators share with utilities? How can privacy and confidentiality issues be addressed?

PROJECT IDEAS – CONVENING DISCUSSION

Overview of projects

The group developed four project ideas (A, B, C, D) that contain elements of LRS and LTS, and are summarized in the table below. For each project, the table provides a title, identifies what type of project it would be, clarifies the problem that the project would address, and describes the kinds of changes that the project would enable.

	PROJECT A Advanced Rate Design Proceedings to Support Electrification	**PROJECT B** Residential Rates with Differential Control Thresholds to Support DER Management ("Do More Save More")	**PROJECT C** Opt-Out Load Management Rates	**PROJECT D** Subscription or demand charges for secondary networks and line transformers
Project type	Process Improvements	Pilot/Implementation	Pilot/Implementation	Rate design and cost allocation solution
Problem being addressed	Rate cases tend to be inflexible, meaning that they are usually multi-year processes, and are not responsive to changing distribution grid characteristics.	Utilities need an increasing array of tools to manage changing distribution grids as DER penetration increases. This should include load management, including via third-parties.	The adoption of rates that support load management are low, despite increasing adoption of DERs. There is enormous latent potential for these resources to enable equitable electrification, but only with increased enrollment and participation in suitable programs.	Modern rate design and cost allocation need to find better ways to allocate and price local network costs. Rates need to be able to fairly reflect cost allocations and orchestrate system-wide load management.

	PROJECT A Advanced Rate Design Proceedings to Support Electrification	PROJECT B Residential Rates with Differential Control Thresholds to Support DER Management ("Do More Save More")	PROJECT C Opt-Out Load Management Rates	PROJECT D Subscription or demand charges for secondary networks and line transformers
What the project would enable	Rate case structures will be reformed to expedite and improve the effectiveness of the process. Possible process improvements could focus on improvements to typical rate cases or parallel, non-contested proceedings; The project could focus on rate design only, or on revenue requirement, rate design, and cost allocation.	High energy use customers will be offered different rate designs to incentivize them to provide load management to their utility. Variations in rate design may include lower fixed charges, or avoidance of demand charges, in return for asset control.	DERs will be pre-enrolled at the point of sale into load management rates, supporting their mass adoption. A shadow billing period of one year may be used to assist with customer education. The ultimate goal is to support wider roll-out to whole-house load management rates.	Options that solve for customer acceptance and better cost allocation of these limited sets of costs may include limited residential demand charges, as well as subscription-based rate designs.

The remainder of this section describes each of the four project ideas, providing an overview ("Overview"), next steps for getting the project off the ground ("Next Steps"), and discusses requirements and remaining questions for consideration.

Project A: Advanced Rate Design Proceedings to Support Electrification

Overview

Project Specific Problem Statement

- Rate cases tend to feature limited opportunities for open stakeholder engagement and discussion of rate designs.
- Rate cases are often not able to move fast enough to adjust to changing electric grid conditions and technologies that support mass electrification.

Project Solution Type – Process improvements to support rate cases

Project Summary

The Advanced Rate Design Proceedings project is designed to improve some or all rate cases processes for efficiency, participation, and agility, in order to assess and scale solutions that work well. The group identified four options for how the project could progress, organized around process type (parallel or integrated) and coverage (rate design only or revenue requirement, rate case, and cost allocation).

- **Process type:** parallel to rate cases means establishing new processes alongside rate cases. These parallel processes would be informal and non-contested stakeholder participation opportunities to assess, compare, and develop rate case options outside of formal proceedings. Findings would feed into the formal rate cases via stakeholder contributions.
- **Process type:** integrated process improvements means the changes from this project directly affect the PUC rate case proceedings. For example, this may include changes to stakeholder working groups and data availability.

- **Coverage:** rate design only means only rate design is considered, and revenue requirement and cost allocations are not considered.
- **Coverage:** revenue requirement, rate case, and cost allocation means all elements of the rate case are considered in the project.

The table below describes each of the four options and their pros and cons.

	PROCESS TYPE: PARALLEL TO RATE CASES	PROCESS TYPE: INTEGRATED PROCESS IMPROVEMENTS
Coverage: rate design only	**Description** A stakeholder-driven process that takes place alongside a contested rate case. The parallel process focuses on rate design options and assessment. Stakeholders can informally work on rate design options, access data outside of formal processes, and surface new ideas outside of the contested rate case. **Possible Activities Within the Improved Process** Informal data sharing, rate design analysis, and comparison. **Trade-Offs** *Pros* Improved information sharing and ideation; supports novel and advanced rate design options. *Cons* Does not necessarily support rate case pace or agility.	**Description** Improvements to rate design processes that can be applied to full rate cases. Improved processes include PUC activities, ability for stakeholders to respond, pace and nimbleness of rate cases. **Possible Activities Within the Improved Process** PUC-led stakeholder workshops, iterative development of rate design options **Trade-Offs** *Pros* Accelerated and more agile rate design process. Surface novel and advanced rate design options. *Cons* PUC hesitancy. Some stakeholders may be less willing to participate in a contested process.
Coverage: revenue requirement, rate case, and cost allocation	**Description** A stakeholder driven process that takes place alongside a contested rate case. The parallel process covers revenue requirements setting, rate design options and assessment, and cost allocations. **Possible Activities Within the Improved Process** Informal data sharing, rate case analysis, and comparison. **Trade-Offs** *Pros* Rate cases benefit from extensive stakeholder insights. *Cons* Does not necessarily support rate case pace or agility.	**Description** Improvements to the full rate case process delivered by PUCs to support stakeholder engagement and responsiveness to changing grid conditions. May include more frequent or iterative rate cases. **Possible Activities Within the Improved Process** PUC-led stakeholder workshops. Iterative interactions or revenue setting, rate design, and cost allocations. **Trade-Offs** *Pros* Comprehensive process improvements. *Cons* PUC hesitancy. Some stakeholders may be less willing to participate in a contested process.

The group as a whole did not tackle the question of which of these options would be best to address the problem statement. The group did not have agreement on whether the project would focus on jurisdictions with contested rate cases, or whether it could apply to jurisdictions with non-contested rate cases as well. A reasonable compromise may be to develop a concept paper that allows for different approaches and can be applied to states' individual processes and policies. The inclusion or impacts of net metering and DER compensation was also raised. This was deemed out of scope, though some participants saw inclusion and consideration as key to holistic solution design.

The group identified two risks that need to be considered when developing this project. First, there is a risk that customers may be confused by the rapid changes taking place and feel disenfranchised. Suitable and accessible customer education is required. Second, the project will need to work with stakeholders to ensure ongoing support, while balancing the tension of bringing more stakeholders into the process and simultaneously proceeding apace.

Project Activities and Next Steps

The group identified four main activities for the project.

Concept paper – draft and publish a concept paper that captures the Advanced Rate Design Proceedings to Support Electrification project. The concept paper should focus on recommendations and process steps, rather than modeling of rate design approaches.

Considerations

- The breadth of scope for the project needs to be defined (i.e., process type—is this parallel to or part of rate cases? And for coverage—is this rate design only, or does it also include revenue requirement and cost allocation?)
- The content of the concept paper should prioritize which elements of rate cases can be incrementally progressed most readily.
- Options need to be assessed against how well they meet the two project-specific problem statements (stakeholder engagement, rate case pace to meet changing grid conditions).
- The concept paper should learn from New York, where some of these ideas have been considered, but remain slow to be implemented. New York may be a state to consider for engagement.
- The concept paper will need to consider the data requirements that utilities and PUCs should provide to support project implementation.

Workshop the project – the project should convene industry-wide stakeholders to establish how the project can best align rate cases and rate design with enabling electrification.

Considerations

- Establish who should be included in a workshop and the breadth of the project scope.

Proceeding implementation – work with willing states to implement the Advanced Rate Design Proceedings to Support Electrification project.

Considerations

- Target and engage with at least two states that are willing to pilot the project. Provide technical assistance to support these states.

Share findings – disseminate findings from the concept paper and project implementation.

Considerations

- Socialize outputs from the concept paper and any project implementation. Work with NARUC to support education and action planning in other states.

Requirements

Data requirements for the project – Significant new data may be needed to facilitate the creation of innovative rate designs specific to a utility's system needs and state policy goals. OEMs need to be able to access rate data to inform stakeholder discussions. The datasets themselves are to be determined.

Stakeholders required to advance the project – All industry stakeholders are key to project implementation. The development of a concept paper may require input from PUC staff and commissioners. State engagement would require engagement with PUC staff and commissioners, and potentially CHARGED participants with specific state knowledge and experiences.

Remaining questions – The detailed structure of Advanced Rate Design Proceedings to Support Electrification need to be defined. The actions that PUCs should take to implement Advanced Rate Design Proceedings are unclear.

Project B: Residential Rates with Differential Control Thresholds to Support DER Management (Do More Save More)

Overview

Project Specific Problem Statement

Participation rates in load control programs are not reaching levels desired by utilities to effectively manage the electric grid. Participation is generally characterized by customer fatigue and aversion to complex programs. Participation rates need to increase to support utilities to manage load.

Project Solution Type – Pilot/implementation project to use rate design to increase load management participation.

Project Summary

Different residential rate designs will apply to customers with consumption above a set peak load limit. These customers will be incentivized to provide load control to the utility in exchange for more affordable rate designs. Customers that retain choice over the amount of control they provide to the utility, however, will pay a premium in their rates for greater control.

Rate thresholds may include:

- Low rates (TOU and possibly lower fixed charges) for residential customers who enable full load control access (directly with a utility or via an aggregator)
- Medium rates (TOU) for residential customers who retain "asset overrides" of their energy assets
- High rates (could include: ToU/critical peak pricing/higher fixed charges/higher volumetric charges) for residential customers who retain "full self-control" of their energy assets

The original scope focused on "utility control." The group sought to widen the scope to include customers to engage with third party vendors, such as aggregators, to provide asset control. Third parties may offer more tailored customer propositions, and may be included in the scope of "asset controllers."

Project Activities and Next Steps

Analysis working group – establish a working group to analyze the different rate designs and thresholds between different rate designs. This analysis will likely require extensive utility and customer data to establish actual use and impacts.

Considerations

- The analysis working group should include diverse geographies and stakeholders.
- Locational as well as consumption-based triggers to load control thresholds should be considered. Analysis may need to consider, from a utility's perspective, what makes sense to offer residential customers based on their grid service requirements and what workable rate design solutions could include. The role of third-party aggregators should be included in the analysis.
- Analysis is likely a significant undertaking and may require third party consultancy support. The working group could help to support analysis.
- Consideration should be given to both the ability to access utility data and mitigate security, privacy, and resilience risks, and how the analysis can be suitable for multiple states with different demographics, energy use, and electric grid requirements. There may also need to be consideration of thresholds changing with time, for instance starting with very high consumption residents, and then lowering to include more customers over time.

Concept paper – share analysis and outputs, including recommendations on rate structures and thresholds. Outputs from the analysis work should be socialized with diverse stakeholders.

Implementation – pilot the project with willing utilities.

- Target states should be established for piloting the project.
- Group participants commented on the complexity of analysis and the need for dedicated support to undertake this work.
- There were social equity concerns to basing thresholds only on consumption rates, since high consumption may not necessarily equate to affluent customers, but could include overcrowded residences. This should be considered in threshold design.
- The group sought to create a continuous improvement feedback loop for pilot learnings to inform the analysis working group. Shadow billing may be suitable as part of any pilot to help understand bill impacts.

Requirements

Data requirements for the project – Extensive utility and customer data is likely required for this project. The exact data requirements are to be determined. Data confidentiality issues may be a challenge. Suitable data protection processes will need to be established for the analysis working group.

Stakeholders required to advance the project – A diverse analysis working group may assist in developing broad stakeholder input, enabling the pooling of experiences, data, and resources. Group participants commented that a diversity of stakeholders is needed to ensure buy-in to the project.

Remaining questions – Is there sufficient customer acceptance for the control thresholds approach to rates? Does the flexibility in control in this rate design approach improve participant uptake? How would this approach affect the phenomenon where many customers stop or start energy consumption at the same point in time? What are the impacts of different thresholds of rates on cost allocations between different customer segments? How will the overall project impact all ratepayers, as well as those participating (i.e., those above the consumption threshold)?

Project C: Opt-Out Load Management Rates

Overview

Project Specific Problem Statement

This project addresses limited residential customer enrollment in direct load control programs to support electrification. In particular, it is designed to take advantage of existing ratepayer-funded programs to ensure that customers participating in such programs are also managing electrified devices as resources on the grid.

Project Solution Type – Pilot/implementation project to scale opt-out load management rates through device pre-enrollment. Eventually, the project aims towards whole home load management rate adoption.

Project Summary

The project is designed to scale direct load control of customer owned devices. The project seeks to first support pre-enrolment of customer devices in load management rates at the point-of-sale. The project then intends to scale from device-level direct load control rates to whole-home load control rates.

The nature of the load control rates need to be established. The project assumes that enabling technologies, such as AMI, communications, and telemetry, are in place.

The group discussed that the means of device pre-enrolment needs further clarity, that incentives or discounts at device point-of-sale needed to be better understood, that the enabling technology assumption needs further assessment, and that the step between device to whole-home rates needs to be developed.

Project Activities and Next Steps

Industry/analysis working group – establish an industry working group to undertake analysis in support of the project.

Considerations

- Load management rate designs and their impacts need to be analyzed. For example, will rates include upside payments, curtailment, event-based impacts, time-varying rates, etc.?
- The overall impacts on enrolled and unenrolled customers need to be understood.

- Commercial arrangements between device manufacturers, utilities, and third parties, need to be established.
- The enabling technologies to support device and whole-home load management rates need to be well understood, so that the project can scale.
- The communications, telemetry, data standards, and other requirements may be complex and should be outlined.

Compendium of customer education best practices – Develop a well-researched resource for successful customer education. This will help to mitigate against the potential for participating customers to assume they will be exposed to negative bill impacts.

Considerations

- The development of a compendium of customer education best practices will require significant research and engagement with many stakeholders.

Concept paper – publish a concept paper outlining the outputs from the industry/analysis working group. Socialize the outputs from the industry/analysis working group to increase industry buy-in.

Implementation – establish partners for pilots. Work with utilities in CHARGED to partner with on the development of this project.

Considerations

- Define if there are specific devices or territories where opt-out load control could be first implemented.
- There may be many technical implementation complexities to scaling this project, especially between numerous OEMs, utilities and third parties.
- There is a need for comprehensive customer engagement, based on the customer education best practice compendium, to mitigate against presumptions of bill increases.

Requirements

Data requirements for the project – Data requirements and enabling technologies are likely to be significant for this project. There are currently no relevant standards on device or utility metering, data sharing, or data standards. The project may need to consider minimal viable data for delivery.

Stakeholders required to advance the project – Industry-wide stakeholders need to be involved in this project to ensure buy-in. The Compendium of Customer Education Best Practices should help mitigate against customer rejection, for example from "big brother" arguments. The group did not identify priority stakeholders; doing so would be an important next step if CHARGED takes this work forward.

Remaining questions – Are the technological enablers in place?

Project D: Subscription and/or Demand Charges for Secondary [Voltage] Networks and Line Transformers

Overview

Project Specific Problem Statement

The costs of grid upgrades to enable electrification, in particular secondary voltage networks and line transformers, are not well distributed via existing rate designs.

Project Solution Type – Rate solutions for cost allocation – the project analyzes options for rate designs that fairly distribute costs for investments to enable electrification.

Project Summary

The project considers subscription rates, demand charges, and time-varying charges as means to cover secondary network and line and transformer upgrade costs. The project considers residential, commercial, and industrial customers.

Residential customer options include:

- Small customer charge for metering and billing costs; modest cost-based demand charge covering secondary distribution costs where the cost causation of distribution demand is greatest.
- Subscription rate with dynamic direct load control (opt-in, with customer protections), similar to the French model of subscription based on demand.
- Time-varying energy charge, which could be bi-directional if sufficiently close to marginal cost.

Given the potential for controversy associated with residential demand charges, the group discussed the activities that may be needed for customer acceptance and response. These included shadow billing, robust customer education, opt-in-only structures, and residential classes so that those customers least able to respond are excluded from the program design (e.g., customers under 600 kWh per year of consumption, low-income customers)

Commercial and industrial (20-50 kW) customer options include alternatives to non-coincident demand charges that are more reflective of grid costs, potentially including:

- Time-varying (two-period) demand charge, with a coincident peak-based demand charge or subscription charge.
- Non-coincident peak demand charges limited to secondary distribution systems.
- Subscription or discounted tariffs for flexible, managed, or load shape-based interconnection.
- Hourly time-varying rate for generation and transmission.

Some participants proposed different project titles and terminology, in particular to avoid the term “subscription rates” since this may be controversial for some readers. Others commented that the title should have been “capacity-focused rate design,” though this was broader than the project content. Some participants commented that summarizing coincident peak management programs should also be included in the project scope.

Project Activities and Next Steps

Review advanced rate designs – define the case for improved secondary network and line transformer cost allocation, the mismatch between those costs and current designs, and the risks associated with inaction. Undertake a review of rate designs that include subscriptions or demand charges to articulate the tradeoffs and most promising options to address secondary network and line transformer costs. Analyze the scope of the challenge and the case for starting with improved cost allocation for this specific set of costs.

Considerations

- Examples of subscription and demand charges for residential and commercial and industrial customers will inform the data requirements and stakeholder approaches to successful rate design.

Analysis – define suitable subscriptions and demand charges, and required enablers.

Considerations

- Analysis should consider the types of charges and how they can effectively and fairly lead to cost allocations for line and transformer upgrades.
- Analysis should include considerations of what needs to be true to enable subscriptions and demand charges, including data and technical requirements. In addition, customer segmentation should be included in analysis to better understand how different customer groups may respond to and be impacted by subscription rates and demand charges.

Concept paper – Socialize outputs from reviews and analysis, specifically covering if and how a modest demand charge could be taken forwards, and what would need to be true to support that approach.

Implementation – establish state(s) to implement a modest demand charge.

Participants noted that different places have approved or implemented versions of subscription and demand charges already:

- Hawaii announced plans to implement a small demand charge.
- Tiered customer charges have been implemented in Burbank.
- kVa subscription rates have been implemented in France.

Considerations

- Target states should be established for piloting subscription rates or modest demand charges, if that is determined to be the best path forward.
- Implementation alongside more detailed customer segmentation of rates could also support some of the customer access and education issues noted in this group.

Requirements

Data requirements for the project – Data requirements are to be determined, but likely include utility and customer data to understand cost allocations and customer bill impacts.

Stakeholders required to advance the project – Utilities are key stakeholders to provide grid and customer data to assess cost allocations; consumer advocates are key stakeholders to provide insights and representations of customer needs.

Remaining questions – Which of the potential rate design options is most suitable for addressing cost allocation of secondary network costs in a way that is acceptable to customers? What is most acceptable for customers and other stakeholders, such as third-party providers of electrification devices or services?

Participants noted that terminology may be very challenging for stakeholders, both due to complexity, and the risk of alarming stakeholders. Care should be taken to explain terms fully and to limit jargon.

READING LIST

Pre-workshop suggested reading

Note, the "pp." refers to the page numbers as indicated in print on the document, while the PDF pp. refers to the page number as it appears at the top of the PDF viewer tool.

- Cappers et al., *2023, Snapshot of EV-Specific Rate Designs Among U.S. Investor-Owned Electric Utilities*, Lawrence Berkeley National Laboratory, Executive Summary, pp. v-ix (PDF pp. 8-12), eta-publications.lbl.gov/sites/default/files/ev_rate_snapshot_report-final-20230424.pdf
- ESIG, 2024, *Charging Ahead: Grid Planning for Vehicle Electrification*, pp. 28-43 (PDF pp. 41-56), esig.energy/grid-planning-for-vehicle-electrification
- E3, 2023, *Rate Design for the Energy Transition: Getting the Most out of Flexible Loads on a Changing Grid*, pp. 22-28 (PDF pp. 25-31), esig.energy/wp-content/uploads/2023/04/ESIG-Retail-Pricing-dynamic-rates-E3-wp-2023.pdf

Additional references

- Peter Cappers and Andrew Satchwell, 2022, *EV Retail Rate Design 101*, eta-publications.lbl.gov/sites/default/files/ev_tariff_design_101_final.pdf
- Carvallo and Schwartz, Lawrence Berkeley National Laboratory, 2023, *The use of price-based demand response as a resource in electricity system planning*, pp. 19-20, eta-publications.lbl.gov/sites/default/files/price-based_dr_as_a_resource_in_electricity_system_planning_-_final_11082023.pdf
- Melissa Whited, Jason Frost, Ben Havumaki, 2020, *Best Practices for Commercial and Industrial EV Rates*, synapse-energy.com/sites/default/files/Best_Practices_for_Commercial_and_Industrial_EV_Rates_18-122.pdf
- Melissa Whited, Avi Allison, Rachel Wilson, 2018, *Driving Transportation Electrification Forward in New York: Considerations for Effective Transportation Electrification Rate Design*, synapse-energy.com/sites/default/files/NY-EV-Rate-%20Report-18-021.pdf
- GreenBiz, 2022, *Advanced Rate Designs Harnessing Vehicle-Grid Integration Technology*, greenbiz.com/whitepaper/advanced-rate-designs-harnessing-vehicle-grid-integration-technology
- The Mobility House, *2023, Automated Load Management: The Technical guide for EV fleet charging*, mobilityhouse.com/usa_en/knowledge-center/whitepaper/alm-guide-fleet-charging
- ESIG webinar, *2022, Vector Limited, EV Smart Charging Trial*, esig.energy/event/webinar-ev-smart-charging-trial (presentation, recording, Q&A available)

TARGETED AND INTEGRATED DEPLOYMENT

OVERVIEW

Improving program design, targeting, and integration (for example, through analytics, coordination across the utility) can increase both (a) the adoption of electrification measures and (b) customer utilization of electric vehicle (EV) rates and heating rates and programs aimed at increasing demand flexibility and reducing distribution costs.

Utilities have experience with demand-side management (DSM) programs—energy efficiency, demand response, distributed generation and storage. However, electrification may create new opportunities for improving utility program design, targeting, and integration (co-deployment). Additionally, most utilities do not currently use DSM programs to address local distribution system needs, although technological innovation and load growth are also creating new opportunities to do so.

The objective of this workstream is to develop a consensus set of least-regrets strategies for improving utility program design, targeting, and integration in the context of electrification, and to identify and prioritize longer-term gaps in programs that the industry can start to address in the nearer term. This workstream did not cover non-wires procurement.

This chapter is organized into the following main sections:

- **Challenges and emerging practices**
- **Least-regrets solutions**
- **Longer-term solutions**
- **Data requirements**
- **Reading list**

The first three sections contain material from the Briefing Document, which attendees received prior to the convening, and summarizes the convening discussions of the deployment group. The data requirements section synthesizes how data sharing was discussed by the deployment group. The reading list section is background reading that was provided to participants in the Briefing Document.

CHALLENGES AND EMERGING PRACTICES – BRIEFING DOCUMENT

For ease of reading, we have identified practices and challenges with labels throughout this section.

General program design

- While program evaluation is an existing tool, the results of evaluations are often not publicly available. More mid-term evaluations and sharing results of evaluations—or at minimum, lessons learned—could help accelerate deployment of DSM measures in the future across the industry. ***(Challenge)***
- Current program practice misses opportunities for information tracking that can inform evaluations and help continuously improve program design. Better records (program tracking data) of each intervention are needed to track program effectiveness and understand the current market as well as trends (e.g., tracking if heat pump installation is part of a full or partial replacement; are integrated controls being installed if the latter, including building-flexibility capabilities). As an example, TECH Clean CA[8] provides detailed heat pump program data that enables transparent tracking of effectiveness. ***(Challenge)***
- Some data gaps remain for strong electrification program design—for example, while there is significant program information on demand response and load flexibility for traditional measures focused on summer peaking (e.g., air conditioning load management), there is little data in the industry on the performance of winter demand response events in the electric system. ***(Challenge)***
- Many programs have insufficient customer service and education practices. The ESIG EV whitepaper (see ESIG, 2024) emphasizes the importance of customer-collaborative processes to identify the best solutions for EV charging, program participation and flexible interconnection. ESIG noted the importance of more clearly describing timelines and processes to customers (e.g., Oncor's Clean Fleets Partnership Program includes educational materials for fleets, such as on the difference between screening maps and detailed interconnection analysis, and collects information from fleets on operations and electrification potential.) ***(Challenge and Practice)***
- Communication gaps between utilities, program administrators and contractors in the context of electrification programs and grid hosting availability has led to canceled projects. In some cases, customers have signed up for programs to later find that grid upgrades will delay the work by several months. Better and regular coordination among utility departments and with program administrators and contractors is important, particularly for awareness on hosting capacity and grid upgrades. ***(Challenge)***

Targeting for adoption, grid constraints, and equity

- Targeting customers for grid constraint management will require more coordination across utility departments than is typical practice, and creating robust information sharing processes and platforms. This goes both ways: planning may benefit from many different data available from program activities—for example, efficiency of equipment, targeted installations per year, adoption rates. Conversely, targeted program design requires planning and operational information on grid constraints. ***(Challenge)***
- Targeting specific customer types will require more granular tools—coupling information on likelihood of adoption, community specific characteristics, demographic, housing information, priority customers. Programs which seek to address inequities may require additional information on local environmental conditions such as air quality. ***(Challenge)***

8 techcleanca.com

- The inclusion of technical specifications and "grid-readiness"[9] measures on the customer side of the meter will aid in avoiding grid congestion—minimum energy efficiency standards[10] (e.g., Efficiency Maine includes higher rebates for efficient heat pumps); demand-response ready capabilities such as CTA2045 or WiFi for heat pumps (e.g., CTA 2045 ports are required for all new electric storage water heaters in Washington and Oregon as of 2023); and selection of automated load management software that avoids redundant utility investments. The ESIG EV whitepaper noted a number of opportunities for improved ALM that can help avoid redundant utility protection equipment—third party testing, and UL standards and certifications (UL 916 and UL 60730-1 are potential standards). ***(Challenge and Practice)***
- It is not clear what the "best" ways are to support adoption of electrification measures in disadvantaged communities since these customers experience multiple barriers to adoption of electrification measures (e.g., high capital costs, split incentive barriers), and such efforts are young. However, emerging practices include (1) setting a fraction of program funds for disadvantaged communities with higher rebate values (e.g., heat pump rebates from Efficiency Main and Mass Save, make-ready rebates only available for fleets located in underserved communities, such as with Seattle City Light); (2) rebates for new/used EVs only available to customers in DACs (e.g., as done in California) and technical support and guidance for DAC-specific EV rebate programs (e.g., MAAC EV access program[11]). Creating an ecosystem to support customers in DACs will likely require a holistic approach that goes beyond rebates. ***(Challenge and Practice)***

Integrated deployment

- Fleet electrification is a special load growth case and requires development of new methods, partnerships and tools by utilities—for example, a database tracking customers with fleets, holistic program offerings and partnerships with these customers, new partnerships with vehicle dealers, cities, transit authorities, and others. ***(Challenge)***
- As an example, Eversource has created partnerships—with OEMs to collect vehicle behavior data in anticipation of forthcoming electrification; to inform building electrification, they have partnered with a Town/City Building Permit and Development Authority to receive alerts based on building permitting. ***(Practice)***
- Program delivery has historically been siloed to specific technologies rather than integrating multiple technology offerings into a single program containing one interaction with a customer, which results in lost opportunities for grid management. Similarly, electrification programs often neglect offering rates or load control measures. Co-deployment of electrification measures and different DSM measures will be increasingly important for grid reliability—e.g., fleet electrification programs that provide charger rebates and make-ready incentives do not always offer a time-varying rate or managed charging option. Similarly, co-deployment of efficiency, electrification, resilience, and demand response opportunities, along with relevant rates or automated load management programs are emerging opportunities. ***(Challenge)***

9 Grid readiness on the utility side is discussed in grid connection.

10 Efficiency in this context refers to the efficiency of the heating device being installed, but could be broadened to include additional whole-building measures that lower heating requirements.

11 maacproject.org/ev-access

- Electrification will need to be coordinated with gas system decommissioning to avoid costly and unnecessary network investments on both sides. Some jurisdictions have begun to explore targeted deployment in the context of gas distribution decommissioning. In principle, targeting gas customers where few customers are connected is an economical place to begin from a total resource perspective (See Gridworks and E3 2023a and 2023b for information on the Northern California gas decommissioning pilots[12]) ***(Challenge and Practice)***
- Coordinating electrification programs for customers with propane or fuel oil heating may be an effective strategy for electrification—for example, states in New England are supporting heat pump deployment for customers with oil-based heating. ***(Challenge and Practice)***

The following case studies offer important insights on grid flexibility, program delivery, and other aspects.

UTILITY/ STATE/ JURISDICTION	APPLICATION *(e.g., grid flexibility, targeted deployment, integrated deployment etc.)*	DESCRIPTION
Efficiency Maine/ ME and MassSave/ MA	Program funds to equity/DACs	Some electrification programs have a percentage of the program funds targeted to disadvantaged communities offering higher rebates for these customers.
CA (state and utility partnerships)	Funds available for DACs	Offers rebates for purchase of used and new EVs for income eligible (IE) customers living in DACs
MAAC (nonprofit in CA)	Education and technical support for EV adoption	Supports IE customers to apply for rebates and financing, offers technical support and guidance for vehicle selection
CT/MA/NY/ME	HP program design	Sets minimum efficiency standards for the products that are eligible for rebates (NEEP or Energy Star V6.1)
MA	HP program design	Higher rebates if weatherization and HPs are coupled
PSE	Managed charging	Fleet customers are automatically enrolled in passive managed charging
ME	HPWH program design	Contractor-centric program that offers multiple resources for contractors to participate in the program, including rewarding top performers with more work
WA/OR	Grid flexibility readiness	These jurisdictions require that all HPWH sold include CTA 2045 port receptacles.
Northwest Energy Efficiency Alliance (NEEA)	Grid flexibility readiness	AWHS v8 requires CTA 2045 ports or equivalent open source modular interface for all residential equipment.
Xcel Home Wiring Rebate Program	EV adoption and managed charging	Provides rebates for level 2 charger in exchange for participation in rate programs
Con Edison, New York	Managed charging for charging stations to provide operating cost relief and encourage grid beneficial behavior	Behavioral managed charging for all vehicle classes and all commercial customer station use cases, such as public, fleet, workplace; station operators incentivized to reduce or avoid charging during network peak hours and charge over-night

12 gridworks.org/initiatives/gas-decommissioning

UTILITY/ STATE/ JURISDICTION	APPLICATION *(e.g., grid flexibility, targeted deployment, integrated deployment etc.)*	DESCRIPTION
Con Edison, New York	Managed charging for light-duty vehicle drivers to provide operating cost relief and encourage grid beneficial behavior	Behavioral managed charging for light-duty EV drivers to charge off-peak
Con Edison, New York	EV charging load management technology to support grid beneficial charging behavior Awaiting regulatory approval	Incentives for EV charging demand management technologies; eligible technologies include on-site or charger integrated energy storage and advanced load management software
Con Edison, New York	Make-ready incentive adder to support EV charging build-out for light-duty cost efficiently and speed interconnection timelines	Incentive adder for projects that include load management technologies

CHALLENGES AND EMERGING PRACTICES – CONVENING DISCUSSION

The group first reflected broadly on the types of challenges that encompassed the categories of general program design, targeting and integrated deployment. There was general agreement with the challenges listed in the Briefing Document. The group found these overall categories to be logical but noted that customer electric readiness (such as having an adequately sized home electric panel) may be its own category of challenges.

The group discussed key challenges such as customer awareness, contractor education, lack of data especially for winter demand response, insufficient coordination among utility departments (planning, programs, operations, etc.) and between gas and electric utilities, and customer readiness issues like inadequate electrical panels. A lack of information and experience on programs that target locational grid constraints was noted; for example, utilities do not have mechanisms to direct new customers to areas where capacity exists. While AMI data can, in theory, support targeting, deficiencies in analytical tools that analyze AMI data were noted.

Additional challenges mentioned were utility speed/nimbleness, new customer types (such as for truck charging) lack familiarity with how utilities work, and a question of who pays for infrastructure upgrades. The group ranked the various challenges presented in the Briefing Document. The top 2 challenges that emerged within each theme are shown below:

GENERAL PROGRAM DESIGN	TARGETING	INTEGRATED DEPLOYMENT
Lack of program data tracking which can inform better program design	Insufficient coordination across utility departments (especially with respect to targeting for grid constraints)	Utilities are not pursuing co-deployment (e.g. electrification with efficiency and/or load control, time-varying rates)
Insufficient customer service and education	Lack of customer equipment and grid readiness (e.g., min efficiency standards to avoid congestion, wiring upgrades)	Fleet customers are a special load growth case and new program methods are required to onboard them

The group conducted an exercise to delve deeper into challenges, exploring underlying tensions and mental models contributing to these challenges. These included utilities being risk-averse and slow to change, individuals not incentivized to go beyond their defined roles, consumer distrust of utilities, and lack of enterprise alignment within utilities.

LEAST-REGRETS SOLUTIONS – BRIEFING DOCUMENT

Recap of core challenges

- Using DSM programs to provide distribution-level services may require changes in program design, including incentives, targeting of specific customers, and coordination within and outside utilities.
- Silos within utilities limit visibility between program and planning groups, limiting the development of programs to target grid constraints and make programs more cost effective.
- Utilities are not pursuing co-deployment of different kinds of programs, including measure deployment, DSM programs or rates.

Potential least-regrets solutions

Least-regrets solutions for programs focus on the core themes of general program design, data sharing, targeting, and integrated / co-deployment. They are listed in a proposed order of importance.

Potential least-regrets solutions for targeted and integrated deployment strategies

(Entities responsible for implementation are in parentheses)

1	Using planning data, program evaluations, and data analytics to better target and design DSM programs where there are expected distribution capacity needs (utilities)
2	Ensuring that evaluation and/or implementation data that contain valuable information about customers (e.g., adoption trends, EV and HVAC characteristics including load shapes) is available to other utility departments (utilities, commissions)
3	Promoting co-deployment of DER and EE programs with load management programs (e.g., coupling DR programs with heat pump water heaters deployment through rebates) (utilities, commissions, stakeholders)
4	Exploring opportunities for making evaluation results publicly available, for instance in studies aggregated across multiple utilities (utilities, commissions)
5	Reviewing current load management programs (e.g., interruptible DR programs) to determine their applicability to provide distribution services (utilities)
6	Partnering with aggregators or allow them to bid into residential and commercial programs (e.g., interruptible tariffs), since they have visibility into deployed measures that are controllable (utilities)
7	Improving coordination among programs, planning, and rates (e.g., processes, data management and sharing, cross-training of staff) (utilities)
8	Integrating efficiency requirements in electrification programs (e.g., setting minimum efficiency for chargers and heat pumps (or COP requirements at 5F for HPs) or comply with energy star or NEEP for cold climate or others) (utilities, commissions)
9	Targeting heat pump programs (along with adjacent DSM programs) towards residential customers currently using propane and oil for heating, or electric resistance heating. Where replacements are already cost-effective, programs can focus on education/awareness (and not necessarily require a large rebate component) (utilities)
10	Creating an ecosystem to support electrification in disadvantaged communities, such as set-aside funds, co-deployment of all qualifying DSM programs in a building, technical support for applying to rebates/financing[13] (utilities, local governmental agencies, non-profits)

13 See this example of offering support to apply for rebates/incentives targeted at DACs maacproject.org/ev-access

11	Exploring coordination for targeted electrification with gas infrastructure decommissioning (utilities, commissions)
12	Establishing partnerships with local and regional fleet associations, heat pump contractors and distributors, to improve program design, marketing, education and delivery to this sector; consider prioritizing fleets that operate in disadvantaged communities (utilities, industry)

LEAST-REGRETS SOLUTIONS – CONVENING DISCUSSION

Overall discussion

The group began with an open discussion on the prepared list of least-regrets solutions (LRS) with the objective of validating each LRS, then adding, clarifying LRSs as appropriate, and then finally moving LRSs to be considered as longer-term solutions. To facilitate discussions, the list of twelve LRS were categorized into the three categories of general program design, targeting and integrated deployment, and simplified nicknames were developed to facilitate group activities using large post-it sheets.

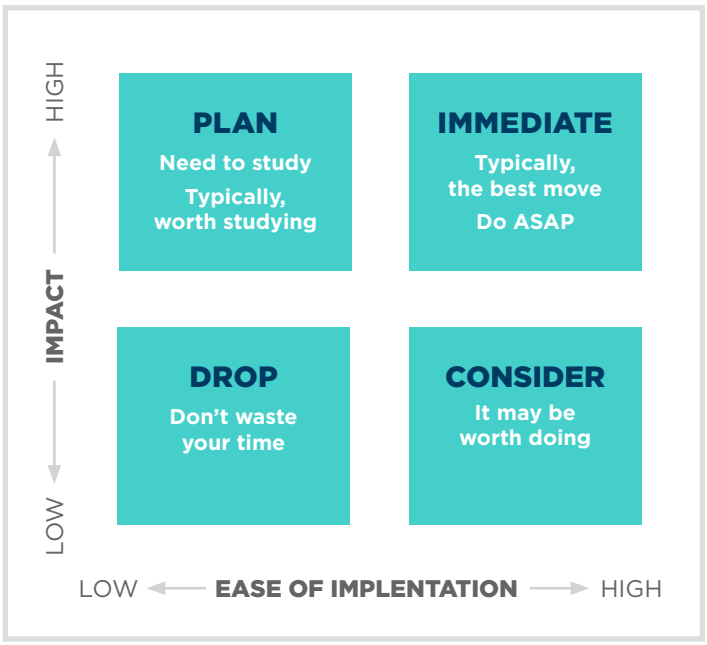
ORIGINAL RANK	NICKNAME OF LEAST-REGRETS SOLUTION	CATEGORY
1	Data-informed DSM programs	General program design
2	Utility department data sharing	General program design
3	Co-deployment	Integrated deployment
4	Public program evals	General program design
5	Load management for Dx system services	General program design
6	Partner with aggregators	General program design
7	Utility department coordination	Targeting
8	Efficiency requirements	Integrated deployment
9	Targeting for propane and fuel oil	Targeting
10	Ecosystem for disadvantaged communities	Targeting
11	Gas decommissioning	Integrated deployment
12	Industry partnerships	General program design

Regarding LRS 10—creating an ecosystem to support electrification in disadvantaged communities (DACs)—it was noted that this seems difficult and that there will be a longer-term component; however, given its importance, some elements could be considered at the outset as a LRS, deferring the more challenging components to be part of a LTS. In addition, LRS 7 (improved coordination among utility departments) was split into two components to match the general categories—LRS 7(a) improve coordination between programs, operations, interconnection was placed under integrated deployment and LRS 7(b) improve coordination between planning, forecasting, programs for targeting was placed under targeting.

Three new LRSs were developed (nickname followed by description and responsible entities):

- **Customer-centric programs** – Streamline the customer experience and make program delivery customer-centric (e.g., single point of contact) (responsible entities: Utilities, program administrators)
- **Portfolio key performance indicators (KPIs)** – Define shared KPIs that the program portfolio should be working toward (responsible entities: Utilities, program administrators)
- **Data standardization** – Explore opportunities for data standardization and validation (responsible entities: Utilities, commissions)

The group felt that customer-centric programs are important. The key point was that the customer experience needs to be a governing principle in how programs are designed to ease customer participation and engagement. This may include, for example, a single point of contact or a single website for the entire suite of programs. While several participants noted that a single point of contact can be quite helpful, others noted it may also make the process more complex; as such, each utility may need to assess which streamlined approach is most appropriate.



Prioritization

The group ranked the top least-regrets solutions using a prioritization strategy that considered the impact and ease of implementation. Impact was defined as meeting the goals of the CHARGED initiative.

The results of the prioritization activity are shown below.

CONVENING RANK	ORIGINAL RANK	NICKNAME OF LEAST-REGRETS SOLUTION / POINTS	CATEGORY
1	7	Utility department coordination	Targeting
2	3	Co-deployment	Integrated deployment
3	12	Industry partnerships	General program design
4	(New)	Customer-centric programs	General program design
5	(New)	Portfolio KPIs	General program design
6	1	Data-informed DSM programs	General program design
7-8 (tie)	6	Partner with aggregators	General program design
7-8 (tie)	(New)	Data standardization	General program design
9-10 (tie)	4	Public program evals	General program design

CONVENING RANK	ORIGINAL RANK	NICKNAME OF LEAST-REGRETS SOLUTION / POINTS	CATEGORY
9-10 (tie)	8	Efficiency requirements	Integrated deployment
11-15 (tie)	2	Utility department data sharing	General program design
11-15 (tie)	5	Load management for Dx system services	General program design
11-15 (tie)	9	Targeting for propane and fuel oil	Targeting
11-15 (tie)	10	Ecosystem for disadvantaged communities	Targeting
11-15 (tie)	11	Gas decommissioning	Integrated deployment

The top 3 least-regrets solutions from the prioritization activity were:

- Improving coordination between utility departments
- Co-deploying energy efficiency with load management, and
- Establishing partnerships with industry stakeholders

Participants noted, in spite of the prioritization results, that all the LRSs listed, including the additional 3 new LRSs are important.

Detailed discussion on prioritized least-regrets solutions

The group split into subgroups to develop the three priority LRS and then solicited feedback from the larger group. The overall objective was to identify how these top 3 least-regrets solutions could become widely adopted throughout the industry. The discussions of the three priority LRS were organized around actions, barriers, stakeholders, enablers, practices, and timeline.

LSR 1: Improve Utility Department Coordination

Action / what can be done	• Establish company-wide vision, mission, KPIs, roadmap (C-level driven) • Establish cross-functional group within utility • Information exchange across departments • Internal incentives/rewards for performance • Establish customer advisory group
Barriers / why is this not happening already?	• It's a new need and there is a lack of leadership • Risk aversion • No incentive to do so at the individual and leadership level • Lack of motivation • Status quo with culture and inter/intra department relationships
Who Needs to Act?	• Can be accomplished within the utility only • C-suite need to create the vision • Departmental leads (implementing the vision) • Cross-functional group refine and improve implementation • Customer advisory group informs utility on pain points, planning processes, and what data certain customer types (e.g. fleets) have available
Enablers	• Integrated data platform for information sharing/access
Timeline	• Year 1: Create vision and cross functional group • Year 2: Information exchange • Year 3: Customer advisory group established

The team that developed this LRS shared the above characteristics with the broader group. Feedback from the broader group included the following:

- Participants echoed that utilities need to break down existing silos and barriers
- One participant noted the importance of organizational culture and questioned whether a bottom-up approach may help achieve this LRS, in contrast to the top-down approach described
- Another participant noted their experience in how utilities are trying to break down the silos using a bottom-up approach and engaging engineers more in the implementation

Following the April convening, the group met again virtually. Participants felt this timeline could be made more aggressive. For example, the step of evaluating and growing efforts could be achieved in year 1 and the process could be up and running by year 2.

LSR 2: Co-deployment

Action / what can be done	• Identify and communicate the value to the customer and the utility • "Pancake" existing siloed programs so that customers can enroll in multiple synergistic programs simultaneously • Develop comprehensive program success metrics • Simplify/streamline the customer enrollment process and experience • Design tech-neutral programs/incentives and/or establish a menu for technology eligibility • Develop performance requirements for discrete services provided
Barriers / why is this not happening already?	• Lack of workforce development to implement controls and electrification technologies • No regulatory requirements • Internal utility silos • History of controls failures • Outreach and education • It's new
Who Needs to Act?	• Utility distribution planning dept • Utility distribution system operators • Regulators • Customers + community organizations • Program administrators • Aggregators • Installers/contractors • Equipment manufacturers
Enablers	• Data: Load/generation forecasts, customer meter data (sufficiently granular and available in a timely manner) • Technology: AMI, controllable devices/equipment, basic DERMS system • Practice: customer and installer education, program evaluations, identify services and location needs
Timeline	• Motivated cooperatives with motivated members may be the easiest path to implementation

The team that developed this LRS shared the above characteristics with the broader group. One point shared in the feedback was that co-deployment should include a component of rates. Another participant noted that their program does indeed include a component of rates.

LSR 3: Establish industry partnerships

Action / what can be done	• Build an ecosystem of program engagement partnerships - Customer lists: those in the queue already, potential customers not yet engaged - Contractor list: for training, vetting, and providing input • Create a tailored outreach and marketing plan to engage partners who stand to mutually benefit from better program design • Establish bi-direction communication – public program data and evals, customer data to the utility, and utility to customers with opportunities for co-deployment/ time-varying rates • Offer rewards/recognition for top performers
Barriers / why is this not happening already?	• Lack of information/structure • Not clear what the value proposition is • Cost/complexity • Unclear opt-in/opt-out structure • Vetting and validation
Who Needs to Act?	• Utility • Distributor reps • Contractor and customers on the engagement lists • Fleets • State agency offices • Municipal governments
Enablers	• Data: customer data to utilities (especially for customers like fleets) – profiles and project scale, geographic data • Practice: Outreach, project aggregation, simple processes for engagement, utilize input to inform utility planning pipeline
Timeline	• Next 3 years

The team that developed this LRS shared the above characteristics with the broader group. One participant noted how successful utilities need to "hit the pavement" to develop these partnerships and have regular communications. Another participant echoed the importance of including multiple agencies in this outreach, including state and municipal agencies.

LONGER-TERM SOLUTIONS – BRIEFING DOCUMENT

Open questions and longer-term solutions

- Open questions for deployment are grouped around the themes of general program design, targeting, and integrated deployment.

  General program design

  - » What steps should be taken to ensure that program lessons and data are shared broadly and with all relevant actors? Given electrification programs are somewhat new, how can midterm/midstream insights be shared for others to benefit?
  - » How can utilities better engage with contractors and distributors?
  - » What platforms can better facilitate sharing of program data within utilities?
  - » What data on historical program marketing and implementation should utilities share with commissions and third parties?

- What program data should be collected to truly assess program impact and opportunities for DSM programs?

Targeting for adoption, grid constraints, and equity

- How can different programs be better targeted for adoption, location and equity?
- What are the analytical practices that can improve program targeting, such as load disaggregation using AMI data to target program measures?
- How can distribution system planning inform target areas for program deployment either in areas of grid constraints or historically underserved communities?
- How can programs, planning and other relevant teams work together to target programs for managing / avoiding grid stress?
- How should utilities better target electrification programs and incentives to fleet customers?
- To what extent would distribution-focused DSM programs for electrification change the way that utilities do DSM?
- Are electrification-related DSM programs scalable to a level that will meaningfully reduce electrification-related distribution investments? If not, are they still worth doing?
- What is the role of utilities vs. aggregators in implementing targeted DSM programs?
- How can programs be designed for equitable outcomes?

Integrated deployment

- How can different programs be better integrated? How can electrification programs be coordinated with the retirement of gas distribution systems?
- What opportunities are there to co-deploy electrification incentives and DR/DSM programs?
- To what extent should DSM programs be twinned with rate options (e.g., if you pick rate X you need to be part of program Y)? Will that be a deterrent to rate adoption?
- What standards should be required as part of electrification programs for enabling load flexibility, such as CTA-2045?

LONGER-TERM SOLUTIONS – CONVENING DISCUSSION

Overall discussion and prioritization

Utilizing the same impact versus implementation criteria, the group reviewed the list of longer term questions and topics in the Briefing Document and selected the top two issues and crafted problem statements to help inform phase 2 project ideas.

Two problem statements were developed.

- **Problem statement 1:** Utilities are not publicly sharing lessons learned from program implementation, which limits the success of future programs and the speed of deployment.
- **Problem statement 2:** Utilities lack good practices to use available data to inform program strategy. This creates barriers for (1) targeting grid constraints; (2) avoiding costly upgrades; (3) effective program delivery; and (4) addressing equity issues.

Project outlines were then developed to address the problem statements. To address Problem statement 1, one group pitched an idea to improve program design using existing program data ("Program Design 2.0"). To address Problem statement 2, another group pitched a LTS project to develop an integrated data platform and accompanying playbook to enable utilities to better leverage data for targeted program design.

Detailed discussion on prioritized LTS

The group developed the following outlines for the two projects:

PROJECT	PHASE 1	PHASE 2
Program Design 2.0 by leveraging existing program data	Build data repository and set data standards • Data audit – what's missing? Who needs it? For what? • Create data standards/templates for reporting/sharing	Multi-utility pilot • Small number of IOUs, munis, coops engage in program pilots utilizing data repository to inform program design • Publish lessons learned
Integrated data platform	Develop playbook (public) • Purpose is to have one data platform to inform strategies, program design, and customer targeting to address grid conditions	Small utility pilot • Build "MVP" data platform • Pilot at a small utility • Publish lessons learned

Although these two project outlines were developed independently by different groups, both project designs include a phase 1 that is a design phase, and a phase 2 that is a pilot phase.

DATA REQUIREMENTS

While the group did not have a specially dedicated discussion on data requirements, data was a central theme of the discussions, from challenges to the LRSs and LTSs discussed. In fact, two of the LRS prioritized—the LRS "improve utility department coordination" and LRS "establish industry partnerships" — and both LTS projects are data focused. The categories of data discussed included both intra-utility data sharing and data sharing between the utility and external partners.

READING LIST

Pre-workshop suggested reading

Note, the "pp." refers to the page numbers as indicated in print on the document, while the PDF pp. refers to the page number as it appears at the top of the PDF viewer tool.

- PGE, *Transportation Electrification Plan 2023*, assets.ctfassets.net/416ywc1laqmd/2xv3CdVdbyaZuYVy3UFWkR/65122d294f36a14ee6514cab2cf6fb74/TEP_2023-08-25_Full_Report.pdf (*overall transportation electrification strategy and cross-cutting foundations*)
  - » Summary for Policymakers, pp. 1-2 (PDF pp. 15-16)
  - » Chapter 6, Foundations, pp. 88-96 (PDF pp. 102-109)

- ACEEE, 2022, *Building Electrification: Programs and Best Practices*, aceee.org/sites/default/files/pdfs/b2201.pdf (importance and scarcity of evaluation data; lessons from programs)
  - » Conclusions and Recommendations, pp. 64-66 (PDF pp. 75-77)
- Itron, *Central Hudson Gas & Electric Peak Perks Targeted Demand Management Program*, pp. 1-2 (This document is no longer available on Itron's website; please contact us for a copy)
- Association for Energy Affordability, *PG&E WatterSaver Program, 2023 ACEEE Hot Water Forum 2023 presentation*, pp. 10-11 drive.google.com/file/d/1XbaC8Mo50PT9U4jSKzJKxYhyFFMmAR_2/view *(lessons from a demand flexibility program)*
- Xcel Energy, *Home Wiring Rebate*, ev.xcelenergy.com/home-wiring-rebate-nm (website) *(illustration of a program that combines incentives for electrification with a requirement to participate in managed charging programs)*
- E3, 2023, *Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California*, ethree.com/wp-content/uploads/2023/12/E3_Benefit-Cost-Analysis-of-Targeted-Electrification-and-Gas-Decommissioning-in-California.pdf *(background on electrification and gas decommissioning)*
  - » Executive Summary, pp. 9-12 (PDF pp. 10-13)

Additional references

- Cadeo, 2022, *Memo to Portland General Electric*. assets.ctfassets.net/416ywc1laqmd/6MfsUWuIOgijDbloGpOPlR/e0fb5b68f3375f7c995c80cb353c2e1e/PGE_Cadeo_Memo_Equity_Index_and_Community_Targeting_Assessment.pdf *(See how DER forecasting is coupled with mapping as an illustrative method for targeting that would require coordination between programs and planning teams)*
- On improving programs:
  - » RMI, *Customer-Centric Energy Transformation*, 2018, rmi.org/insight/customer-centric-energy-transformation, blog
  - » ACEEE, 2020, *Leveraging advanced metering infrastructure to save energy*, aceee.org/research-report/u2001
  - » ACEEE, 2020, *National Survey of State Policies and Practices for Energy Efficiency Program Evaluation*, aceee.org/research-report/u2009
  - » ACEEE, 2021, *Demand-Side Solutions to Winter Peaks and Constraints*, aceee.org/research-report/u2101
  - » ESIG, 2024, *Charging Ahead: Grid Planning for Vehicle Electrification*, esig.energy/grid-planning-for-vehicle-electrification
- Oncar, *Oncar Clean Fleets Partnership Program*, youtube.com/watch?v=6gKYqrMkp4E, Webinar (Utility-fleet partnership example for collecting vehicle information)
- The Mobility House, 2023, *Automated Load Management: The Technical guide for EV fleet charging*, mobilityhouse.com/usa_en/knowledge-center/whitepaper/alm-guide-fleet-charging
- Grid readiness and flexibility:
  - » Advanced Water heating Initiative and Ecotope, *Field Testing Load Shifting Pilot for Commercial Water Heating, Website and webinar available,* advancedwaterheatinginitiative.org/chpwh-project-update (Example of multifamily water heater load shifting application)

  - Guidehouse, 2020, *Guidehouse Evaluation of PGE's Multifamily Water heater Pilot Winter 2019-2020*, edocs.puc.state.or.us/efdocs/HAQ/um1827haq143510.pdf (Key findings on pp.vi, PDF pp. 8)
  - BPA CTA-2045 Water Heater Demonstration Report: bpa.gov/-/media/Aep/energy-efficiency/emerging-technologies/ET-Documents/demand-response-final-report-110918.pdf
  - New Buildings Institute, 2023, *Plug-in heat pump water heater field study findings and market commercialization recommendations: Lessons learned on the performance of 120 volt HPWHs from California-wide installations* newbuildings.org/wp-content/uploads/2023/07/PlugInHeatPumpWaterHeaterFieldStudyFindingsAndMarketCommercializationRecommendations_NBI202308.pdf
- E3, 2023a, *New E3 Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning Shows Potential for Cost Saving* ethree.com/a-new-e3-benefit-cost-analysis-of-targeted-electrification-and-gas-decommissioning-shows-potential-for-cost-savings
- E3, 2023b, *Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California Evaluation of 11 Candidate Sites in the San Francisco Bay Area*, ethree.com/wp-content/uploads/2023/12/E3_Benefit-Cost-Analysis-of-Targeted-Electrification-and-Gas-Decommissioning-in-California.pdf

GRID CONNECTION

OVERVIEW

Utilities may face a mismatch between the lead times required for building distribution infrastructure and the speed and scale of load growth. Costs to connect new loads or upgrade service to existing loads may be high, or potentially prohibitive, even though their impact on the distribution system is limited to a small number of hours in the year. Grid connection—the processes through which new loads or generators connect to the distribution system or through which existing loads or generators expand service through service upgrades—provides an important opportunity to efficiently manage load growth and allow faster connection timelines that align with the expected pace of electrification of transportation, building heating, and other end uses that have traditionally been met with direct onsite fuel use.

There are multiple strategies for reducing grid connection timelines and costs. Larger loads that want faster interconnection times or wish to avoid paying for distribution upgrades may be able to do so through static or dynamic flexible interconnection.[14] Hosting capacity maps for loads can help to guide prospective loads to parts of the distribution system with available capacity. Capacity reservation programs may help to ensure that customers wishing to pay for additional capacity to avoid connection delays are able to do so. Grid readiness standards, such as make-ready requirements that prepare the utility side of the meter for new connections, or integrating load flexibility / grid-connectivity into new customer equipment on the customer side that enable their participation in demand-side management (DSM) programs, do not fit neatly into traditional grid connection processes but can help bring on new load faster and more efficiently.[15] Temporary solutions, such as transformer and other equipment reserves or portable batteries, can also help to reduce connection delays in areas with high load growth.

Utilities generally have more latitude to make internal process design decisions for load connections than for their generation interconnection process counterparts. Elements such as application processing timelines, screening criteria, application modification handling, and queue management are less likely to be formally codified within tariffs or state interconnection rules. Even for those that do have more formal requirements within the load connection process, it is typically separate from generator interconnection. However, there may be efficiencies from creating a single connection process for larger loads and generators. For instance, customers may wish to combine new load, distributed generation (DG), and distributed storage (DS) in a single interconnection request. Combining load and generator interconnection requests in a single process may also enable more right-sized network upgrades and fairer allocation of upgrade costs.

14 The terms 'static' and 'dynamic' are not well-defined for flexible interconnection. Static typically refers to fixed MW (or MVA) limits that do not vary over time. Dynamic typically refers to limits that can vary over time, even if these limits are fixed far in advance. In reality, as discussed later, dynamic limits are a continuum. For our purposes, the most important point on this continuum is where utilities must more actively identify operating limits and communicate these to aggregators or customers.

15 At the convening, we discussed utility-side grid-readiness within the grid connection workstream and customer-side equipment grid-readiness within the scope of the targeted deployment workstream.

This chapter is organized into the following main sections:

- **Challenges and emerging practices**
- **Least-regrets solutions (LRS)**
- **Longer-term solutions (LTS)**
- **Data requirements**
- **Reading list**

The first three sections contain material from the Briefing Document, which attendees received prior to the convening, and summarizes the convening discussions of the grid connection group. The data requirements section synthesizes how data sharing was discussed by the grid connection group. The reading list section is background reading that was provided to participants in the Briefing Document.

CHALLENGES AND EMERGING PRACTICES – BRIEFING DOCUMENT

For ease of reading, we have identified practices and challenges with labels throughout this section.

- Current analytical approaches in interconnection studies are conservative and often result in an underestimation of actual available capacity. ***(Challenge)***
- Migrating from nameplate capacity assumptions to less conservative demand factors and time-based load profiles in equipment sizing calculations and interconnection studies could significantly improve capacity availability across multiple layers of utility infrastructure. ***(Practice)***
- Predicting the expected energy use of new large load additions with limited historical data (e.g., for EV charging hubs) is difficult and relies initially on potentially inaccurate assumptions. Determining revenue offsets and expected construction cost contributions for these new loads will be challenging. ***(Challenge)***
- Partnerships with vehicle manufacturers, fossil-based fleet managers, cities and other organizations may give visibility into what their forthcoming electric fleet behavior may be. As an example, Eversource has partnered with OEMs to collect vehicle behavior data in anticipation of forthcoming electrification. ***(Practice)***
- Traditional interconnection processes, which are conservative, raise a myriad of challenges—they can result in high grid upgrade costs that could have otherwise been avoided with some limit on the import or export to the grid. The distribution of these upgrade costs raise cost allocation challenges. ***(Challenge)***
- Flexible interconnection sets limits on withdrawals (loads) or injections (generation) to allow customers to expedite interconnection and potentially avoid network upgrade costs. ***(Practice)***

- It can be categorized in terms of the flexibility of operating limits (static or dynamic) and which entity controls the load or generator (customer/aggregator or utility); static limits will generally be customer controlled, with relays or other protective equipment to ensure that the limit is not exceeded. ***(Practice)***
- In all of these different cases, control and enforcement requirements are generally part of interconnection rules and technical standards. ***(Practice)***
- A number of jurisdictions have implemented rules allowing DG customers to interconnect with export limits (static interconnection); dynamic interconnection limits for DG are still in the pilot stage in the U.S., but have been implemented in the UK and Australia. ***(Practice)***
- Utilities are beginning to apply flexible interconnection concepts to EV fleet charging, though with limited exceptions these are also in the pilot stage. ***(Practice)***

The table below describes examples of flexible interconnection implementation or pilots, both for loads and DG.

CATEGORY	UTILITY OR JURISDICTION	PROGRAM	DESCRIPTION
Load **Static, customer control**	California utilities, ComEd, Ameren	Automated Load Management (ALM), EV Energy Management System (EMS)[16]	Customers install certified ALM technologies; CA's default position is to rely on EV operator hardware/ software (EV Energy Management Systems); ComEd and Ameren are piloting capability in 2024.
Load **Dynamic, utility control**	National Grid	Flexible EV Connections	Allow EV fleet operators to connect in advance of distribution upgrades; use DERMS to actively control loads, building on National Grid demonstration for DG; National Grid plans to pilot for first 5 years, then scale during second 5 years of its 10-year grid modernization plan (2023)[17]
Generation **Static, customer control**	California, Hawaii, Nvevada, and others	Static import/export limited Interconnections	Allows customers to interconnect one or more resource types under a control scheme that enforces site-wide constraints, rather than assuming the full nameplate impact of each individual resource for interconnection study purposes
Generation **Dynamic, customer control**	California Utilities and Eversource	Limited Generation Profiles (LGPs)	LGPs establish different 24 hour profiles for each month that allow greater nameplate capacity and exports of solar and storage of any size; use new UL standard (under development) to enable smart scheduling for smart inverters. CPUC has issued a draft order with a final order expected March 2023.[18] Eversource Massachusetts has proposed 24-hour (and seasonal) profiles for storage.[19]
	National Grid	Export Limitation Scheme/Local Power Export Control	Allow customers adding DG BTM to an existing load profile to locally manage operational profile to negate thermal impacts and mitigate upgrades. National Grid plans to scale by 2026.[20]

16 innovate.comed.com/bepilots/ev-ems

17 fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18552718, at 347

18 CPUC Draft Resolution E-5296, at 56. docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=523916569.

19 fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18159721

20 fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18552718, at 265.

CATEGORY	UTILITY OR JURISDICTION	PROGRAM	DESCRIPTION
Generation **Dynamic, utility control**	National Grid MA, Avangrid NY, ComEd, Eversource MA	Flexible Solar and Storage Connections	Allow both solar and standalone storage installations to connect in advance of distribution upgrades; use DERMS to actively control resources; National Grid is currently piloting and plans to scale by 2027[21] Avangrid piloted in 2021 with plans to scale by 2025.[22] ComEd piloted[23] in 2023 and plans to scale in 2025. Eversource plans to pilot in 2025 and scale by 2029.

- Utilities in several jurisdictions have developed hosting capacity maps for loads to help guide the location of larger charging infrastructure. ***(Practice)***
- Examples of utilities with EV hosting capacity maps include Dominion, FirstEnergy, the New York utilities,[24] PSEG, and Xcel Energy (tabular format only).[25]
- Hosting capacity maps may have different data visualization tools (maps, tabular views), may only have static or may have time-varying information, and may be updated on different schedules (monthly, annual, longer than annual). ***(Practice)***
- These maps are still evolving, as utilities develop a better sense of the kinds and timeliness of information that customers need. ***(Challenge)***
- Even with flexible interconnection and hosting capacity maps, EV fleets and other customers may be willing to pay to reserve capacity on the distribution system over multiple years, for instance to facilitate long-term business planning. ***(Practice)***
- Hawaiian Electric Company, for example, is applying for approval for a pilot program in which customers could reserve distribution capacity for up to five years.
- Some jurisdictions are directing utilities to build out EV infrastructure in advance of interconnection requests. ***(Practice)***
- For instance, California's legislation (AB 841) mandates make-ready infrastructure that provides "necessary electrical infrastructure on the utility side of the meter at no-cost to the customer at typical sites"[26]; while this may accelerate the process of connecting new EV load, it raises questions about costs and cost allocation. ***(Practice and Challenge)***
- Given uncertainty in the timing and magnitude of electrification-related load growth, some utilities are exploring innovative ways to adaptively accommodate new EV load (e.g., through temporarily siting storage to address short-term capacity needs and then moving it to a new location as needs shift or through creating transformer reserves). ***(Practice)***
- For example, anticipating large needs for medium and heavy duty vehicles, Southern California Edison is planning to use movable storage (37 1 MW/4 MWh batteries over the next five years) as a short-term solution to facilitate a timely customer interconnection while a permanent solution is being constructed.[27] ***(Practice and Challenge)***

21 fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18552718, at 346.

22 dps.ny.gov/system/files/documents/2022/11/avangrid-flexible-interconnection.pdf

23 energycentral.com/c/iu/enabling-ders-and-more-comed%E2%80%99s-practice-derms-implementation

24 See, for instance, gis.cenhud.com/gisserver/rest/services/Public/HostingCapacity_Stage_3/MapServer.

25 mn.my.xcelenergy.com/s/renewable/developers/interconnection/hosting-capacity-map

26 California Assembly Bill 841, https://ww2.arb.ca.gov/2020-assembly-bill-841-ting-philip-electric-vehicle-infrastructure-training-program-and-energy and see NRDC, 2020, https://www.nrdc.org/bio/merrian-borgeson/newsom-signs-law-clean-air-inside-and-out-school

27 ESIG, 2024, Charging Ahead: Grid Planning for Vehicle Electrification, https://www.esig.energy/grid-planning-for-vehicle-electrification/

- In addition to measures aimed at reducing interconnection costs, some jurisdictions have undertaken reforms of cost allocation for network upgrades triggered through interconnection.
- Examples include New York's Cost Sharing 2.0 mechanism, Massachusetts' Capital Investment Project Fee, and Maryland's Cost Allocation Mechanism.
- These mechanisms differ in terms of their scope (which kinds of investments are included), whether they are for triggered or proactive investments (or both), whether there is a process for considering cost allocation for multi-value investments (e.g., for assets that will be replaced, only charging incremental cost to interconnecting customers), and how risks to ratepayers are mitigated (e.g., balancing accounts and spending caps).
- Although these reforms have focused on DG interconnection, there are likely parallels with load connection.

CHALLENGES AND EMERGING PRACTICES – CONVENING DISCUSSION

The group first discussed challenges, including and building on those in the Briefing Document. The following table was used to center the discussion around five primary categories of challenges: processes, data and analysis, technology and standards, cost allocation, and flexible interconnection. The group differentiated between primary challenges (shaded cells), which are the main challenge category that challenges map on to, and non-primary challenges (the O's), which are related but are not primary challenges.

	CHALLENGE CATEGORY				
CHALLENGE	**PROCESSES**	**DATA + ANALYSIS**	**TECH + STANDARDS**	**COST ALLOCATION**	**FLEXIBLE I/C**
Limited historical data	O	O		O	
Lack of formal load connection processes	O				
Limited experience with hosting capacity for loads	O	O			
Flexible interconnection for loads remains nascent			O		O
Uncertainty in EV load growth, usage patterns			O		

Note: Shaded cells indicate primary challenge type

The group discussed several of these and other challenges in more detail. Themes in this discussion included:

- **Aligning load connection and DG/DS interconnection processes.** Keeping these processes separate can be its own challenge. Cost allocation could be better handled if loads and resources in these processes are considered together.
- **Load characteristics and load growth uncertainty.** There are multiple sources of load growth, including, new manufacturing facilities, EVs, building electrification, and increasing automation in warehouses. Each of these loads has different needs from the distribution

system (e.g., timing and size of connection), different options and flexibility for grid connection. Furthermore, the "how" of engineering the grid for meeting new load (e.g., design rules of thumb) varies significantly for different kinds of load. The group agreed that it will not be cost-effective to handle or plan for grid connections one at a time and in isolation. Communication within large utilities on this topic is limited.

- **Load growth visibility.** Larger load additions that do not trigger service upgrades or notification to the utility (e.g., home level 2 EV chargers) can be challenging in the aggregate.
- **Problem solving versus regulatory compliance.** Regulatory requirements can risk putting utilities in a "compliance mindset" regarding grid connections, rather than focusing on problem solving and desirable outcomes.
- **Grid connection and distribution planning.** Grid connection must impact distribution system planning processes, so that the larger picture and expectations of overall load growth can drive changes in the distribution system in the aggregate.

LEAST-REGRETS SOLUTIONS – BRIEFING DOCUMENT

Recap of core challenges

- Due to the lack of historical data and other complications, grid connection analysis is challenging (demand factors, charging profiles, and annual energy usage estimation are uncertain).
- Many utilities do not yet have formal load connection processes.
- Utilities and customers still have limited experience with hosting capacity maps for loads.
- Flexible interconnection for loads has yet to be implemented on a larger scale.
- Utilities may need adaptive tools to address EV load growth uncertainty and changes to patterns of EV use.

Potential least-regrets solutions

Least-regrets solutions for grid connections are intended to provide utilities with a foundation for using the grid connection process to manage load growth more efficiently and cost effectively.

Potential least-regrets grid connection solutions

(Entities responsible for implementation are in parentheses)

1	Reviewing transformer sizing calculations and subdivision design calculations and standards to incorporate electrification impacts (utilities)
2	Building and refining data-driven methods for determining demand factor, load profile, and energy usage for use in equipment sizing and connection study processes (utilities, stakeholders)
3	Exploring the changes (if any) needed for more formal load connection processes (utilities, commissions, stakeholders)
4	Enabling static interconnection limits for larger customers (utilities, commissions)
5	Exploring the benefits and costs of hosting capacity maps for loads (larger utilities, commissions)

6	Assessing the adequacy of current grid readiness standards and propose new standards or harmonization of existing standards, if needed (utilities, stakeholders)
7	Establishing early engagement between fleet owners, municipalities, and utilities to increase visibility of upcoming needs before the formal connection request (fleet owners, municipalities, utilities)[28]
8	Reviewing methods for connection cost allocation to ensure they are robust to electrification-driven load growth (utilities, commissions)

LEAST-REGRETS SOLUTIONS – CONVENING DISCUSSION

Overall discussion

The group began the least-regrets solutions (LRS) discussion by exploring what might constitute "least-regrets" in the context of grid connection. Participants noted that, for some solutions, implementation might seem straightforward, but the straightforward approach would not lead to meaningful outcomes—for instance, a utility might implement a new grid connection process, but it might not work that well. Other solutions that appear to be least-regrets might require regulatory changes to implement, or may be relatively easy to do but utilities and other stakeholders lack incentives to implement them. Alternatively, too much regulation for LRS risks putting utilities in a compliance mindset without focusing on outcomes; in some jurisdictions (e.g., Hawaii), utilities have already had to innovate beyond what was being regulated. These considerations aside, the group agreed that there are elegant, implementation-ready LRS for grid connection, focused on outcomes, that would have broad benefits for distribution grid connection processes across the U.S.

Prioritization

Building on this discussion, the group modified the LRS in the Briefing Document and discussed them within the framework of the same five categories outlined above for types of challenges (see table below; primary challenges are shaded). The group noted that static flexible interconnection can be valuable for smaller (e.g., individual residential) customers and is not just limited to large loads. Transparent load connection processes do not necessarily need to be "formal," in the sense of being specifically prescribed and enshrined within administrative codes and tariffs. Rather, existing utility processes could be modified to adapt to changing customer needs. The group added an LRS around streamlining rules for load connection, similar to what has been done for DG (e.g., standard options customers and developers can choose from, such as flexible or standard interconnection and "fast-track" processes for applicants meeting certain conditions), but determined it could be added under the load connection processes LRS.

28 As discussed in the ESIG EV paper and here: North American Council for Freight Efficiency has recommended early engagement between fleets and utilities to increase understanding of fleets' charging needs (NACFE, n.d.; 2022)

	LEAST-REGRETS SOLUTION	PROCESSES	DATA + ANALYSIS	TECH + STANDARDS	COST ALLOCATION	FLEXIBLE I/C
1	Sizing calculations	○	○		○	
2	Performance and utilization assumptions		○		○	
3	Load connection processes	○				
4	Static interconnection limits	○	○	○	○	○
5	Hosting capacity maps	○	○			
6	Grid readiness standards			○		
7	Early engagement	○	○			
8	Connection cost allocation methods				○	

Note: Shaded cells indicate primary challenge type.

There was general consensus among the group that LRS can be most effective in the near term if they require little to no regulatory changes or approvals. These are likely to be the low-hanging fruit opportunities. Some opportunities to achieve timeliness and affordability goals for load connection may not even require utility action—for example, power control system technologies used for static flexible interconnection can also be used during customer load additions to prevent the need for service equipment upgrades and panel replacements—though utilities may still need to be kept in the loop.

Based on impact and feasibility, the group prioritized LRS and voted on three LRS to further explore: (1) sizing calculations, (2), static flexible interconnection, and (3) streamlined load connection processes. The group determined that considerations around cost allocation, while critical, should be addressed primarily through longer-term solutions due to complexity and the likely need for more fundamental regulatory changes. The group also determined that grid readiness standards should be a long-term solution rather than an LRS.

For each of the three priority LRS areas, the group explored relevant stakeholders, data requirements, technologies, and standards. The group then examined how each LRS could be implemented and scaled, what case studies might be relevant to draw from, what the risks might be, and which issues should be "parked" for later consideration ("bike rack").

Detailed discussion on prioritized least-regrets solutions

Sizing calculations

The group developed three main activities for the sizing calculations LRS:

- Refine data-driven methods for determining demand factor, load profile, and energy usage for use in equipment sizing and connection study processes.

- Refine and update utility calculation tools and strategies for designing and sizing service transformers, subdivisions, and building infrastructure.
- Encourage cooperation and data sharing across utilities and from industry stakeholders with load profile information (e.g., OEMs).

The group identified stakeholders, data requirements, technologies, and standards that would be relevant to these three activities. Ideally, these three activities could be implemented using existing standards and best practices.

STAKEHOLDERS	DATA REQUIREMENTS	TECHNOLOGIES	STANDARDS
• Utilities • Authorities having jurisdiction (AHJs) / municipalities • Commissions and staff • Standards bodies • Mass-market electricians / contractors • Real estate developers • State energy offices (for building code development)	• Grid topology • Distribution equipment types, configurations, specifications • Load assumptions (what granularity?) • Building modeling assumptions • Project details and assumptions • Diversity factors • Rates and rate options • Solution characteristics • System assumptions (losses, loading, etc.)	• AMI • Power flow modeling • Utility asset management modeling • Distribution hardware • Alternative solutions (e.g., energy storage, smart panels) • Workflow automation (internal utility function)	• National Electrical Code (design) • North American Electric Reliability Corporation (NERC) standards (reliability) • Commission standards and rules (tariffs) • Institute of Electrical and Electronics Engineers standards (design and certification)

The group identified several potential activities for different stakeholders to implement the sizing calculations LRS, including a best practices manual, local or municipal outreach to contractors and developers, model tariffs (where relevant), and a standards gap analysis. These activities could be scaled through capacity building with peers (Edison Electric Institute, National Rural Electric Cooperative Association, Electric Power Research Institute, American Public Power Association, national labs), a commission-led collaborative and sharing across commissions (e.g., through NARUC), an education "playbook," and stakeholder engagement and collaboration. Case studies might include service transformer loading studies and studies that segment end-use load profiles.

The group identified several potential risks for the sizing calculations LRS, including supply chain issues, utility resource constraints, skepticism of new technology, resistance to (perceived) complexity, peer engagement from third parties, labor relations, data availability and integrity, and opposition from gas utilities. Incrementalism may be a useful strategy for avoiding resistance to change. The group parked three issues on the bike rack: line extension allowances, cost allocation, and new codes and standards development.

The group identified several potential activities for different stakeholders to implement the sizing calculations LRS.

STAKEHOLDERS	ACTIVITIES FOR IMPLEMENTING SIZING CALCULATIONS LRS
Utilities	• Share assumptions across organization • Update assumptions and tools (and conduct research to support updates) • Share / collaborate on best practices across peer utilities • Have dialogue with developers on standardized, quick calculation processes
Utility Commissions	• Motivate and facilitate
Technology providers, OEMs, customers, developers	• Share information with utilities
Standards organizations	• Model and best practices development
Mass market electricians, contractors, State Energy Offices	• Proactive engagement with utilities on design standards • Best practices development • Building code, NEC capacity building (with AHJs, municipalities, state energy offices)

Static flexible interconnection limits

As identified previously, static flexible interconnection refers to the use of customer management strategies and technologies to reduce the overall impact of the resources on the system (relative to full nameplate operating capabilities) and/or streamline the grid connection process. One common example of static flexible interconnection is the use of power control systems to limit import/export through the utility meter or through a customer's circuit or service main breaker.

The group developed four main activities for the static flexible interconnection limits LRS:

- Develop and implement load connection option(s) which are based on flexible interconnection limits, rather than nameplate capacity, enabling faster, less expensive (inter) connections by avoiding distribution upgrades and/or customer site equipment upgrades.
- Encourage industry understanding, evaluation, and adoption of flexible options.
- Capture utility process impacts and identify necessary modifications.
- De-risk adoption by building confidence in technology/standards without requiring costly relays.

The group identified stakeholders, data requirements, technologies (customer and utility), and standards that would be relevant to these four activities.

STAKEHOLDERS	DATA REQUIREMENTS	TECHNOLOGIES	STANDARDS
• Utilities • Developers and customers • Vendors • Regulators • Standards organizations	• Project data (e.g., operating profiles, connected equipment) • Utility system data • Rules and procedures (distribution engineering, design standards)	*Customer* • Power control systems (PCS) • Telemetry • EVSE controls *Utility* • Distribution controls (ADMS, DG rules, DERMs) • Telemetry (field area networks, cellular, etc.) • Imports, relays	• IEEE 1547 • UL 1741 / UL 1741-CRD (PCS) • Thermal ratings • Customer end-use standards • Communications standards

The group identified interconnection rules (DG + load) and load-only connection processes as entry points for implementing flexible interconnection, with the latter likely being easier than the former due to the additional complexities that can accompany DG. Implementation would depend on equipment availability and customer awareness and would require changes in utility internal standards of practice, guidance on best practices and use cases, learning and iteration, and stakeholder buy-in. Case studies could include experience from the United Kingdom or IREC model procedures.

Several risks could hinder progress on the static flexible interconnection limits LRS, including institutional inertia, misaligned expectations, and enforcement and performance issues. The group placed several issues on the bike rack: distribution planning and capacity availability, hosting capacity, differential customer requirements for reliability, and under-frequency load shedding.

The group identified several potential activities for different stakeholders to implement the static flexible interconnection limits LRS.

STAKEHOLDERS	ACTIVITIES FOR IMPLEMENTING STATIC FLEXIBLE INTERCONNECTION LIMITS LRS
Utilities	• Update load addition study process • Develop flexible load agreement • Develop/publish standards for customer compliance • Change management and intra-utility awareness of new procedures and capabilities • Risk management
Developers and customers	• Commission and submit projects • Submit compliant site plan and application materials • Raise awareness of flexible interconnection process and options • Assess feasibility and economics of flexible interconnection as a solution • Adapt operating procedures to meet flexible interconnection requirements
Vendors	• Comply with standards • Develop solutions for flexible interconnection
Regulators	• Motivate and facilitate • Performance incentives
Standards organizations	• Update standards (as needed)

Streamlined load connection processes

The group developed five main activities for the streamlined load connection process LRS:

- Develop more transparent and externally accessible load connection processes.
- Ensure these processes are streamlined to reduce connection times; are transparent with required information and timing; and limit unnecessary back-and-forth between customers and utilities.
- Improve customer self-service for application submission, status checking, and disconnect/reconnect requests.
- Enable and inform customers, AHJs, and electricians of options to minimize panel upgrades (UL PCS, smart panels, etc.).
- Develop fast-track screens to reduce process burdens where practical.

The group identified stakeholders, data requirements, technologies, and standards that would be relevant to these five activities.

STAKEHOLDERS	DATA REQUIREMENTS	TECHNOLOGIES	STANDARDS
• Utilities play key role as owner of process • Commissions will need to be involved if there are cost allocation decisions to be made • Customer connection process will depend upon characteristics (residential vs. commercial; fixed vs. flexible location) • Customer, environmental, and energy justice advocates	• Telemetry, AMI, monitoring • Load shape data • Hosting capacity data • Data to enable fast-tracking of some applications	• Smart panels, smart inverters and chargers • Vehicle-to-grid capabilities • Automated load management (ALM) • Advanced load/power flow modeling software	• NEC 2023 (current limiting); UL power control system (capacity scheduling, current limiting) • Open ADR; IEEE 2030.5

Implementation of the streamlined load interconnection process LRS could include:

- Online applications for both load and generation
- Developing appropriate coordination software, including process automation and visualization
- Screening processes to expedite timelines
- Developing a single interconnection process for load and generation that does not require increased service size
- Enabling panel replacements without service upgrades
- Making a distinction between service upgrades and projects not requiring upgrades; for the latter, allowing developer disconnection with notification to the utility
- Appropriate use of performance-based incentives

As with flexible interconnection, the group agreed that streamlining load-only connection processes would be easier than streamlining processes for DG, or load and DG. Improvements in load connection could be voluntary at willing utilities, avoiding the slowness of the regulatory process. Examples and case studies to draw on might include OnCor Texas (disconnection notification)[29] and Consolidated Edison's "excellence-based" earnings adjustment mechanism (EAM).[30]

Risks for implementing streamlined load connection processes included the general issue of notification/non-notification of the utility and potential issues arising as electrification scales, legacy load assumptions and transformer loading, and potential issues with ISO interconnection processes. The group put the notion of a "first ready, first served" approach for processing applications in the bike rack.

The group identified several potential activities for different stakeholders to implement the streamlined load interconnection process LRS.

29 oncor.com/content/dam/oncorwww/documents/new-construction/construction-guidelines/Electric%20Service%20Guidelines%20Book.pdf.coredownload.pdf

30 EAM is the term used in New York for performance incentives mechanisms (PIMs).

STAKEHOLDERS	ACTIVITIES FOR IMPLEMENTING STREAMLINED LOAD INTERCONNECTION PROCESS LRS
Utilities	• Develop pre-screening criteria (akin to "TSA pre-check") • Develop or deploy end-to-end application self-management (akin to "TurboTax") • Collaborate on best practices across utilities and developers • Provide multiple options for connections • Provide technical support for EJ groups • Develop alternatives to "first-in, first-out" (while considering equity implications) [with commissions]
Commissions	• Define desirable outcomes, with stakeholder input • Develop performance incentive mechanism framework, based on desired outcomes, if deemed suitable as part of implementing the LRS
AHJs and municipalities	• Coordinate closely with utilities and developers / customers
Customers and developers	• Approach utility early • Provide compliant and complete applications
Technology providers	• Develop end-to-end application management portal

LONGER-TERM SOLUTIONS – BRIEFING DOCUMENT

Open questions and longer-term solutions

All of the themes discussed above—grid connection studies and processes, flexible interconnection, hosting capacity maps, connection cost allocation, grid readiness, integrated interconnection processes, and capacity reservation—have open questions about how they should evolve in the nearer and longer term. These open questions include:

Interconnection process and analysis for new load

- What demand factors, diversity factors, and load profiles should be used for electrification load additions during equipment sizing and connection studies?
- How do demand factors, diversity factors, and load profiles vary across different locations, geographies, rate and incentive structures, management capabilities, or other factors?
- How will service transformer overloads be identified, prevented, or otherwise addressed if customer load additions are not communicated to the utility?
- For locations adding multiple resource types (e.g., solar PV and EV charging), how will the separate and collective impacts be evaluated?
- How can interconnection studies be better coordinated with planning?

Flexible interconnection

- Should utilities be required to offer flexible interconnection to loads? Both static and dynamic or just static?
- What infrastructure (monitoring, communications, control) is required for utilities to offer static flexible interconnection and how are the costs recovered? What additional capabilities and infrastructure is needed to move towards dynamic flexible interconnection and at what point is it appropriate to move from static to dynamic flexible interconnection?

- Are there multiple designs to flexible interconnection, or will utilities converge on a single design? What are likely designs?
- What is the role of aggregators in implementing flexible interconnection programs?
- Can the infrastructure and processes to support flexible generator interconnection be used for flexible load connection?
- Is it worth offering dynamic flexible interconnection for smaller loads when they trigger system upgrades?
- What is the role of DERMS in facilitating flexible interconnection and/or providing other services to enable reliable integration of more electrified load? Is voltage management/optimization a starting point for DERMS? What can be achieved without DERMS and with ADMS or other grid modernization investments?
- What impacts to other processes should be considered when evaluating flexible interconnection opportunities (e.g., capacity planning, operations)?

Hosting capacity maps

- What core functionality should hosting capacity maps for electrification have? Should utilities have separate maps for different kinds of customers (e.g., EV maps) or should they have a single map for all customers?
- How detailed (spatially, temporally) do hosting capacity tools need to be? How often should they be updated?

Interconnection cost allocation

- Do interconnection cost allocation frameworks for larger loads need to change, given the potential for larger loads to use up available headroom in parts of the distribution system?
- How can the new connection study process for loads be better coordinated with asset replacement and planning, so that affected customers only pay for incremental upgrade costs?
- To the extent proactive capacity investments are made for facilitating large loads, what solutions may help address equity challenges associated with these investments if the costs will be recovered from all customers?

Grid readiness

- What grid readiness standards exist, such as “make-ready” approaches for facilitating new EV load connection? How should such approaches be implemented in fair and equitable ways?
- Should utilities and regulators take a view on interconnection and communication standards, and on emphasizing management by the charger or the car to facilitate more rapid and compatible adoption of IT for managed charging? (Challenge)

Integrating processes

- What is the value of integrating load/generation interconnection? What analysis is needed to do so (e.g., cluster studies) and what is the process? Is it worth the effort?

Capacity reservation

- What are the merits and challenges of capacity reservations, as a strategy to deal with anticipated load growth?

Roadmapping and implementation

- What avenues should be utilized to propose solutions, develop consensus, and determine the preferred path forward within a jurisdiction?
- What factors should be considered when evaluating a range of potential solutions?
- How will necessary changes to policy, tariffs, interconnection rules, or other codified requirements be incorporated within the process and timeline?

LONGER-TERM SOLUTIONS – CONVENING DISCUSSION

Overall discussion and prioritization

The group first brainstormed a list of potential LTS to discuss, drawing on the Briefing Document, and then voted to narrow this down to two LTS to explore in more detail. The full list of LTS included:

- **Dynamic, flexible, hybrid (inter)connection (within the top 2 LTS)**
- Capacity reservation
- Hosting capacity
- Early and enhanced engagement with customers
- **Cost allocation / obligation to serve (within the top 2 LTS)**
- Scaling without process failure
- Grid readiness

Among these, the group selected two priority LTS – (1) dynamic flexible interconnection and hybrid interconnection and (2) cost allocation / obligation to serve (in bold) to further explore. For these, the group defined the problem, discussed and proposed possible approaches to resolve them and identified relevant stakeholders.

Detailed discussion on prioritized LTS

Cost allocation / obligation to serve

PROBLEM DEFINITION	PROPOSED APPROACH	STAKEHOLDERS
• Need to better define "obligation to serve" • Cost causation principle may be insufficient • How broad vs. narrow to define "public goods?" • Important cost-sharing issues in current cost-sharing practices	• Evaluate differences in cost allocation practices between (a) load & generation, (b) electricity & gas, (c) technologies (e.g., EVSE vs. PV), (d) customer class, (e) location • Put forth white paper with framework for thinking about this issue • Convene discussion of regulators / policy makers to work through framework	• Regulators • NARUC / EEI • Thought leaders • Utilities • State energy offices

Dynamic, flexible, hybrid (inter)connection

PROBLEM DEFINITION	PROPOSED APPROACH	STAKEHOLDERS
• Flex interconnection studies require new study capabilities, methods, and time-series data • Flex interconnection complicates traditional queue-based interconnection rules and processing, including cost allocation • Method to allocate capacity across multiple flexibly interconnection loads must be selected, each have their own potential issues • Availability of approved / certified power control systems that can communicate via utility protocols • Information provided to applicants around expected curtailment is key to economic decision-making – what guarantees that the estimate is realistic?	• Advanced planning studies to incorporate optimization and priorities alongside time series studies • Combination of flexible interconnection and cost sharing techniques to improve cost allocation • Expanded development of communication capabilities of power control systems to facilitate interoperability • Developing method to determine when system upgrades become economic and how costs are allocated	• Utilities • PUCs • OEMs • Developers • Trade organizations • Customer/environmental advocates

DATA REQUIREMENTS

For grid connection more broadly, the group identified four categories of data needs and flows – intra-utility, utility-to-external, both intra-utility and utility-to-external, and external-to-utility.

INTRA-UTILITY	UTILITY-TO-EXTERNAL	BOTH INTRA-UTILITY AND UTILITY-TO-EXTERNAL	EXTERNAL-TO-UTILITY
• Resource characterization and planning assumptions – what assumptions are used for different technologies and resources?	• Utility standards – what are the requirements and standards for a customer's proposed connection?	• Customer data (e.g., billing, service level) • Grid topology at a resolution useful for internal/ external planning • Rate options • Grid conditions (e.g., capacity availability	• Project data • Resource characterization and planning assumptions – what assumptions are used for different technologies and resources? • Load shapes anticipated from new resources • Load addition notification without service upgrade

READING LIST

Pre-workshop suggested reading

- EPRI, 2018, *Understanding Flexible Interconnection*, epri.com/research/products/000000003002014475, pp. 2-8
- National Grid UK, *Flexible Interconnection Options*, nationalgrid.co.uk/downloads-view-reciteme/540250, p. 1

- Avangrid, 2022, *Flexible Interconnection: REV Demo Lessons Learned and Scalability Roadmap*, psegliny.com/aboutpseglongisland/ratesandtariffs/sgip/-/media/24A59A6BE07E47F7A3BFB97DAC3AE7AE.ashx, pp. 3-9
- SEPA, 2023, *Providing EV Load Capacity Maps: A Case Study with Dominion Energy*, s3.us-east-1.amazonaws.com/fonteva-customer-media/00Do0000000Yi66EAC/NlOPxxST_Case_Study_Providing_EV_Load_Capacity_Maps_pdf, pp. 3-5

Additional references

- ESIG, 2024, *Charging Ahead: Grid Planning for Vehicle Electrification* esig.energy/grid-planning-for-vehicle-electrification (especially "Maintaining Reliability at a Reasonable Cost" and "Coordinating Equitable Plans" sections)
- The Mobility House, 2023, *Automated Load Management: The Technical Guide for EV Fleet Charging*, mobilityhouse.com/usa_en/knowledge-center/whitepaper/alm-guide-fleet-charging
- ComEd pilot flexible interconnection for C&I EV customers, innovate.comed.com/bepilots/ev-ems
- BATRIES, 2022, *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, energystorageinterconnection.org/resources/batries-toolkit (especially Chapter III, Requirements for Limited- and Non-Export Controls, energystorageinterconnection.org/wp-content/uploads/2022/03/BATRIES-TOOLKIT-Chapter-III.pdf
- EPRI, 2018, *Understanding DERMS*, epri.com/research/products/3002013049
- SEPA, 2023, *Encyclopedia of DERMS functionalities*, sepapower.org/resource/encyclopedia-of-derms-functionalities
- IREC, 2021, *Key decisions for hosting capacity Analyse*s, irecusa.org/resources/key-decisions-for-hosting-capacity-analyses
- NARUC, 2023, *NARUC Grid Data Sharing Playbook*, pubs.naruc.org/pub/E2E50FD7-CD1B-62D5-1071-8D8362AD1E6D?_gl=1*1vdpu5j*_ga*NDc3NTk2OTQ5LjE3MDU2MDM5MTQ.*_ga_QLH1N3Q1NF*MTcwODYxODM3NC41LjEuMTcwODYxODY0Ny4wLjAuMA

DISTRIBUTION OPERATIONS

OVERVIEW

The impact of electrification on distribution system operations is unclear. If utilities rely mainly on distribution system expansion to meet load growth, few to no changes in distribution operations may be needed. But significant changes in operations may be needed to the extent utilities take steps to make more efficient use of distribution system capacity—such as dynamic flexible interconnection and dynamic demand-side management (DSM) measures that are responsive to changing grid conditions.

Changes in distribution operations to support electrification need to be considered in the larger context of multiple other drivers in addition to electrification—grid modernization and new operator capabilities; increasing levels of distributed generation (DG) or storage (DS); changes in operations needed for wholesale market coordination (FERC Order 2222 compliance); and an increased focus on resilience and dealing with the impacts of extreme weather. For instance, an advanced distribution management system (ADMS) that supports outage management systems could also provide a platform for implementing managed charging and other distribution-level DSM programs.

Across these different drivers, there are open questions as to the level of visibility and monitoring, resource and load control, and market coordination and aggregation necessary for utilities to reliably and efficiently operate distribution systems. In some jurisdictions, aggregators will play a larger role in distributed energy resource (DER) operations, which will introduce additional requirements for communication systems and information sharing (i.e., among the aggregator, DER systems, and utilities). Regardless of jurisdiction, there are several least-regrets strategies that utilities can take that would help to build a foundation for efficient distribution operations and expansion with electrification.

This chapter is organized into the following main sections:

- **Challenges and emerging practices**
- **Least-regrets solutions (LRS)**
- **Longer-term solutions (LTS)**
- **Reading list**

The first three sections contain material from the Briefing Document, which attendees received prior to the convening, and summarizes the convening discussions of the operations group. In this chapter, data requirements are discussed within the context of least-regrets and longer-term solutions. The reading list section is background reading that was provided to participants in the Briefing Document.

CHALLENGES AND EMERGING PRACTICES – BRIEFING DOCUMENT

For ease of reading, we have identified practices and challenges with labels throughout this section.

- Traditionally, distribution system operators were able to maintain reliability with minimal real-time visibility over power flow (real/reactive and direction), voltage magnitudes and phase angles, protection equipment status and operations, and transformer tap positions. ***(Practice)***
- The industry and academic literature generally assume more visibility—such as full state estimation at the distribution feeder level, or AMI data made available to distribution system operators—is needed for optimal load management. ***(Challenge)***
- The level of visibility needed by distribution operators depends, in part, on the level of active control (utilities identifying a potential violation and some entity changing injections or withdrawals to address it) versus passive regulation (e.g., smart inverter Volt-VAR curves, capacitor bank settings).
- In Hawaii, for example, which has relatively high penetration of DG, utilities have been using aggregated data at the circuit, substation, and system levels; they have had visibility into some devices but more visibility has not been needed yet. ***(Practice)***
- How far and how aggressively to move from the traditional passive toward an active, distribution system management paradigm is a strategic and philosophical question, not just a technical one. ***(Practice and Challenge)***
- Over the last decade, distribution utilities have significantly improved their visibility over distribution systems through a combination of substation SCADA investments and AMI rollouts. ***(Practice)***
- Despite improvements, many utilities still have visibility gaps and issues with the time synchronization of different measurements (e.g., SCADA data can be off by seconds or minutes, AMI data may not be available for several hours). ***(Challenge)***
- Data gathering and processing also remains a challenge for many utilities; the business models for data gathering and processing are still evolving and may involve data collection from non-traditional sources. ***(Challenge)***
- For example, in an EV-TOU rate roll out in Puerto Rico, EV charging data will be measured by vehicle/charger and aggregated by a third-party for use in LUMA's billing system. As another example, one potential model for collecting data on the secondary distribution system could be for electric utilities to buy data from telecom companies, which could install sensors on cable boxes to collect local voltage and other data. ***(Practice)***
- A growing number of utilities and coops have implemented ADMS, often with improved reliability (e.g., FLISR, OMS) as the primary driver. ***(Practice)***
- ADMS provides a platform to build future functionality, though care must be taken to ensure that modularity and interoperability are built into ADMS implementation. ***(Practice and Challenge)***
- Growth in DG and DS has not yet led to fundamental changes in distribution operations in most jurisdictions. However, with changes in standards (e.g., more active inverter controls), programs (e.g., dynamic operating limits for flexible interconnection), and markets (e.g., Order 2222 compliance), it may do so in the future. ***(Practice and Challenge)***

- More passive strategies for relieving distribution constraints—rate design, static interconnection limits—may not require any changes in distribution system operations; however, dynamic limits, managed charging, and other DSM programs to reduce electrification-driven distributions costs may require new operational capabilities.
- Changes in operations to support higher levels of DG/DS may overlap with those needed to support flexible interconnection, managed charging, and other DSM programs that support electrification. ***(Challenge)***
- To support higher levels of DG/DS, many utilities have either piloted or implemented Distributed Energy Resource Management Systems (DERMS), often focused on bulk system services, but a growing number are also considering DERMS for flexible interconnection or to enable DERs to provide distribution-level services. ***(Practice)***
- Utilities have taken two approaches to DERMS: (1) use DERMS to directly control DG/DS and loads, (2) use DERMS to communicate dispatch instructions to aggregators that directly control DG/DS and loads.

The table below shows examples of recent DERMS implementations, illustrating the use of DERMS to manage resources for distribution-level services; the diversity of utilities and use cases for DERMS, and in National Grid's case how it leveraged its DERMS pilot for DG management for flexible EV interconnection.

UTILITY (YEAR), NAME	DESCRIPTION
National Grid (2025+), Flexible EV Connections[31]	Allow EV fleet operators to connect in advance of distribution upgrades; use DERMS to actively control loads, building on National Grid demonstration for DG; National Grid plans to pilot for first 5 years, then scale during second 5 years of its 10-year grid modernization plan (2023)
National Grid MA and Eversource MA (2025+), Local grid services	Both utilities propose to leverage two different functions of DERMS to procure grid services; direct control will be focused on systems 500 kW and above while aggregator controlled will be relied upon for assets smaller than that
Snohomish PUD (2019-Present), Arlington Microgrid[32]	Snohomish PUD used a DERMS platform to communicate to the Arlington Microgrid pilot project and manage diverse DERs (DG/DS, V2G)
Saint John Energy (2018-2022), Smart Energy Project[33]	A demonstration project to manage multiple types of DERs (DG/DS, DR, EV charging) to reduce peak load
Lakeland Power Distribution, (2019-2022), SPEEDIER Grid[34]	A pilot program to control diverse DERs (DG/DS, hot water tanks, EV charging) for a rural municipality
PG&E (2016-2018), DERMS demonstration, San Jose	Evaluated use of DERMS to manage residential and commercial aggregated DER for ISO market and distribution services
PPL (2021-Present), DER Active Management Program[35]	Install a communications device (via AMI or cellular) to monitor DG inverter performance parameters and control reactive power functions (e.g., volt/var curve, power factor override) to improve power quality and system planning

31 fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18552718, at 347
32 snopud.com/wp-content/uploads/2022/06/UW_TechnoEcon_AMG_022822.pdf
33 sjenergy.com/pages/smart-grid
34 speedier.ca/wp-content/uploads/2022/12/SPEEDIER-Final-Public-Report-Rev2.1.pdf
35 puc.pa.gov/pcdocs/1775616.pdf

UTILITY (YEAR), NAME	DESCRIPTION
ComEd (2021-Present), DERMS Demonstration Pilot[36]	DERMS Pilot monitors the power flow on the substation transformer and curtails solar PV output to mitigate reverse power flow overload
National Grid MA (2023- present) **Avangrid NY (2021- present)** **ComEd (2023- present)** **Eversource MA (2025+), Flexible Solar and Storage Connections**	Allow both solar and standalone storage installations to connect in advance of distribution upgrades; use DERMS to actively control loads; National Grid is currently piloting and plans to scale by 2027;[37] Avangrid piloted in 2021 with plans to scale by 2025;[38] ComEd piloted[39] in 2023 and plans to scale in 2025; Eversource plans to pilot in 2025 and scale by 2029

- Australian utilities' implementation of dynamic operating envelopes illustrate one approach to dynamic interconnection limits: ***(Practice)***
- In this approach, dynamic limits can be set month-ahead, week-ahead, or day-ahead; limits are communicated to devices or aggregators via APIs, and the customer or aggregator controls resources (or loads) to be within limits. ***(Practice)***
- Some jurisdictions in Australia are requiring new sites to be capable of remotely updating and enacting dynamic export limits using IEEE 2030.5 and common smart inverter profile (CSIP) standards; Australia is converging on IEEE 2030.5 as a standard for communicating dynamic operating envelopes.[40]
- Implementing dynamic limits in the U.S. may require some utilities to develop new forecasting capabilities (month-ahead, week-ahead, day-ahead, hour-ahead, sub-hourly) and may require new processes to integrate load/resource forecasting and communications into operations. ***(Challenge)***
- If dynamic limits are set further out in time (e.g., using historical data or month-ahead/week-ahead forecasts), limits will need to incorporate a larger capacity buffer to address uncertainty but utilities may have lower requirements for load and resource forecasting, network monitoring, and communications with customers and aggregators. ***(Challenge)***
- The benefits and costs of different timescales for implementing dynamic limits, as well as the strengths and shortcomings of utility versus aggregator control of resources, are still unclear. ***(Challenge)***
- Distribution operator focus areas and required skillsets are changing as a result of new technologies and an increasing focus on distribution optimization and power flows.
- Historically, distribution operators have focused on safety and power restoration, with operators drawn primarily from line crew leaders, construction/operations supervisors, or other areas that interact with utility crew safety practices for energized and de-energized work.
- Modern operations often requires more engineering skills to understand power flow results, system optimization goals, and the expected impacts of utility controls to more granular resources like capacitors, regulators, and DERs. ***(Challenge)***

36 icc.illinois.gov/downloads/public/edocket/578620.PDF

37 https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18552718, at 346.

38 https://dps.ny.gov/system/files/documents/2022/11/avangrid-flexible-interconnection.pdf

39 https://energycentral.com/c/iu/enabling-ders-and-more-comed%E2%80%99s-practice-derms-implementation

40 Dynamic Operating Envelopes Outcomes Report, at 22-30. https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf

- Many jurisdictions have accepted the idea of a phased development of operational capabilities for the distribution system, which implies that it will be important to have a long-term plan for which capabilities will be needed and when, what kinds of hardware/software investments will be needed to support them, and how these investments will be justified and paid for. ***(Practice and Challenge)***

CHALLENGES AND EMERGING PRACTICES – CONVENING DISCUSSION

The group began with a discussion on challenges, emerging practices, and LRS. This discussion highlighted several points.

- The business-as-usual is unsatisfactory and/or too expensive.
- Electrification cannot be solved by just "building more wires"; distribution operations will need to evolve.
- The distribution operator experience is critical.
- Operators should not be overloaded with tasks/information, given their already complex responsibilities; regulators and stakeholders must build trust with operators and integrate their inputs into every stage of planning the evolution of distribution operations.
- The economics of foundational investments are still unclear; there is concern that the economic case for foundational investments may be weak.
- Customer experience must not be affected; new operations paradigm must not disrupt customer reliability.
- Utilities are at different stages of technological evolution.
- Different utilities are starting at different places, so it will be difficult to propose least-regret and long-term solutions and strategies that are similarly applicable to all.

LEAST-REGRETS SOLUTIONS – BRIEFING DOCUMENT

Recap of core challenges

- Determining what (and where and when) operational capabilities and investments distribution utilities should deploy (e.g., ADMS, DERMS), in a way that satisfies commission needs for prudence and limits pressure on rates.
- Determining EV and DER control strategies and the specific role of DERMS.
- Understanding incentives and disincentives for utilities to move toward more active and granular distribution system operating strategies.
- Ensuring eventual interoperability between utility investments that could support multiple operational capabilities but are being initially used for a specific need.

Potential least-regrets solutions

Least-regrets solutions for distribution operations are intended to provide a foundation for longer-term operational capabilities, regardless of the current or expected level of electrification or DG/DS, and to ensure that software and hardware designed to meet a current need could be scaled to meet other future needs (e.g., monitoring and communications systems to improve reliability could also be used to set and enforce dynamic operating limits).

Potential least-regrets operations solutions

(Entities responsible for implementation are in parentheses)

Developing longer-term plans and business cases for new capabilities, ensuring that new software and hardware can be modular/incremental and fulfilling multiple functions over time (utilities)
In the near term, focusing on fundamentals (monitoring, communications, controls) related to reliability and outage management (utilities, commissions, stakeholders)
Supporting foundational economical distribution company actions that bring greater visibility into the distribution system (such as linking AMI with SCADA and/or ADMS); these can be part of broader grid modernization efforts (utilities, commissions)
Developing a common understanding of different use cases and potential triggers related to DERMS (utilities, commissions, stakeholders)
Exploring operational requirements for using existing or planned DSM programs to provide distribution-level services

LEAST-REGRETS SOLUTIONS – CONVENING DISCUSSION

Overall discussion

The group discussed that, because of the diversity of technologies and the different starting points different utilities are at, the least-regrets solutions (LRS) from the Briefing Document may be difficult to implement across most or all utilities. In light of this, and drawing on the Briefing Document, the group developed a new list of LRS, organized around people, planning, and actions.

People – bring in the operators. Bring the operators into the conversation—both about operations but also in relation to other facets of distribution system evolution (planning, connection, rates, deployment)—to build trust and ensure a workable operator experience and develop a training plan to operate a more complex distribution system.

Plan – develop an operations investment roadmap. Identify the triggers for specific investments, build a flowchart of these triggers that can be applicable to most utilities irrespective of the different stages of technological evolution, and test and build the economic case for future investments (ADMS, DERMS, sensing equipment, etc.). Although some triggers and business cases may be generalizable, the group felt that each utility would need to develop its own investment roadmap that takes into account its current stage of technological evolution, and the triggers and business cases that are specific to its own context.

Action – prioritize foundational investments. Identify and prioritize investments that are both foundational to operations today and will address future problems as load growth due to electrification increases (e.g., GIS). The ideal "foundational investment" would not just address the problems related to electrification, but aid other grid issues such as reliability and outage management.

Detailed discussion on prioritized least-regrets solutions

The group prioritized two LRS for deeper discussion: investment roadmapping and foundational investments, both of which would include bringing in the operators (first LRS).

LRS deep dive: investment roadmap

The roadmap flow included four components:

- **Status quo assessment:** Inventory current visibility, reliability, communications, and control capabilities at the utility
- **Triggers:** Identify the triggers and threshold of triggers for upgrades and investments
- **Business case:** Identify business cases at different adoption levels
- **Right-size investments:** Ensure the investment is appropriately sized for operational efficiency and regulatory approval, and is economical and scalable

The group identified six triggers that could spur investment:

- Equipment end-of-life
- Hosting capacity limits reached
- Regulatory mandate and incentives
- Economic savings
- EV adoption
- Customer desires

LRS deep dive: foundational investments

The group prioritized foundational investments, in order from most-essential to nice-to-have.

INVESTMENT	DESCRIPTION	ACTION
Connectivity and GIS	Ensuring connectivity literally means having updated maps of how the distribution system is wired (e.g., which customers are connected to which phase); most utilities do not have detailed and fully trusted, updated system maps	Develop processes to periodically update maps of the distribution system (which customers are connected to which phase; correct location of poles and transformers).
Situational awareness	Communication infrastructure that allows the distribution control room to monitor currents and voltages at various points on the distribution system and change control settings (e.g., AMI, capacitor banks, volt-VAR or volt-watt control by inverters, protection settings) in response	Enable the operations control room to monitor currents and voltages, and change control settings of grid assets (cap banks, volt-VAR/volt-Watt inverter control, protection settings, etc.)
Sectionalization	Microprocessor-based relays that allow the control room to switch distribution system connections via two-way communications; sectionalization allows the control to reconfigure the distribution system when parts of the system fail, or to shut down smaller sections of the distribution system during emergencies – meaning fewer customers lose power	Improve reliability via microprocessor-based relays that reconfigure distribution system during faults or emergencies – fewer customers lose power
Improved forecasting	By having access to historical AMI data (not necessarily "real time") or sensors on the distribution system, the control room should be able to anticipate distribution system loads at each feeder and service transformer with "day-ahead" levels	Use historical AMI data and/or sensors on the distribution system to anticipate distribution system loads at each feeder and service transformer on a "day-ahead" basis

INVESTMENT	DESCRIPTION	ACTION
Other nice-to-haves		Voltage management, smart fuses, topology optimization

LONGER-TERM SOLUTIONS – BRIEFING DOCUMENT

Open questions and longer-term solutions

- It is difficult to separate changes in operations needed to support electrification from broader changes related to grid modernization, DG/DS, market coordination, and climate change resilience.
- However, given the broad range of open questions related to operations we'd like to focus the discussion on a few areas related to electrification:
  - » Changes in network **visibility and data collection** needed to support distribution planning and real-time operations
  - » Changes in operations needed to support **flexible interconnection** and **distribution-level DSM** programs
  - » **Intersections among operational capabilities** for electrification and those for improved reliability/resilience, DG/DS, and market coordination.
  - » **Operations data sharing** needs and approaches.
- Open questions in these areas include:

  Visibility and data collection
  - » Where do utilities lack visibility and data for better planning related to electrification, and where are there opportunities to leverage existing or planned investments to improve visibility and collect this data (e.g., combining AMI data with SCADA data)?
  - » Where can utilities make the most strategic investments related to improving visibility and data quality (e.g., time synchronous data)?
  - » How much data is enough? Can using machine learning be a more cost-effective approach to address data gaps versus more hardware/comms investments?
  - » Does the industry need to go toward distribution state estimation? If state estimation proves elusive, what level of approximation/confidence will be appropriate for different applications?
  - » Setting aside the cost of acquiring and storing data, is there ever a downside of having too much information?

  New capabilities for flexible interconnection and distribution-level DSM
  - » What new capabilities do distribution utilities need to accommodate electrification-related DSM programs and static limits for flexible interconnection for larger loads ("flexible load interconnection")?
  - » What new capabilities would they need for dynamic limits for flexible load interconnection? What are the tradeoffs in terms of the timescales for dynamic limits (months-ahead to real-time)? Under what conditions is utility direct control of loads (and generation) for enforcing dynamic limits preferable to aggregator control? How can utilities ensure that limits are enforced?

- To what extent would the capabilities needed for flexible load interconnection overlap with those needed for flexible generation interconnection?
- To what extent do different kinds of utility and aggregator control strategies need to interface with utility protection systems? What kinds of changes in protection systems might be needed to support more flexible control strategies?
- What is the role of DERMS in managing electrification-related load growth?
- How can PUCs and stakeholders better assess when DERMS might be needed and what for?
- How can existing tools be used to bridge the timescale gap between planning and operations?

Intersection between operational needs for electrification and those for other areas

- How much overlap is there between the investments and capabilities needed to support flexible interconnection and distribution-level DSM programs and those related to grid modernization, reliability/resilience, DG/DS, and market coordination?
- Are there ways in which utilities can develop capabilities needed for these different functions in ways that are modular and incremental?
- Does the future trajectory for distribution operations look different in different jurisdictions, or will approaches begin to converge at some point? In what ways is it beneficial for different jurisdictions to do things the same way?

Operations data sharing

- What kinds of operational data might aggregators need from utilities to help manage thermal and voltage limits? What kinds of operational data might utilities need from customers and aggregators? How can this data be securely shared? What cyber-vulnerabilities could be introduced by new data flow pathways?

LONGER-TERM SOLUTIONS – CONVENING DISCUSSION

Overall discussion

The group structured the LTS discussion using three load categories — (1) large loads and fleets, (2) residential EVs, and (3) building electrification — and four questions pertaining to visibility, communications, and control:

- What on the distribution system limits increasing adoption?
- What is enabled with increasing operations room control?
- What questions would we like to answer to better understand how to ease electrification and manage distribution system costs?
- What data considerations are applicable?

The table below summarizes the group's discussion for each load category and question.

QUESTION	LARGE LOADS AND FLEETS	RESIDENTIAL EVS	BUILDING ELECTRIFICATION
What on the distribution system limits increasing adoption?	• Large transformer availability • Supply chain constraints • Permitting process and timelines for new grid infrastructure • Rigid timelines for new load addition • Customer sophistication (e.g., improperly filled load letters causing delays in utility interconnection processes) • Economics of peak coincident loads • Cost of electricity	• Rates and incentives • Customers skipping the permitting process • Charging infrastructure for multi-family buildings • Rapid and unchecked residential EV adoption may be leading to negative system impacts	• Thermal limits of distribution hardware • Rapid changes in load shapes • Increased attention to distribution system reliability
What is enabled with increasing operations room control?	• Higher asset utilization factors of grid infrastructure • Curtailing and scheduling loads • Improved reliability, ability to respond to emergency situations	• More flexibility in loading calculations (for interconnection and local capacity constraints) • Extended equipment lifetimes • Better distribution planning	• Flexible loads can defer distribution system investments and accelerate electrification adoption • DERs (especially batteries) can dispatch to reduce demand during periods when the distribution grid is stressed • Generally, better price signals, which enables and incentivizes flexibility
What questions would we like to answer to better understand how to ease electrification and manage distribution system costs?	1. Can we obtain information about EV fleet load curves? 2. How do we address day-ahead forecasting of load and generation? 3. What is necessary to reduce costs for all customers? 4. How do we design systems to be as autonomous as possible, and prevent operators from being inundated with information and control requests?	1. Where is the inflection point on costs and rate of return? 2. How much more capacity is “unlocked” on the grid by enabling control? 3. What is the customer experience with control, and how do we balance comfort vs. grid health? 4. Can operations improve EV Load factors without upsetting customers? 5. How can we ensure equitable deployments and investments? 6. What granularity and latency do we need to enable full adoption? 7. How do we ID thresholds and tipping points for ROI and business models?	1. How much would the ability to better control hot water heater loads extend distribution? hardware lifetimes? 2. Is the “juice worth the squeeze”—do distribution system controls investments yield enough savings to justify their costs?

QUESTION	LARGE LOADS AND FLEETS	RESIDENTIAL EVS	BUILDING ELECTRIFICATION
Data considerations	Operations data need to be streamlined to prevent operator information-overload	The data considerations depend on what EV operations/programs operations would implement. Account data and load data would be required at a minimum but the data requirements are very different if the program is through an aggregator vs directly through individual customers.	Better understanding how ambient temperature and loading degrades feeders and transformers would be helpful—this is necessary to optimally control loads to extend distribution system hardware lifetimes.

Questions and projects

Building on the discussion, the group brainstormed a series of potential questions for LTS projects, which it narrowed down to three areas.

Traditional versus flexible operations: "Is the juice worth the squeeze?" This project would compare the benefits of flexible operations relative to traditional operations, for instance through a before-and-after comparison with utilities that have implemented new technologies, or modeling the benefits and costs of new technologies in distribution planning models.[41] Flexible operations means evolving distribution operations practices to a more flexible and bidirectional, data-driven approach, to improve utilization factor through DER orchestration and flexible interconnection. Traditional operations refers to low visibility, low real-time communications, static centralized control, lack of data, limited to no consideration of DR/DER response, and a "building more wires" approach to dealing with load growth.

Identifying GIS best practices. This project would improve the accuracy of utility GIS maps to ensure there is a high-quality "single source of truth" based on which utility infrastructure investment decisions can be made. Through discussions with utilities, the project would develop best practices guidelines for GIS systems, both on how to collect data and how to use that data for decision-making. This LTS is in contrast to the LRS on prioritizing foundational investments, which might include GIS as one of those foundational investments.

Autonomous orchestration and developing ideal load curves. This project would explore using autonomous software for real-time load and DER orchestration, and propose ideal load shapes for operation of various load categories. Autonomous orchestration would require a dedicated operations desk/sub-team to monitor the autonomous system deployed. The project could be piloted on a feeder or a group of feeders on the same substation. Key positive outcomes would include maximizing utilization factor, minimizing operator burden and complexity, enabling flexible interconnection and other non-wires solutions that defer distribution infrastructure expansion, and getting empirical data on what strategies actually work in a given setting.

41 Such as in Keen and Giraldez, Distribution capacity expansion planning: Current practice, opportunities, and decision support, National Renewable Energy Laboratory, nrel.gov/docs/fy23osti/83892.pdf

READLING LIST

Pre-workshop suggested reading

- Western Power Distribution, 2018, *Network Monitoring and Visibility*, https://www.nationalgrid.co.uk/downloads/4090/3-network-monitoring-and-visibility.pdf
  - » Background, Network Impact, pp. 2-3
  - » Short Term Mitigation and Solutions, pp. 10-11
- Avangrid, 2022, *Flexible Interconnection: REV Demo Lessons Learned and Scalability Roadmap*, https://www.psegliny.com/aboutpseglongisland/ratesandtariffs/sgip/-/media/24A59A6BE07E47F7A3BFB97DAC3AE7AE.ashx, pp. 3-9
- EPRI, 2018, Understanding DERMS, epri.com/research/products/3002013049, pp. 2-10

Additional references

- Ardani et al., 2018, *Coordinating Distributed Energy Resources for Grid Services: A Case Study of Pacific Gas and Electric*, nrel.gov/docs/fy19osti/72108.pdf
- PPL Electric, 2023, *Petition of PPL Electric Utilities Corporation for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan*, puc.pa.gov/pcdocs/1775616.pdf
- SEPA, 2023, *Encyclopedia of DERMS functionalities*, sepapower.org/resource/encyclopedia-of-derms-functionalities
- Australian Government, *On the calculation and use of dynamic operating envelopes, arena*. gov.au/knowledge-bank/on-the-calculation-and-use-of-dynamic-operating-envelopes
- Australian Government, *Dynamic operating envelopes workstream*, arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream

DATA ACCESS AND SHARING

OVERVIEW

The sixth workstream on data access and sharing is a cross-cutting one. As such, data was treated as a topic embedded in each of the individual workstreams 1 through 5, but also as a separate topic. We conceptualized data sharing in three "modes":

- Data sharing within utilities
- Data sharing with external partners and the public
- Data sharing from customers, aggregators and external actors with utilities

Unlike the other workstreams, we did not have a small group dedicated exclusively to this topic. As such, we do not have Convening report-outs for this theme reflected in this chapter—rather those are reflected in the previous workstream chapters. However, we include the material that was shared with the participants in the Briefing Document below.

DATA SHARING WITHIN UTILITIES

Many of the solutions identified in the individual workstreams require improved data sharing within utilities, potentially in ways that utilities have not been accustomed to. The table below (which is meant to be illustrative) shows potential data sharing from (rows) and to (columns) different workstream areas. Reading across the rows, the table shows the data that a workstream shares with other workstreams. Reading down the columns, the table shows the data that other workstreams share with a workstream.

	DATA SHARING TO				
DATA SHARING FROM	**GRID CONNECTION**	**PLANNING**	**RATES**	**DEPLOYMENT**	**OPERATIONS**
Grid connection		Resource/load characteristics (type, location, parameters, limits); planned upgrades	Resource/load characteristics (type, location) to support targeting	Resource/load characteristics (type, location, parameters, limits) and planned upgrades to support customer program targeting	Resource/load characteristics (type, location, parameters, limits); planned upgrades
Planning	Updated, consistent data needed for planning models		Adoption forecasts and planning results to support rate design and targeting	Adoption forecasts and planning results to support targeting	Operating needs/ limits, equipment settings, potential operating issues

	DATA SHARING TO				
DATA SHARING FROM	**GRID CONNECTION**	**PLANNING**	**RATES**	**DEPLOYMENT**	**OPERATIONS**
Rates		Rate adoption by location		Rate adoption by location	
Deployment		DSM program participation (amount, location, parameters, constraints, profiles, performance); EV make-ready program charging profiles (EV charger type, location, hourly profiles)	DSM program participation (amount, location, profiles, performance); EV make-ready program charging profiles (EV charger type, location, hourly profiles)		DSM program participation
Operations	Operational data to support inter-connection studies	Operational data (loads, voltages, equipment; settings); Updated system models (topology, reconfigurations) to support planning		Operational data (loads, voltages, equipment settings) to support program design	

The table focuses on workstreams rather than specific utility departments, which means that actual data sharing may look different in practice. For instance, an electrification department (if one exists) might collect data on, estimate, and forecast EV chargers by type and location, and share this data with a distribution planning department for developing charging profiles and forecasting loads.

In addition to the types of data that should be shared, there is an important question of how to share data within utilities. For example, should utilities create a new, independent department for aggregating, validating, and sharing data? Should a single, existing department within utilities (e.g., distribution planning) be responsible for aggregating, validating, and sharing data across other departments? Or should the data sharing relationships among utility departments be "many to many" rather than "one to many"?

UTILITY DATA SHARING WITH EXTERNAL PARTNERS AND THE PUBLIC

Aggregators, individual DERs and EV developers, stakeholders in planning proceedings, and other members of the public are increasingly requesting a range of utility data, such as data on historical and forecasted loads, hosting capacity, DER locations, DG interconnection, DSM programs, operating constraints, equipment limits, and planned investments. Sharing some of these data may raise security and privacy concerns, which suggests that state regulatory commissions and utilities will need to determine more formal data access rules. However, some data, or aggregations of that data, do not raise concerns and could be made publicly available with limited restrictions. Regulators, utilities, and stakeholders will need to discuss and determine how to create a data rich environment that balances these needs.

Data sharing for collaborative planning

Various jurisdictions have established collaborative grid planning processes that include dissemination of information. Examples include:

- **Load and DER forecasting:** The Massachusetts Grid Modernization Advisory Council (GMAC)[42] has made recommendations for utilities to share load forecast information (including inputs, assumptions, methods, results, scenarios) in a reviewable format (e.g., unlocked Excel spreadsheets).
- **Hosting capacity design:** California IOUs have provided hourly load profile data to the Interstate Renewable Energy Council (IREC) and the California Public Advocates Office so that these organizations can analyze the value of transitioning from single hosting capacity values to multiple point hosting hosting capacity values.
- **Resilience and climate risk:** Massachusetts utilities are required to develop Climate Vulnerability assessments with the GMAC recommending that the locations of substations should be mapped alongside projected sea level rise and floodplains.[43]
- **Capital investment plan transparency:** The Illinois Climate and Equitable Jobs Act (CEJA)[44] requires utilities to share historical investments (5 years prior) and planned investments (5 years forward), along with various distribution system information (substation capacities, miles of wires, load information, DER deployment, etc.).

Data sharing for market activity

DER and EV developers need to be able to easily access and analyze customer, system and market data to identify project opportunities, develop a business case for these projects, connect them to the grid and eventually participate in markets.

- **Customer data:** Green Button Connect (GBC) has been deployed by several utilities, however, implementations vary across utilities in terms of user experience and performance of the service. In addition to providing data via GBC, utilities could adopt metrics on the performance of the GBC service (e.g., API response time, number of customers granted authorization per time interval, etc.). Similar performance metrics have been mandated in California (E-4868), New York (20-M-0082) and Texas (47472)
- **System data:** Hosting capacity maps have been deployed by several utilities, however, the data and specific functionalities available vary across utilities. A common, no-regrets set of system data could be identified that serves as the baseline information provided via these maps to market participants. Moreover, only a select few utilities have built in APIs[45] and embedded interconnection portals, which could also be a standard functionality included in hosting capacity maps.
- **Market data:** Access to rates and programs may be needed to understand and optimize the business case for customers to reduce payback periods and maximize revenue opportunities. We discuss rates in additional detail in the next section.

42 Grid Modernization Advisory Council (GMAC) Final Report, mass.gov/doc/gmac-final-report/download pp 19

43 Grid Modernization Advisory Council (GMAC) Final Report, mass.gov/doc/gmac-final-report/download pp 19 and 24

44 CEJA Section 16-105.17. Multi-Year Integrated Grid Plan

45 The Joint Utilities of New York offer hosting capacity map data available via API, jointutilitiesofny.org/utility-specific-pages/hosting-capacity

Data sharing on rates

Non-utility actors need to be able to easily access and analyze existing and proposed rates to propose alternative rate designs. However, most rates today are provided in PDF format.

The California Energy Commission is currently developing the Market Informed Demand Automation Server (MIDAS) to provide digitized access to utilities' time-varying rates, greenhouse gas emission signals, and California Independent System Operator (California ISO) FlexAlerts.[46] The New York Integrated Energy Data Resource (IEDR), a statewide centralized data platform, is expected to provide a list of rates/tariffs across New York State utilities in a consistent and machine readable format in 2024.[47] Genability (recently acquired by Arcadia Power) digitizes utility tariff and rates books and provides them in API format for different users to access.

CUSTOMER AND AGGREGATOR DATA SHARING WITH UTILITIES

Customer and aggregator data sharing with utilities can enable better rate design and load management programs, more precise capacity planning, and more efficient and reliable operations. The types of customer and aggregator data sharing might include planned load additions, generation data, aggregator historical load and generation profiles, performance during events and equipment settings and capabilities. Utilities have often not been systematic about creating data sharing rules for customers. In many jurisdictions, there are open questions about what kinds of data should be shared, when, and how.

- Several utilities, including those in Massachusetts[48], New York[49] and Connecticut require EV customers to provide their EV charging data as a requirement for receiving incentives from the make-ready program.
- Interconnection is a point at which data from DERs can be collected. California has adopted NIST 44 as a standard for collecting data at the point of interconnection.
- Several utilities, including those in Massachusetts and Illinois, have proposed to rely on aggregators to enable virtual power plant (VPP) programs. It is expected that aggregators will be expected to provide some level of performance data to justify receiving payments.

DATA SHARING PLATFORMS

Data sharing platforms can be designed for either static applications (Distribution planning, rate design, targeted/integrated deployment strategies and grid connection all require relatively static data) or in a more frequent (possibly real-time) manner.

46 energy.ca.gov/proceedings/market-informed-demand-automation-server-midas

47 nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program/Use-Case-Development

48 Massachusetts Utilities have agreed to track all the metrics listed here: fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18215654

49 New York utilities were ordered to track the metrics listed here: documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6057D98B-0000-C912-9B64-A2D769C4790D

Potential characteristics for static data sharing platforms

- Common data standards
- Machine-readable format
- Statewide or utility consolidated platform: New York, Texas and New Hampshire are working towards statewide data platforms; Illinois commission has asked utilities to work with stakeholders to build consensus on data sharing, and will then investigate a statewide platform. National Grid has a dedicated system data portal in Massachusetts.[50]
- Independent governance
- Independent (state) or utility-led development: NYSERDA is leading New York's platform (however, there are only a handful of states that have a state agency with the capacity of NYSERDA); New Hampshire and Texas are having the utilities and state organizations jointly lead the development of their platforms.

Potential characteristics for real-time data sharing

Distribution operators require managing different system conditions at different intervals, and often with different types of assets. Different DERs will require different data sharing/communication protocols, depending on how they are managed (e.g., networked chargers participating in active managed charging programs use the OpenADR protocol to receive dispatch signals from the utility, which is different from how a DERMS interacts with community solar). It is likely infeasible for there to be one operational platform with a single protocol and integration for the market to access. However, the utilities can provide one place that clearly defines which services require certain protocols, integrations and technical requirements.

In any data sharing platform, where possible, existing standards should be leveraged—Green Button Connect, DataGuard, OpenADR, DNP3, CTA-2045, IEEE 1547-2018

DATA SHARING CASE STUDIES

- Massachusetts Grid Modernization Advisory Council (GMAC), 2023, *Observations and Recommendations of the Grid Modernization Advisory Council*, mass.gov/doc/gmac-final-report/download
- NYSERDA, *Integrated Energy Data Resource*, nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program
  - New York Department of Public Service, 2020, S*taff whitepaper: recommendation to implement an integrated energy data resource*, documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b43298F6A-3CA4-435F-BC9D-6DEF6F575836%7d
  - State of New York Public Service Commission, 2021, *Order implementing an integrated energy data resource*, documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b3CDC0522-7F50-49E1-A053-EA236B3DED10%7d
- California Public Utilities Commission, *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*, Rulemaking 22-07-005, Track B working group report and notice of availability, See pp. 234 for a description of challenges encountering in data

50 systemdataportal.nationalgrid.com/MA/

sharing between California IOUs and CCAs docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541672.PDF (which can be found on this page docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=520541672)

- UK Power Networks, UK Power network open data portal (website) ukpowernetworks.opendatasoft.com/pages/home

PRE-WORKSHOP SUGGESTED READING

- NARUC, 2023, NARUC grid data sharing playbook, pp. 3-4 (PDF pp. 8-9), pubs.naruc.org/pub/E2E50FD7-CD1B-62D5-1071-8D8362AD1E6D?utm_source=NARUC+Alerts+%28MM%29&utm_campaign=0a5b9a94c6-EMAIL_CAMPAIGN_2023_10_19_04_51_COPY_01&utm_medium=email&utm_term=0_-bce21179d2-%5BLIST_EMAIL_ID%5D&mc_cid=0a5b9a94c6&mc_eid=83b67482db

ADDITIONAL REFERENCES

These resource pertain mainly to the "Utility data sharing with external partners and the public" mode of data sharing:

- Mission Data, missiondata.io/reports
- Berkeley Law Center for the Law, Energy and the Environment, 2021, *Data access for a Policy Report decarbonized grid*, law.berkeley.edu/wp-content/uploads/2021/02/Data-Access-for-a-Decarbonized-Grid-February-2021.pdf
- Institute for Market Transformation, *Model utility data access law*, imt.org/resources/model-utility-data-access-law
- ACEEE, 2020, *Improving access to energy usage data*, aceee.org/toolkit/2020/02/improving-access-energy-usage-data
- US Department of Energy, 2023, *Data access guidelines*, energy.gov/sites/default/files/2023-07/IRA-50121-Home-Efficiency-Rebates-Data-Access-Guidelines-1.0.pdf

charged

Charting a path for Greater Electrification on the Distribution system