Title

Bridging the Gap on Data and Analysis for Distribution System Planning: Information That Utilities Can Provide Regulators, State Energy Offices and Other Stakeholders

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Bridging the gap on data and analysis for distribution system planning

Information that utilities can provide regulators, state energy offices and other stakeholders

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Bridging the Gap on Data and Analysis for Distribution System Planning:
Information That Utilities Can Provide Regulators, State Energy Offices and Other Stakeholders

Prepared for the
Office of Energy Efficiency and Renewable Energy
U.S. Department of Energy

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Acronyms and Abbreviations

BCA	benefit-cost analysis
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CEMI	Customers Experiencing Multiple Interruptions
COP	coefficient of performance
DER	distributed energy resources
DOE	U.S. Department of Energy
EPRI	Electric Power Research Institute
EJ	Environmental Justice
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
HCA	hosting capacity analysis
IDSP	integrated distribution system planning
IEEE	Institute of Electrical and Electronics Engineers
kvA	kilovolt-ampere
kW	kilowatt
LRC	lowest reasonable cost
MAIFI	Momentary Average Interruption Frequency Index
MODA	multi-objective decision analysis
MW	megawatt
NERC	North American Electric Reliability Corporation
NWA	non-wires alternative
NYISO	New York Independent System Operator
OT/IT	operational technology/information technology
PG&E	Pacific Gas & Electric
PUC	public utilities commission
PV	photovoltaics
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SCE	Southern California Edison

Executive Summary

U.S. investor-owned utilities spent an estimated $59.7B on electric distribution system investments in 2024, accounting for the largest portion of capital expenditures — 32 percent, according to the Edison Electric Institute. Utilities conduct planning annually to ensure their distribution system meets technical standards, policies, and regulations; addresses forecasted grid conditions; satisfies customer needs; and advances utility priorities. The plan identifies grid deficiencies, analyzes potential solutions, and prioritizes capital investments and other distribution expenditures.

While all utilities conduct planning, about 20 U.S. states and jurisdictions require regulated utilities to file some type of distribution system plan with the public utility commission (PUC) for review. Requirements for sharing distribution system data and analyses vary widely, from few specific requirements to a detailed list of information that must be provided.

While utilities conduct extensive analysis to develop distribution system plans, in most jurisdictions regulators and stakeholders do not know what data are available and how the utility uses the data in planning and investing. This report aims to bridge the gap by increasing understanding of the types of data and analyses utilities employ to develop distribution system plans and how the information affects their decision-making.

The report describes information that states and stakeholders can ask for related to 11 data categories:[1]

1. Forecasting loads and distributed energy resources (DERs)
2. Scenario analysis
3. Worst-performing circuits
4. Asset management strategy
5. Hosting capacity analysis
6. Value of DERs
7. Grid needs assessment
8. Cost-effectiveness evaluation for investments
9. Distribution system investment strategy and implementation
10. Geotargeted programs
11. Non-wires alternatives (NWAs) procurements

Following is a summary of the types of data available for each of these categories and impacts on distribution system planning. Sharing such data provides transparency into the utility's planned capital investments and operation and maintenance expenditures over time. Providing a longer-term, holistic picture of interdependent distribution system investments before they show up individually in utility rate cases facilitates regulatory and stakeholder review and understanding as well as improved oversight of distribution system costs on behalf of utility customers. Transparent distribution system

[1] Berkeley Lab's Integrated Distribution System Planning website includes an interactive planning framework with additional information on these and other data categories.

data and analysis also are useful for review of proposed DER programs and retail rates and enable consumers and third-party providers to propose grid solutions and participate in providing grid services.

Berkeley Lab's data collection tool for this report, in Excel, is available at https://emp.lbl.gov/publications/bridging-gap-between-utilities-and-0. Utilities, regulatory commissions, state energy offices, and other stakeholders can adapt the tool to meet their needs.

1. Forecasting Loads and DERs

Load and DER forecasting informs the timing, need, and type of distribution system investments required to meet estimated peak demand at specific grid locations and times. These forecasts are inputs for multiple distribution planning activities, including assessing grid needs and considering non-wires alternatives. The forecasts also can inform other electricity planning processes such as resource and transmission planning.

Data category	Type of data reported	Impact of data on planning
Gross load forecast	Model parameters and sources	Provides transparency and enables regulators and stakeholders to validate utility decisions and propose alternatives and scenarios
Load-modifying technologies and distributed generation	Input assumptions and modeling decisions on technologies that affect load growth	
New construction	Size, timing, and location of new loads	Characterizes future grid conditions, identifies drivers of increased peak demand, and informs grid investment strategies
Forecast outputs	Peak demand	

2. Scenario Analysis

Scenario analysis examines a range of plausible futures based on potential trajectories of drivers, such as economic and technological factors and weather impacts. Scenarios identify challenges and risks that the distribution system may face in the future and help the utility manage uncertainty by analyzing a range of conditions.

Data category	Type of data reported	Impact of data on planning
Scenario structure	Narrative descriptions	Identifies the types of uncertainties addressed by scenarios
Scenario assumptions		Documents the range of uncertainties used and supports assessment of reasonableness of assumptions
Implications for planning activities		Increases awareness of planning risks and informs discussion of risk mitigation and adaptation

3. Worst-Performing Circuits

Utilities analyze the duration, frequency, and number of customer service interruptions to identify circuits (feeders) with the poorest reliability. For these worst-performing circuits, utilities assess potential root causes and develop remediation plans to improve reliability.

Data category	Type of data reported	Impact of data on planning
Identification of worst-performing circuits	Metrics, methods, and criteria for selecting worst-performing circuits	Focuses efforts on circuits with the poorest performance and resulting local grid conditions
Worst-performing circuit characteristics	Circuit technical details, customer counts and classes, reliability performance, event and maintenance history	Provides historical and operational context for understanding circuit reliability
Remediation plans	Criteria for developing a remediation plan and planned remediation actions	Specifies how utilities plan to respond to known drivers of poor reliability performance

4. Asset Management Strategy

Asset management encompasses all of the ways utilities make decisions about building and maintaining distribution infrastructure. Asset management spans the full life-cycle, from initial equipment selection to design and construction practices to inspection and maintenance and, ultimately, replacement. Common decision-making elements in executing an asset management strategy include assessing asset performance, maintaining and improving reliability and resilience, and efficient budgeting and allocation.

<table>
<tr><th>Data category</th><th>Type of data reported</th><th>Impact of data on planning</th></tr>
<tr><td>Standards and guidelines</td><td>Equipment and design standards, engineering guidelines</td><td>Shapes physical grid infrastructure and types of solutions available to address system challenges</td></tr>
<tr><td>Asset and reliability data</td><td>Reliability indices, equipment testing and inspection data, device settings</td><td rowspan="3">Impacts distribution infrastructure and provides opportunities to coordinate asset management with distribution system planning to optimize spending on capacity upgrades</td></tr>
<tr><td>Programmatic asset-related investments</td><td>Utility programs and associated goals and budgets</td></tr>
<tr><td>Discrete asset management investments</td><td>Asset needs identification and prioritization</td></tr>
</table>

5. Hosting Capacity Analysis

Utilities determine the amount of DERs that can interconnect at a specific point on the grid without infrastructure upgrades or adversely impacting power quality or reliability under existing control and protection systems. Hosting capacity analysis models existing grid conditions and simulates power flow at various levels of DER penetration to determine hosting capacity for distributed generation, battery storage, or new loads such as electric vehicle (EV) charging. Hosting capacity maps can serve as a guide for developers to evaluate potential project sites. Utilities can use hosting capacity information in interconnection processes, as well as in distribution system planning to identify the location and causes of distribution system constraints and assess options to mitigate them.

<table>
<tr><th>Data category</th><th>Type of data reported</th><th>Impact of data on planning</th></tr>
<tr><td>Analytical framework</td><td>Criteria for updating hosting capacity analysis and key methodological decisions</td><td>Provides transparency and enables regulators to validate utility decisions and propose alternatives</td></tr>
<tr><td>Distribution system infrastructure attributes</td><td>Locational, technical, and operational information on substations and feeders</td><td>Informs siting of DERs and loads absent power flow simulations</td></tr>
<tr><td>Load characteristics</td><td>Peak and minimum demand</td><td rowspan="2">Informs siting of DERs and loads</td></tr>
<tr><td>DER capacity</td><td>Installed and queued DER capacity</td></tr>
<tr><td>Hosting capacity estimates</td><td>Generation, load, and storage hosting capacity</td><td>Informs siting, sizing, and operations of DERs and EV charging stations</td></tr>
<tr><td>Mitigation analysis</td><td>Options and costs for mitigating constraints</td><td>Provides transparency, enables validation of utility analyses, and provides insight into utility investment decisions and potential alternatives</td></tr>
</table>

6. Value of DERs

Utilities quantify the benefits of DERs to the distribution system to inform compensation and guide deployment. More accurate valuation of DERs in distribution planning can help guide DER deployment to areas that improve distribution system outcomes or prevent or defer future distribution system investments.

Data category	Type of data reported	Impact of data on planning
Distribution system input data	Distribution growth expectations, capacity needs, and historical costs	Informs DER programs, which can affect future distribution system planning needs
DER input data	DER types and associated performance characteristics	
Distribution DER value drivers	Value drivers considered and corresponding quantification methodologies	

7. Grid Needs Assessment

A grid needs assessment is an output of distribution system analysis that transparently identifies specific grid deficiencies over a set period. Utilities leverage data from other distribution system analyses for the assessment, including load and DER forecasting and scenario analysis. The assessment includes a description of the deficiency, associated engineering characteristics, and timing of the need. The grid needs assessment informs the utility's distribution system investment strategy, including both traditional grid upgrades and pricing, programs, and procurements for NWAs.

Data category	Type of data reported	Impact of data on planning
Scope	Objectives and regulatory compliance	Establishes the breadth and depth of the assessment and how it fits into the utility's distribution system planning strategy
Analytical approach	Methodology, limitations, and tools	Characterizes the approach implemented to identify grid needs
Grid needs identification	Asset characteristics, description of grid need, cost estimates, timing of grid need, and engineering characteristics	Identifies assets impacted by grid deficiencies
Grid needs selection	Grid needs prioritization and solutions	Selects grid needs for near-term investments and describes the approach that will be used to identify solutions

8. Cost-Effectiveness Evaluation for Investments

Cost-effectiveness evaluation assesses the benefits and costs of grid investments and qualitative factors to achieve established planning objectives to determine an optimal course of action. Utility data on cost-effectiveness can support regulators in assessing and determining which investments may be appropriate for approval and deployment.

Data category	Type of data reported	Impact of data on planning
Solution justification data	Description of selected investments and other expenditures, expected outcomes, investment drivers (compliance with standards, regulations, or policies or enabling other new capabilities), and engineering analyses	Identifies alternatives considered, selected solutions, and rationale
Cost-effectiveness analysis screening	Scope of analysis (individual solution or integrated set of technologies), screening method, estimates of benefits and costs, uncertainty analyses, and ex-post results from prior distribution plans	Determines approach (lowest reasonable cost or benefit-cost analysis) the utility uses for initial economic evaluation of proposed expenditures based on investment drivers
Portfolio development	Scoring and ranking methods (e.g., multi-objective decision analysis, value-spend efficiency) and results, planned portfolio of expenditures	Prioritizes screened expenditures based on cost and potential contribution toward achieving planning objectives to create value for utility customers and society

9. Distribution System Investment Strategy and Implementation

The investment strategy is the utility's plan to achieve the objectives established for distribution system planning. The strategy addresses asset management; reliability and resilience investments including physical upgrades, advanced technologies, and microgrids; capacity expansion including physical upgrades and non-wires solutions, such as customer load flexibility and DER services; and advanced grid technology including for monitoring and control capabilities. The strategy also may include network and data management, planning and operational analytics, and DER enabling technologies.

Data category	Type of data reported	Impact of data on planning
Strategy development	Vision, objectives, strategy and investment drivers, capabilities and functionalities, grid architecture, and strategic roadmap	Characterizes the long-term evolution of the distribution system and enables regulators to assess alignment with state policy goals and objectives, as well as planning requirements
Strategy implementation	Progress to date, future implementation, investments planned, costs and financing, and risks and mitigation	Connects long-term strategic plans with near-term actions, allowing regulators to understand progress and assess the adequacy of proposed investments in relation to the utility's long-term strategy

10. Geotargeted Programs

Geotargeted programs provide incentives for DERs to reduce load growth for specific locations on the distribution system and reduce the need for upgrades. Utilities and third-party administrators can offer an upfront rebate or other incentive for customers to install a specific technology and opportunities to earn revenues by operating technologies to reduce distribution peak demand.[2]

Data category	Type of data reported	Impact of data on planning
Program needs	Program goals, locational characteristics, and operational and technical requirements	Defines suitability and technical characteristics of geotargeted programs to meet grid needs
Program design and deployment	Eligible measures, program duration, customer participation, and marketing, education, and outreach	Identifies program elements and deployment activities
Evaluation of program performance	Technologies and measures deployed, program effectiveness, community engagement, program budget, and cost-effectiveness	Supports decision-making on continuing and refining program design and deployment

[2] Geotargeted pricing for the distribution system is nascent. See Carvallo, J., and L. Schwartz, 2024, [The use of price-based demand response as a resource in electricity system planning](#).

11. Non-Wires Alternatives Procurements

Utilities can use energy storage, demand flexibility, managed EV charging, and other DERs to provide grid services at specific locations on the distribution system to reduce, defer, or avoid the need for upgrades to infrastructure such as circuits or substations. These NWAs — both front-of-meter and behind-the-meter DERs — can lower peak demand, address voltage issues, improve resilience, and reduce power interruptions.

Data category	Type of data reported	Impact of data on planning
Suitability screening	Criteria for determining whether an NWA is suitable, for a known grid need	Identifies whether NWA processes and technologies are practical for addressing a specific grid need
Technical and cost-effectiveness screens	Methods and input assumptions for determining whether NWA can resolve grid need cost-effectively	Helps regulators understand utility decision whether to pursue NWA
NWA opportunities	Project descriptions and grid need characteristics for NWAs that pass screens	Prescribes how the NWA should perform and informs the selection and operation of NWA DERs
Procurement process	Timeline, review process, bidding rules, and contingency plans	Sets expectations for regulators and NWA providers on how utility procures NWA solutions
Performance evaluation	Data requirements, data cleaning assumptions, and performance metrics	Helps regulators validate utility evaluation methods and NWA vendors achieve desired outcomes

1. Introduction

More than 20 states and jurisdictions in the United States require electric utilities to file some type of distribution system plan.[3] Requirements for sharing planning data and analysis vary widely.

Significant utility investments to replace aging infrastructure and modernize distribution grids — for example, to integrate DERs and electric vehicles (EVs), facilitate grid services by customers and DER aggregators, maintain reliability and resilience in the face of increasing threats, and improve grid flexibility — are increasing interest in distribution system planning. But utility regulators and stakeholders often do not know:

- The breadth, depth, and robustness of available data
- How utilities use the data in planning
- How the data and analysis affect utility decisions

Previous reports on grid data-sharing focused on state requirements,[4] frameworks,[5] or specific types of data such as information used to determine hosting capacity for DERs and DER valuation.[6] This report aims to bridge the gap between utilities and utility regulators — and stakeholders such as state energy offices and utility consumer advocates — on a broad range of grid data available from utilities. The guide describes the types of distribution planning data that state agencies and stakeholders can ask for and the potential impact such data have on distribution system plans and utility and regulatory decision-making.

1.1 Methods

Berkeley Lab researchers reviewed utility distribution plans filed with PUCs to identify data and analyses relevant to the categories covered in this report and assess how the utility used the information. Data categories were selected from key topics in Berkeley Lab's Interactive Decision-Making Framework for Integrated Distribution System Planning. Researchers organized the information in a data collection tool using a structure aligned with this framework. The tool is posted here in Excel format to make it easy for utilities, regulators, and stakeholders to adapt it for their own needs.

Berkeley Lab researchers also interviewed representatives of electric utilities, public utility commissions, and state energy offices (Appendix A) about the types of data and analyses shared in distribution planning proceedings, information-sharing approaches and issues, ways stakeholders use

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[3] Berkeley Lab, online catalog of State Distribution Planning Requirements.

[4] National Association of Regulatory Utility Commissioners (NARUC), Grid Data Sharing: Brief Summary of Current State Practices, 2022.

[5] NARUC, Grid Data Sharing Framework, 2023; NARUC, Grid Data Sharing Playbook, 2023.

[6] See, for example, Electric Power Research Institute, 2018, Key Decisions for Hosting Capacity Analyses; Interstate Renewable Energy Council (IREC), 2021, Key Decisions for Hosting Capacity Analyses; IREC and National Renewable Energy Laboratory, 2022, Data Validation for Hosting Capacity Analyses; and NYSEG/RG&E, Benefit Cost Analysis (BCA) Handbook, 2023.

the information, and impacts of data sharing on distribution planning and utility and regulatory decision-making.

1.2 Data-Sharing Findings From Interviews

Information-sharing approaches and issues - Interviewees identified several approaches that utilities use to share information:

- Annual utility reports
- Data requests in formal proceedings or through informal methods
- Discussions outside of proceedings, such as stakeholder working groups
- Utility-hosted websites (e.g., hosting capacity maps) and data portals

Interview participants also identified several data-sharing issues, summarized below, including managing large volumes of data, lack of standardized data, inconvenient data formats, and utility data systems and processes. Participants also described how litigated distribution planning proceedings can hamper data sharing and offered perspectives on how non-litigated processes such as utility- or commission-convened stakeholder working groups can support data sharing.

The large volume of data in distribution planning proceedings can create burdens for utilities as well as regulators, state energy offices, and other stakeholders. For utilities, data reporting can reduce the time for planning analysis and engagement with regulators and stakeholders.

Data overload can make it difficult for regulators and stakeholders to prioritize their review and evaluate information provided. Lack of technical expertise and staff capacity adds to this challenge. One regulator noted that a large volume of data requests can lead to proceedings that focus on compliance with planning requirements instead of focusing on progress toward planning goals. Both utilities and regulators identified strategies to address these challenges. Utilities interviewed said they can educate regulators and stakeholders about the data and automate processes to reduce staff effort in fulfilling reporting requirements. One utility cited progress toward a largely automated process for cleaning hosting capacity data and modeling, reforming a time-intensive manual process. Another utility opined that a use case-based approach could better align data sharing with regulator and stakeholder needs.

Regulators offered the following strategies for mitigating data overload:

- Initially request historical and other data that is readily available
- Establish information filing requirements at the start of distribution planning processes
- Ask utilities to explain cost categories in advance of filing distribution system plans that specify planned investments and other expenditures
- Require data sharing in between plan filings to identify errors before the next filing is due
- Make data requests specific — for example, ask for 15-minute meter data instead of simply “load data” — to avoid misinterpretation by the utility
- Identify what data overlaps distribution planning and other filings, what data is missing, and what data is superfluous

Despite confronting data overload, regulators and state energy offices said they find value in extensive reporting of data for distribution planning. One regulator noted that it can be helpful to have data on hand in case it becomes useful later in the proceeding. A state energy office noted that *integrated* distribution system planning can reduce the effort of staff coordinating across multiple dockets and topics by consolidating data into a single docket.

Regulators and state energy offices observed a lack of standardized data reporting, with the format and definition of each data field varying across utilities and even within utilities, noting that such variation makes it hard to find information and benchmark utility performance. Regulators and stakeholders suggested that standard data dictionaries, cost categories, and reporting templates could address these issues.

Regulators and state energy offices also noted that the format and granularity of utility data can hinder their review of the plan. Utilities often report data in tables embedded in PDFs, which regulators and stakeholders cannot easily analyze. Regulators and state energy offices both expressed a preference for spreadsheets. While more granular data can facilitate more analyses by regulators and stakeholders, a state energy office representative opined that it is reasonable to expect that the granularity of data that the utility shares would correspond with the size of the utility and, in turn, the resource capacity of the utility, as well as filing requirements and level of DERs installed.

Utilities acknowledged that internal systems and processes can affect the availability and quality of distribution planning data. For example, one utility noted that internal data silos can limit the planning team’s access to advanced metering infrastructure data. Another utility pointed out that load data for the distribution system may not be available due to a lack of monitoring equipment as well as recording errors. Based on their experience, a state energy office said that utility data systems cannot easily fulfill the agency's data requests in distribution planning proceedings. The agency also noted that updates to utility data systems present opportunities for additional data requests if the utility makes updates with improved information-sharing in mind.

Utilities, regulators, and state energy offices all identified challenges to data sharing in distribution planning proceedings and benefits of coordination outside of litigated processes. They noted that litigated proceedings may offer limited opportunities for clarifying questions about utility data and processes. Utilities offered the following ways that informal stakeholder engagement processes can address these challenges:

- Lower the stakes of discussions, since utility statements on are not on the record
- Allow for more conversation and transparency
- Provide an opportunity to discuss what data are needed and useful
- Involve perspectives of data users who have insight into what data is most useful — for example, DER developer perspectives on hosting capacity data

Similarly, one regulator shared that regular meetings with utilities before filings made data requests easier by providing an opportunity to discuss what commission staff were looking for. This cooperative approach made the utilities more willing to share data.

Using information shared by utilities - Regulators and stakeholders provided examples of how they used distribution planning data provided by utilities to:

- Compare historical, actual, and projected expenditures by a utility and across utilities
- Review and validate utility modeling decisions (e.g., load forecast assumptions)
- Map granular reliability data to socio-economic data to identify equity issues
- Conduct benefit-cost analyses using data on distribution asset capacity and depreciation schedules
- Track circuit reliability — with and without major storm impacts — over time to inform prioritization of investments
- Use cost-effectiveness data to inform commission approval of grid investments

Impacts on planning and utility and regulatory decision-making - Participants identified the following impacts related to data shared by utilities:

- Data for a new reliability metric (CEMI-4) introduced by the utility led to Commission approval of investments
- Regulator's identification of errors in reporting data revealed issues with utility meter installations
- Regulator's analysis found that reduction in utility staffing was correlated with poor reliability, which ultimately led to the utility improving reliability
- Validation by the state energy office of utility assumptions on battery storage growth rates
- Coordination between the state transportation agency and utilities as a result of utility data accessed by state energy office

1.3 Report Organization

The remainder of this report describes each of the 11 data categories covered and provides examples of utility data-sharing practices, as well as best practices for utility data-sharing, for each category:

- Forecasting loads and DERs
- Scenario analysis
- Worst-performing circuits
- Asset management strategy
- Hosting capacity analysis
- Value of DERs
- Grid needs assessment
- Cost-effectiveness evaluation for investments
- Distribution system investment strategy and implementation
- Geotargeted programs
- NWA procurements

2. Forecasting Loads and Distributed Energy Resources

Load and DER forecasting for distribution system planning informs the timing, need, and type of distribution system investments required to meet estimated peak demand at specific grid locations and times. Load and DER forecasts are inputs for multiple planning activities, including grid needs assessment and non-wires alternatives analysis. These forecasts also can inform other planning processes such as resource and transmission planning.

Distribution system plans can share key input assumptions, modeling decisions, and outputs for:

- Forecasts of gross load, which project historical load trends into the future, but do not account for the impacts of weather-driven DERs (e.g., solar and wind), energy efficiency, demand response
- Load-modifying technologies such as energy efficiency, battery storage, demand response, and building and transportation electrification technologies
- Distributed generation such as solar photovoltaics (PV)
- New construction of housing and commercial and industrial facilities (see Table 2-1)

Table 2-1. Load and DER forecasting data and impacts on planning

Data category	Type of data reported	Impact of data on planning
Gross load forecast	Model parameters and sources	Provides transparency and enables regulators and stakeholders to validate utility decisions and propose alternatives and scenarios
Load-modifying technologies and distributed generation	Input assumptions and modeling decisions on technologies that affect load growth	
New construction	Size, timing, and location of new loads	Characterizes future grid conditions, identifies drivers of increased peak demand, and informs grid investment strategies
Forecast outputs	Peak demand	

3.1 Data Inputs

2.1.1 Gross load forecast

Utilities generate gross load forecasts (1) using time extrapolation with simple linear trending for weather and economic factors or (2) applying a regression model that relates historical load to economic, weather, and demographic parameters to forecasts of those parameters over the study period, projecting these parameters and the resulting changes in gross load over the study period.[7] Distribution system plans can report these parameters and data sources for modeling inputs (see Table 2-2). Utilities also may study planning scenarios by varying parameters such as DER penetration (see

[7] Utilities typically model peak loads only, not 8,760 hours.

Scenario Analysis chapter). Transparency on data inputs and sources increases understanding of forecasting methods by stakeholders and enables them to propose alternative inputs and sources.

Utilities generally do not report historical data used in regression models. Hawaiian Electric is an exception. The utility provided spreadsheets of historical and projected model inputs and sources as part of a working group process.[8] Reporting of historical data facilitates stakeholder analysis and model validation. Utilities also generally do not share data on forecasts of modeling parameters, with the exception of weather data. Utilities often report a design temperature defined by some probability of occurrence. For example, a 90/10 design temperature is the historical temperature at which peak demand is higher than 90% of observed peaks and there is a 10% chance of peak demand being higher. A 90/10 temperature sets an upper bound for expected gross peak demand, whereas a 50/50 temperature represents more normal conditions.[9]

Design temperatures typically reflect long-term historical trends, rather than account for recent changes in weather and future climate change. Some utilities are beginning to account for the impact of climate change in gross load forecasts. For example, Hawaiian Electric incorporated a climate change adder to its projection of cooling degree days.[10] Similarly, National Grid explored the impact of temperature increases from climate change on load in its recent Climate Change Vulnerability Study.[11]

Table 2-2. Regression parameters for gross load forecast

Category	Parameters
Economic	Per capita income, unemployment rate
Weather	Cooling or heating degree days, temperature-humidity index
Demographic	Population
Utility Data	Customer count by class, energy sales by class, electricity price

2.1.2 Load-modifying technologies and distributed generation

Utilities can report technology adoption estimates and other assumptions on how load-modifying technologies and distributed generation will operate. Adoption estimates may be at a utility systemwide level or at a feeder level. National Grid New York, for example, estimated systemwide heat pump adoption using installation targets for its energy efficiency programs and stock projections from a state climate change mitigation pathway.[12] The utility then allocated systemwide heat pump adoption to feeders based on historical adoption records and an adoption propensity model that considers customer demographics. National Grid reported adoption data only for its service area (see Figure 2-1), but its documentation of sources helps regulators and stakeholders understand how the forecast aligns

[8] Hawaiian Electric, *Integrated Grid Plan*, May 2023
[9] ComEd, *Multi-Year Integrated Grid Plan*, January 2023
[10] A *degree day* compares the mean (average of high and low) outdoor temperatures recorded for a location to a standard temperature, usually 65° Fahrenheit in the United States. *Cooling degree days* measure how hot the temperature was on a given day or during a period of days. A day with a mean temperature of 80°F has 15 CDDs. U.S. EIA, "Degree Days." n.d.
[11] National Grid New York, *Climate Change Vulnerability Study*, Case 22-E-0222, September 2023
[12] National Grid New York, *2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment*, March 2024

with state policies and expected technology and market changes. Tabular data can facilitate stakeholders and regulators to perform their own analyses, as in Hawaii.[13]

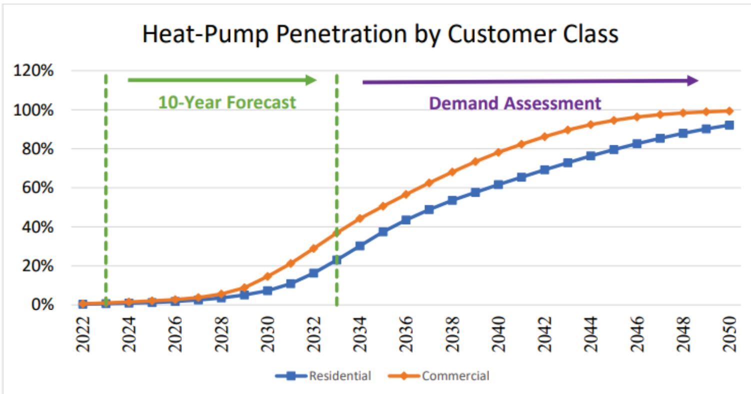

Figure 2-1. National Grid New York service area projections of heat pump adoption

For example, building electrification assumptions can include heat pump efficiency and whether buildings retain the existing heating system as a backup after electrification retrofits.[14] Air-source heat pump efficiency, typically measured by the coefficient of performance (COP), declines with ambient air temperature. Utility assumptions on sensitivity of the COP to temperature, therefore, can affect estimates of winter morning peak demand associated with heat pump adoption. Similarly, retention of existing backup heating systems avoids the adoption of electric resistance backup systems, which can have significant peak demand impacts. For transportation electrification, assumptions for electric vehicle (EV) type[15] (e.g., light duty vehicles, electric buses), vehicle miles traveled, fuel efficiency,[16] and charging strategy[17] impact the timing, location, and magnitude of charging. Utilities also can identify assumptions for battery discharging times and system losses.[18]

Utilities can document sources for all of these modeling decisions. For example, many utilities use EPRI's eRoadMAP™ as a source for EV forecasts. Hawaiian Electric cited the U.S. Energy Information Administration as the source of its fuel economy assumptions, and Green Mountain Power cites historical enrollment in its EV time-of-use rates as the source for its assumed share of managed EV charging.[19] [20] Regulators and stakeholders can use the utility's reported technical assumptions and sources to validate utility decisions and propose alternatives.

Utilities can develop scenarios with different adoption rates and other assumptions for load-modifying technologies for load and DER forecasts (see Scenario Analysis chapter). Xcel Energy in Minnesota, for

13 Hawaiian Electric, *Integrated Grid Plan*, May 2023
14 National Grid New York, *2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment*, March 2024
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19 Hawaiian Electric, 2018-0165. Response to Information Requests, July 2020
20 Green Mountain Power, *2021 Integrated Resource Plan*, December 2021

example, estimated low and high adoption levels of rooftop PV relative to changes in installation costs in a medium scenario.[21] Similarly, National Grid New York documented its assumptions for managed charging for light-duty vehicles in its low scenario and unmanaged charging in its base and high scenarios.[22] Utility reporting on these assumptions enables stakeholders and regulators to understand the conditions that forecast scenarios represent.

2.1.3 New construction

New construction forecasts can account for large new loads that utilities expect to serve in the early years of a forecast (≤5 years), including individual large customers or a group of customers in the same location, such as a residential housing development. Utilities can describe how they identify these new loads and report their size, location, and timing. Eversource, for example, provided a narrative on how it accounts for customers that have requested and been approved for at least 500 kilowatt (kW) service.[23]

2.2 Data Outputs

Load and DER forecast outputs that utilities can share in distribution system plans include estimates of peak demand and impacts of load-modifying resources and distributed generation on peak demand. In general, utilities report peak demand at the distribution substation and/or feeder levels that is not coincident with peak demand utility systemwide. Such noncoincidence reflects maximum demand on a particular location of the local grid.[24] For example, noncoincident peak for a circuit (feeder) informs the need for capacity-related upgrades for that circuit.

The granularity of peak demand forecasts reported by utilities varies in terms of time (e.g., single peak hour of the year vs. hourly load shape) and geography (systemwide vs. circuit level). Typically, utilities report single-hour peak demand estimates for each year of a forecast for their service territory as a whole.[25] Such high-level reporting shows projected overall demand growth, but not how growth varies geographically—today and over time. Alternatively, utilities can provide hourly load shapes for peak days[26] or weeks that include peak days. Green Mountain Power, for example, presented load profiles for weeks that include summer and winter peak days to show how heat pump adoption shifts annual peaks from summer afternoons to winter mornings and how rooftop solar adoption decreases annual minimum net demand (Figure 2-2).[27]

Utilities can provide more geographically granular load forecast results, at the circuit or substation level.[28] NV Energy, for example, provided ratings and annual peaks for individual substation

[21] Xcel Energy Minnesota, *Integrated Distribution Plan 2024-2033*, November 2023
[22] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, March 2024
[23] Eversource Energy, Forecasting and Electric Demand Assessment Methodology, April 2023
[24] In contrast, coincident peak demand for a circuit reflects demand at that location during the utility system's peak demand.
[25] Xcel Energy Minnesota, *Integrated Distribution Plan 2024-2033*, November 2023
[26] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, March 2024
[27] Green Mountain Power, *2021 Integrated Resource Plan*, December 2021
[28] Southern California Edison, 2023 Grid Needs Assessment and Distribution Deferral Opportunity Report, January 2023

transformers in each year of its short-term (five-year) forecast.[29] Circuit- and substation-level peak demand data provide transparency for grid needs assessments, indicating where and when constraints appear.

Forecast outputs for load-modifying technologies include both peak demand impacts and load shapes. As Figure 2-2 shows, Green Mountain Power's peak-week load profile showed the contribution of EV charging (green) and heat pumps (red).[30] Similarly, National Grid New York provided tables detailing increases to peak demand attributable to EV charging and heat pumps, as well as decreases to peak demand resulting from energy efficiency, rooftop PV, energy storage, and demand response for six planning zones.[31] These technology-specific breakdowns of peak demand make clear what technologies drive peak increases and inform peak mitigation strategies.

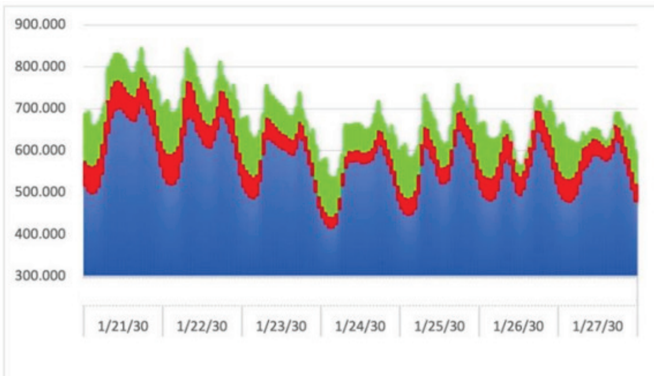

Figure 2-2. Green Mountain Power 2030 winter peak demand week load profile

Note: Blue is baseload net demand, green is EV charging, and red is heat pumps.

2.3 Best Practices

Best practices for sharing data on load and DER forecasting include:

- Identify parameters and design temperatures used in gross load forecasts
- Provide estimates of DER and load-modifying technologies at the feeder-level
- Document assumptions for operation of DERs and load-modifying technologies
- Develop forecasts for different scenarios of DER and load-modifying technology adoption and operation
- Describe criteria for including large new loads in the forecast
- Provide hourly load shapes for peak days that show the impacts of DERs and load-modifying technologies
- Provide estimates of peak demand, and impacts of DERs and load-modifying technologies on peak demand, by circuit

[29] NV Energy, *Narrative Distributed Resources Plan and Technical Appendix*, June 2021
[30] Green Mountain Power, *2021 Integrated Resource Plan*, December 2021
[31] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, March 2024

3. Scenario Analysis

Scenario analysis examines a range of plausible futures based on potential trajectories of planning drivers—either indirect (e.g., economic and technological factors) or direct (e.g., load growth and severe weather impacts).[32] Scenarios can identify challenges and risks that the distribution system may face in the future and can manage uncertainty by analyzing a range of conditions. Scenario analysis uses both quantitative and qualitative information to stress test distribution plans by:

- Determining least-regret investments under different potential conditions
- Assessing needed plan flexibility and plan robustness

Scenarios also can guide decision-making to manage different levels of risk and uncertainty. Table 3-1 summarizes a scenario-based decision-making framework for distribution planning developed by the Electric Power Research Institute (EPRI).[33] The framework describes how an exclusive focus on "no regrets" actions required in *most or all* scenarios can increase the likelihood of risks such as overloads. EPRI also explains how utilities can mitigate risks by taking actions required in *any* scenario and introduce flexibility by staging the implementation of planned actions.

Table 3-1. Scenario-based decision-making framework adapted from EPRI[34]

Approach	Description
No regrets	Proceed with actions necessary for all or most scenarios.
Most likely	Apply "likelihood factors" to move forward with initiatives that are more likely to be necessary.
Worst case	Address the full range of risks that develop in any of the scenarios.
Leveraged	Proceed with actions with a higher operational risk (No regrets/Most likely) and scale project to address a worst-case scenario.
Staged	Proceed with worst-case actions but advance the necessary elements in multiple phases.

Utilities can provide narratives in distribution system plans that describe the structure of scenarios used, assumptions that differentiate scenarios, and implications of scenarios on planning activities (see Table 3-2). Reporting on these planning activities can provide additional data that reflect the scenarios.

[32] Scenarios are distinct from contingency planning procedures in which utilities assess the ability of circuits or transformers to serve load while adjacent infrastructure is not energized due to maintenance or equipment failures.
[33] EPRI, Distribution System Scenario Planning, August 2024
[34] EPRI, Distribution System Scenario Planning, August 2024

Table 3-2. Scenario analysis data categories and impacts on planning

Data category	Type of data reported	Impact of data on planning
Scenario structure	Narrative descriptions	Identifies the types of uncertainties addressed by scenarios
Scenario assumptions		Documents the range of uncertainties used and supports assessment of reasonableness of assumptions
Implications for planning activities		Increases awareness of planning risks and informs discussion of risk mitigation and adaptation

3.1 Data Inputs

3.1.1 Scenario structure

Utilities that use scenario analysis in distribution planning typically use one of the following approaches:[35]

1. *Alternative futures scenarios* are used in the forecasting process to understand a range of plausible futures as an input for planning, such as a base case, high case, and low case. For example, DTE Electric considered electrification, distributed generation, and catastrophic storm scenarios in its 2023 Distribution Grid Plan.[36] The electrification scenario explores EV adoption greater than expected in the reference forecast for the utility's 2022 integrated resource plan.[37] The high distributed generation scenario considers increased adoption of PV and battery storage. In New York, National Grid differentiates PV adoption in its base and high scenarios by the share of the state's 2050 target for state PV deployment achieved.[38] Similarly, Xcel Energy Minnesota examines base case, medium, and high levels of DER adoption in accordance with state requirements to address uncertainty in DER deployment.[39] [40]
2. *Discrete scenarios* are used in distribution planning to assess least-regret investments that address more than one critical issue. Critical issues typically are driven by key factors that are largely independent of each other and have material impacts on grid needs. For example, electrification growth is independent of increasing storm severity with respect to distribution system impacts. The utility selects scenarios from the alternative futures described above. The

[35] Alternatively, utilities can use sensitivities of various forecast variables based on Monte Carlo analysis and provide a probability distribution for each variable. Sensitivity analyses for scenarios explore a change in outcomes due to a change in a single input. They are typically used for load and DER forecasting and for climate/weather projections for resilience assessments.
[36] DTE Electric, *2023 Distribution Grid Plan, Case U-20147*, September 2023
[37] De Martini, "Integrated Distribution System Planning," presentation for National Rural Electric Cooperative Association, September 2024
[38] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, March 2024
[39] Xcel Energy Minnesota, *Integrated Distribution Plan 2024-2033*, November 2023
[40] Minnesota Public Utilities Commission, Docket 18-251, Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy, August 2018

objective of discrete scenarios analysis is to determine the potential impact of each of the factors studied to identify overlapping grid needs for least-regret investments.

Narratives can describe the structure of the scenarios the utility used and identify uncertainties addressed.

3.1.2 Scenario assumptions

Assumptions that define scenarios can address uncertainty related to technology adoption, efficiency, and operations. For example, Xcel Energy in Minnesota considered greater EV adoption in a high scenario using lower battery prices and higher gasoline prices relative to its medium scenario.[41] Hawaiian Electric illustrated how utilities can make assumptions about types of technologies customers will install and how customers will use them. As Table 3-3 shows, Hawaiian Electric explored a high value for peak demand by assuming that customer EV charging is unmanaged in its High Load and Unmanaged Electric Vehicles scenarios.[42] Such documentation identifies the range of uncertainties that the utility factors into planning activities. This information enables regulators and stakeholders to assess whether scenarios align with state policies, expected market and technology changes, and climate change mitigation pathways.

Table 3-3. Hawaiian Electric 2023 Integrated Grid Plan scenario assumptions[43]

Modeling Scenario	Purpose	DER Forecast	EV Forecast	EE Forecast	Non-DER/EV TOU Forecast	EV Load Shape	Fuel Price Forecast	Resource Potential
Base	Reference scenario.	Base	Base	Base	Base	Managed EV charging	Base	NREL Alt-1
Land-Constrained	Understand the impact of limited availability of land for future solar, onshore wind and biomass development.	Base	Base	Base	Base	Managed EV charging	Base	**Land-Constrained Resource Potential**
High Load	Understand the impact of customer adoption of technologies for DER, EVs, EE and TOU rates that lead to higher loads.	**Low**	**High**	**Low**	**Low**	**Unmanaged EV charging**	Base	NREL Alt-1
Low Load	Understand the impact of customer adoption of technologies for DER, EVs, EE and TOU rates that leads to lower loads.	**High**	**Low**	**High**	**High**	Managed EV charging	Base	NREL Alt-1
Faster Technology Adoption	Understand the impact of faster customer adoption of DER, EV and EE.	**High**	**High**	**High**	**High**	Managed EV charging	Base	NREL Alt-1
Unmanaged Electric Vehicles	Understand the value of managed EV charging relative to unmanaged.	Base	Base	Base	Base	**Unmanaged EV charging**	Base	NREL Alt-1
DER Freeze	Understand the value of the distributed PV and BESS uptake in the Base forecast. Informative for program design and solution sourcing.	**DER Freeze**	Base	Base	Base	Managed EV charging	Base	NREL Alt-1
Electric Vehicle Freeze	Understand the value of the electric vehicle's uptake in the Base forecast. Informative for program design and solution sourcing.	Base	**EV Freeze**	Base	Base	Managed EV charging	Base	NREL Alt-1
High Fuel Retirement Optimization	Understand the impact of higher fuel prices on the resource plan while allowing existing firm unit to be retired by the model.	Base	Base	Base	Base	Managed EV charging	**EIA High Fuel Price**	NREL Alt-1
Energy Efficiency Resource	Understand the value of energy efficiency as a resource. Informative for program design and solution sourcing.	Base	Base	**EE Freeze + EE Supply Curves**	Base	Managed EV charging	Base	NREL Alt-1

3.2 Data Outputs

Scenario narratives can identify potential challenges and risks to distribution system planning activities based on analysis performed by utilities or third parties. DTE Electric, for example, describes how EV

41 Xcel Energy Minnesota, *Integrated Distribution Plan 2024-2033*, November 2023
42 Hawaiian Electric, *Integrated Grid Plan*, May 2023
43 Hawaiian Electric, *Integrated Grid Plan*, May 2023

adoption could increase the number of capacity-constrained substations, resulting in higher risks of outages during grid contingencies. Similarly, ComEd discusses the risks of climate change in its 2023 Integrated Grid plan based on a study the utility conducted with Argonne National Laboratory.[44] [45] The study indicates that longer growing seasons could increase the risk of damage to distribution infrastructure from vegetation and that the utility may need to derate transformer capacity due to higher air temperatures (see Figure 3-1). These narratives can make stakeholders and regulators aware of risks to the distribution system and provide a starting point for further analysis and discussion on mitigating and adapting to identified risks.

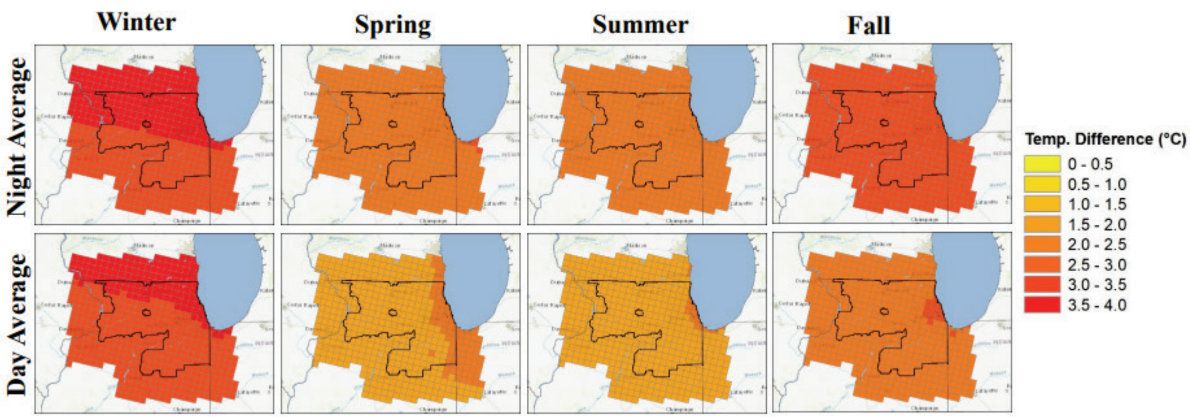

Figure 3-1. Estimates of seasonal daytime and nighttime changes in average minimum temperature: 1995–2004 baseline to mid-21st century[46]

Utilities also can report data on the planning activities to which they apply scenarios. For example, utilities often develop load forecasts across multiple scenarios that differ in trends for customer load, the adoption of EVs, building electrification technologies, distributed generation and storage technologies, and market and fuel prices among other factors. Such scenarios inform detailed system planning analyses that determine potential distribution needs and related scope, scale, and timing considerations.

Salt River Project, for example, estimates the need for major investments in existing and new substations across four scenarios that reflect possible load growth trajectories for the utility (Figure 3-3).[47] The scenarios differ in terms of economic growth, carbon policy, climate change impacts, and technology costs, among other factors. By extending scenarios into grid needs assessment, the utility is able to determine the plausible range of investments it may need to make over the planning period.

[44] ComEd, Multi-Year Integrated Grid Plan, January 2023

[45] Burg, Kartheiser, Mondello, et al., *ComEd Climate Risk and Adaptation Outlook, Phase 1: Temperature, Heat Index, and Average Wind*, November 2022

[46] Burg, Kartheiser, Mondello, et al., *ComEd Climate Risk and Adaptation Outlook, Phase 1: Temperature, Heat Index, and Average Wind*, November 2022

[47] Salt River Project, *2023 Integrated System Plan*, 2023

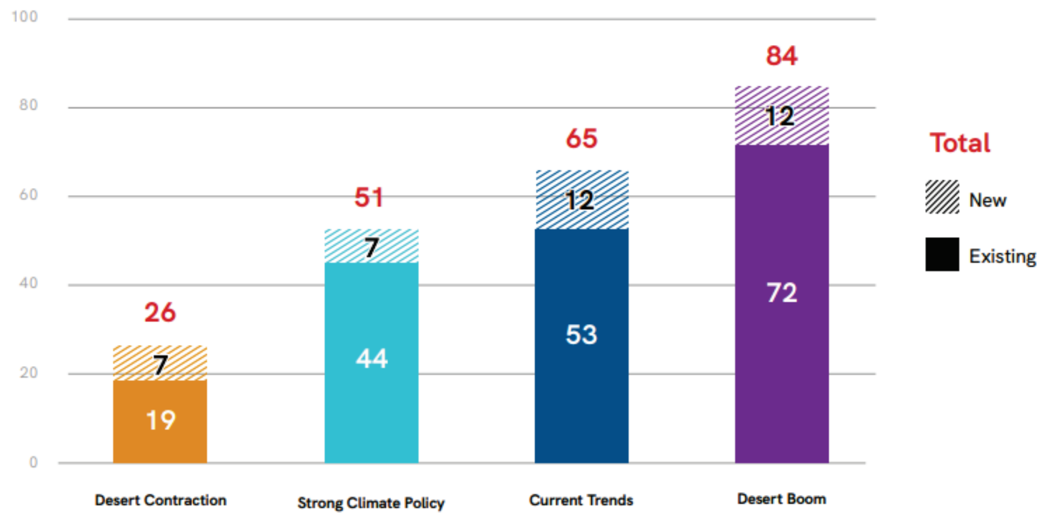

Figure 3-2. Salt River Project substation bay additions through 2045 by planning scenario[48]

3.3 Best Practices

Best practices for sharing data on scenario analysis include:

- Clearly describe the structure of scenarios used and the uncertainties that each scenario addresses
- Document assumptions that differentiate scenarios
- Provide narrative descriptions that identify risks and challenges of planning activities for each scenario
- Report scenario-specific data that utilities apply to scenarios, such as load and DER forecasts

[48] Salt River Project, *2023 Integrated System Plan*, 2023

4. Worst-Performing Circuits

Utility engineers analyze data on the frequency, duration, and number of customer service interruptions to identify circuits (or feeders) with the worst reliability performance. For these "worst-performing circuits," utilities assess potential root causes and develop remediation plans to improve reliability. Many states require that regulated utilities annually submit a list of worst-performing circuits, along with reliability metrics and a remediation plan for each circuit. This process supports prioritizing reliability improvements for customers that have experienced the highest frequency and/or duration of power interruptions.

Data and analyses reported on worst-performing circuits provide transparency into reliability performance for individual circuits and utility processes for selecting circuits for remediation. Utility reporting can describe the metrics and criteria used to classify the worst-performing circuits, provide detailed characteristics of those feeders, and delineate remediation plans (Table 4-1).

Table 4-1. Worst-performing circuit analysis data categories and impacts on planning

Data category	Types of data reported	Impact of data on planning
Identification of worst-performing circuits	Metrics, methods, and criteria for selecting worst-performing circuits	Focuses efforts on circuits with the poorest performance and resulting local grid conditions
Worst-performing circuit characteristics	Circuit technical details, customer counts and classes, reliability performance, event and maintenance history	Provides historical and operational context for understanding circuit reliability
Remediation plans	Criteria for developing a remediation plan and planned remediation actions	Specifies how utilities plan to respond to known drivers of poor reliability performance

4.1 Data Inputs

4.1.1 Identifying worst-performing circuits

Utilities identify worst-performing circuits by ranking them according to reliability performance metrics and applying selection criteria to those metrics. Table 4-2 defines metrics that utilities use to characterize electric power reliability. Utilities can report data on several factors that affect the outcome of worst-performing circuits analysis, including the choice of metric, the types of interruptions eligible for analysis, and the period over which utilities calculate a metric.

Table 4-2. Definitions of common electric power reliability metrics[49]

Metric	Description	Interpretation
SAIFI	System Average Interruption Frequency Index	Total number of sustained interruptions that an average customer experiences over some time period
SAIDI	System Average Interruption Duration Index	Total number of minutes than an average customer is without power over some time period
CAIFI	Customer Average Interruption Frequency Index	Average number of interruptions per customer interrupted over some time period
CAIDI	Customer Average Interruption Duration Index	Time required to restore service for an average customer over some time period
MAIFI	Momentary Average Interruption Frequency Index	Total number of momentary interruptions (< 5 minutes) than an average customer experiences over some time period
CEMI	Customers Experiencing Multiple Interruptions	Individual customers who experience more than some threshold number (e.g., four) interruptions of at least one minute over some time period.

The reliability performance metric that utilities use affects how the frequency, duration, and breadth of interruptions drives which circuits are worst-performing. For example, frequency-based metrics (e.g., SAIFI) prioritize circuits with frequent but short interruptions compared to duration-based metrics (e.g., SAIDI), which prioritize circuits with long-duration interruptions. Interruptions that affect a small number of customers can have a large impact on CAIDI and CAIFI, but not SAIDI and SAIFI, because they quantify impacts on customers interrupted, not all customers served. However, metrics that use averages—whether for frequency, duration, the whole circuit, or customers interrupted—can obscure individual customers that have poor reliability and fail to identify circuits that serve them. CEMI addresses this issue by identifying individual customers with poor reliability, which utilities can then use to identify circuits. Rhode Island Energy,[50] for example, uses CEMI-4 (percent of customers experiencing at least four interruptions of one minute or more in the past year) to prioritize circuits for line reclosers in a program that complements its worst-performing circuit analysis.

Utilities can rank circuit performance with multiple performance metrics. Pacific Gas & Electric,[51] for example, uses both CAIFI and CAIDI to identify worst-performing feeders. Orange and Rockland

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[49] Definitions are from Schellenberg, J., and L. Schwartz. *Grid Resilience Plans: State Requirements, Utility Practices, and Utility Plan Template*, 2024, Table 3-6.
[50] Rhode Island Energy, *Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan*, 2023
[51] PG&E, *2022 Annual Electric Reliability Report*, 2023

Utilities[52] uses a weighted score that accounts for SAIFI and the number of interruptions and customers affected, among other variables.

Some types of outages may be excluded from consideration in reliability metrics. That affects what grid conditions the analysis represents. Excluding interruptions that result from major weather events, maintenance,[53] or generation and transmission issues[54] omits one-off or infrequent events (e.g., major storms) that do not contribute to persistent reliability issues, focusing performance on standard distribution system operations. Metrics are calculated annually, giving significant weight to one-off or infrequent events (e.g., major storms) that do not contribute to persistent reliability issues, which can justify their exclusion.

State reporting requirements may determine which interruptions utilities exclude when calculating reliability metrics. Missouri,[55] for example, requires that utilities use an engineering standard (IEEE-1366) to determine major event days that can be excluded from circuit-level SAIFI scores that inform identification of worst-performing circuits. The standard provides a statistical method for identifying major event days based on daily SAIDI measurements.[56] Absent regulatory guidance, utilities develop and report on their own approaches, such as in New York.[57] For example, National Grid excludes interruptions from major storms but includes interruptions from transmission issues.[58]

Utilities also can share criteria they use for selecting worst-performing circuits based on reliability performance. These criteria often include some defined percentage of circuits with the lowest score for one or more metric. Illinois, for example, identifies any circuit as worst-performing if it is in the one percent highest SAIFI, CAIDI, or CAIFI scores among all circuits (higher score means lower performance).[59] Similarly, Florida defines the three percent of circuits with the most interruptions as worst-performing.[60]

4.2 Data Outputs

4.2.1 Worst-performing circuit characteristics

Table 4-3 identifies data that utilities report on characteristics of worst-performing circuits. Utilities and regulators use the information to track circuit performance over time. Technical details provide context for causes of interruptions, potential remediation actions, and level of effort required. Pacific Gas & Electric,[61] for example, provides the total length of circuits as well as the percent of the circuit length

52 Orange & Rockland Utilities, *Service Reliability Filing for 2022 System Performance*, 2023
53 PG&E, *2022 Annual Electric Reliability Report*, 2023
54 Florida Public Service Commission, Rule 25-6.0455, Annual Distribution Service Reliability Report, 2006
55 Missouri Code of Regulations, Title 20 4240-23.010, 2024
56 IEEE, IEEE 1366-2003, 2004
57 New York Public Service Commission, Case 2-E-1240, 2004
58 National Grid, Annual Electric Reliability Report for 2023, 24-E-0140, 2024a
59 Illinois Commerce Commission, Illinois Administrative Code, 83.1.c.411, 2022
60 Florida Public Service Commission, Rule 25-6.0455, Annual Distribution Service Reliability Report, 2006
61 PG&E, *2022 Annual Electric Reliability Report*, 2023

underground, both of which are relevant to the outages experienced and remediation actions the utility undertakes. Data on the customers served by a circuit, such as the number on medical or life-support systems[62] registered with the utility, indicates the potential health risks of poor reliability.

Table 4-3. Characteristics of worst-performing feeders

Circuit characteristic	Data reported
Identifying information	• Circuit name/ID • Substation name/ID • Location
Technical details	• Voltage • Circuit length
Customers	• Number of customers on circuit by customer class • Number of customers on medical or life-support systems
Event history	• Date of interruptions • Number of customers affected by event • Duration by event • Cause of event
Reliability performance	• SAIDI, SAIFI, CAIDI, CAIFI, MAIFI • Total duration of interruptions • Total number of customers interrupted • Number of interruption events • Number of equipment outage events • Years in which circuit has been on worst-performing list
Maintenance history	• Date of last tree trimming • Date of last inspection • Description of measures already taken to address previously identified reliability issues • Cost and timeline for actions already taken to address previously identified reliability issues

Event history data can include the causes and impacts of individual interruptions to inform mitigation strategies. New York State Electric and Gas Company, for example, reports the number and duration of interruptions and number of customers interrupted by standard causes such as trees, overloads, equipment failure, and lightning (Table 4-4).[63] This detailed breakdown makes it clear to regulators what remediation efforts (e.g., tree trimming or equipment replacements) are most likely to improve reliability.

62 Ohio Administrative Code, 4901:1-10-01, 2024
63 New York State Electric and Gas, 2022 Annual Reliability Report, 2023

Table 4-4. Causes of interruptions for a single circuit: New York State Electric and Gas Company[64]

CRARYVILLE 400

	Interruptions		Customers Interrupted		Customer Hours of Interruption	
Tree In Row	7	11.48%	169	2.44%	619.503	4.29%
Tree Out Row	28	45.90%	3378	48.82%	4993.385	34.54%
Overloads	2	3.28%	229	3.31%	646.109	4.47%
Operational Errors	0	0.00%	0	0.00%	0	0.00%
Equipment Failures	7	11.48%	549	7.93%	207.464	1.44%
Accidents/Non-Utility	4	6.56%	1865	26.95%	6294.908	43.55%
Prearranged	1	1.64%	9	0.13%	19.647	0.14%
Customer Equipment	1	1.64%	1	0.01%	1.167	0.01%
Lightning	7	11.48%	531	7.67%	1242.753	8.60%
Unknown	4	6.56%	189	2.73%	430.749	2.98%
Totals	61	100%	6920	100%	14456	100%

Reliability performance data for worst-performing circuits provides standard reliability metrics and aggregate measurements of performance across all events, such as the total number of customers experiencing interruption. These data cover the reporting year and often include historical performance data, as well. Ameren Illinois, for example, provides SAIFI, CAIFI, and CAIDI for each worst-performing feeder for the three preceding years.[65] Appearing on the worst-performing list in previous years indicates continued performance issues, informing the selection of circuits for remediation.

Maintenance history data indicate whether a utility already has taken preventative or mitigation measures to improve circuit reliability. Commonwealth Edison, for example, reports the date of the most recent tree trimming and mainline and tap inspections (Figure 4-1).[66] These data help inform the extent of utility progress in addressing reliability issues for individual circuits and which circuits to prioritize for future maintenance.

4.2.2 Remediation Plans

Utilities develop remediation plans to mitigate worst-performing circuit reliability. Data can include the criteria for selecting the worst-performing circuits for remediation and details on specific remediation actions. Missouri, for example, requires remediation plans for "Multi-Year Worst Performing Circuits"—those that appear on the worst-performing list for any two of the three most recent consecutive calendar years.[67]

[64] New York State Electric and Gas, 2022 Annual Reliability Report, 2023
[65] Ameren Illinois, Response to 83 Illinois Administrative Code 411: 2022 Annual Report, 2023a
[66] Commonwealth Edison, *2022 ComEd Electric Power Delivery Reliability Report*, 2023a
[67] Missouri Code of Regulations, Title 20 4240-23.010, 2024

Detailed data on remediation actions includes specific actions that utilities have taken, and plan to take, as well as related timelines and cost estimates. Ameren Missouri, for example, provides a narrative description of its remediation efforts that relates specific actions (e.g., tree trimming) to the cause of interruptions (e.g., trees falling on lines).[68] As Figure 4-1 shows, Commonwealth Edison[69] reports total cost estimates for all planned and completed work. Planned work descriptions can range from high-level descriptions to technical specifications that include the length of lines added or the type and size of new transformers.[70] Utilities also can explain why they decided not to take action on any of the worst-performing feeders.[71] These details provide transparency on the strategies utilities pursue and demonstrate how utilities responded to known drivers of poor reliability performance. The information also provides a record of the utility's commitments to improve reliability for accountability purposes.

Utilities also can report on expected reliability improvements from planned remediation actions. California[72] requires that utilities provide a "quantitative description" of expected circuit reliability performance, though in practice much of the utility reporting provides qualitative assessments of reliability improvements.[73]

G6072 **Serving Customers in the Chicago Area - Source Substation: Alsip TSS60**

Engineering Analysis:

G6072 was a 1% CAIDI feeder in 2022 due to one event. The main driver for the activity was a primary wire down during a storm. Planned 1% work will create an overhead tie to reduce outage duration and replace primary wire and poles in poor condition.

Date of Last Tree Trimming	Last Inspection Date Mainline	Last Inspection Date Tap	Estimated Cost of Work	Additional Work Planned and/or Completed
4/20/2023	2/4/2023	2/4/2023	$168,800	Install tap fuse at 1 location, install disconnect at 1 location, install 2 poles, install wildlife protection at 2 locations, install approximately 350 feet of overhead wire, replace 2 poles, reconductor 1 span of overhead wire, replace overhead wire splice at 2 locations, and perform tree trimming as necessary.

Interruption Date	Customers Affected on Circuit	Duration in Minutes	Cause	Cause Detail
1/31/2022	4	190	Public	Dig-in by Others
	1	314		
9/2/2022	12	62	Public	Dig-in by Others
	5	228		
11/5/2022	1	1,116	Tree Related	Limb Broken - Primary
	65	1,125		

Figure 4-1. Worst-performing circuit event history, maintenance history, and remediation plan: Commonwealth Edison[74]

[68] Ameren Missouri, *20 CSR 420-23.010 Electric Utility System Reliability Monitoring and Reporting Submission Requirements – Annual Reliability report*, 2023

[69] Commonwealth Edison, *2022 ComEd Electric Power Delivery Reliability Report*, 2023a

[70] New York State Electric and Gas, *2022 Annual Reliability Report*, 2023

[71] Illinois Commerce Commission, Illinois Administrative Code, 83.1.c.411, 2022

[72] CPUC, Decision Updating the Annual Electric Reliability Reporting Requirements for California Electric Utilities, 2014a

[73] PG&E, *2022 Annual Electric Reliability Report*, 2023

[74] Commonwealth Edison, *2022 ComEd Electric Power Delivery Reliability Report*, 2023a

4.3 Best Practices

Best practices for sharing data on worst-performing circuits include:

- Describe reliability performance metric selection, interruptions excluded from metric calculation, and screening criteria applied to performance data to identify worst-performing circuits
- Provide detailed data on worst-performing feeders:
    - Identifying information for circuits and customers served, by customer class
    - Date, cause, and impact (e.g., customers interrupted, customer hours interrupted) for each reliability event in the reporting year
    - Multiple years of reliability performance metrics and aggregate measures of reliability (e.g., total number of interruptions)
    - Maintenance history (e.g., date of last inspection and tree trimming and description of preventative/mitigation taken in previous reporting years)
- Provide detailed information on remediation plans:
    - Criteria for determining which worst-performing circuits receive remediation plans
    - Description and costs of actions already taken in the reporting year to address poor performance
    - Description, cost, and timeline of actions planned to address poor performance

5. Asset Management Strategy

Asset management encompasses all of the ways utilities make decisions about building and maintaining distribution infrastructure. Asset management spans the full asset life-cycle, from initial equipment selection to design and construction practices to inspection and maintenance and, ultimately, replacement. Most utility infrastructure is expected to remain in service while being exposed to the elements for several decades, which makes both initial construction and ongoing maintenance practices critically important for long-term safe and efficient operation of the distribution system.

Common decision-making elements in executing an asset management strategy include the following:

- *Asset performance:* Assets must be capable of performing their intended function(s) and meeting all applicable codes and standards. For new assets, performance is an important factor in specifying equipment or construction practices. For existing assets, performance is a consideration for inspections and maintenance activities, particularly ensuring public and worker safety.
- *Reliability and resilience:* Maintaining and improving reliability and resilience are core goals for utility spending and, consequently, are central to effective asset management.
- *Efficient budgeting and allocation:* Fundamentally, effective asset management identifies and prioritizes necessary and beneficial activities that maximize benefits for customers while minimizing costs. Balancing short-run and long-run costs against a variety of system needs and potential improvements is the central challenge of asset management.

Asset management may or may not be addressed directly in utility distribution system plans, depending on state requirements and utility practices. In New York, for example, Distributed System Implementation Plans do not explicitly include asset management.[75] Minnesota, in contrast, has an explicit category covering standards, asset health, and reliability management.[76] Regardless of whether utilities provide direct data on asset management in distribution plan filings, underlying asset management practices and methods for selecting and prioritizing investments are important in optimizing resource deployment. Table 5-1 summarizes asset management data and its impacts on distribution system planning.

[75] See Joint Utilities of New York, Distributed System Implementation Plans, 2024 https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips.
[76] Minnesota Public Utilities Commission. Order, in Docket No. E-999/CI-17-879 et al., 2022

Table 5-1. Asset management data categories and impacts

Data category	Type of data reported	Impact of data on planning
Standards and guidelines	Equipment and design standards, engineering guidelines	Shapes physical grid infrastructure and types of solutions available to address system challenges
Asset and reliability data	Reliability indices, equipment testing and inspection data, device settings	Impacts distribution infrastructure and provides opportunities to coordinate asset management with distribution system planning to optimize spending on capacity upgrades
Programmatic asset-related investments	Utility programs and associated goals and budgets	
Discrete asset management investments	Asset needs identification and prioritization	

5.1 Data Inputs

5.1.1 Standards and guidelines: Equipment, construction, and design

Effective asset management starts even before any new equipment is placed in service. Equipment, design, and construction standards and guidelines are foundational to asset management efforts, as they ensure that assets are built in an optimal manner from the start.

Equipment standards and specifications dictate the specific performance requirements of the individual components that make up the distribution system. Specifications may include manufacturer or supplier documents or procurement-related materials used to source equipment. While most equipment specifications are not commonly included in utility distribution plans, they may be impactful to specific equipment replacement programs or grid modernization technologies. For instance, replacing porcelain cutouts with polymer cutouts is an emerging safety and reliability driver for utilities and may be included as part of the distribution plan or as a related investment. For instance, Xcel Energy included a Porcelain Cutout Replacement Program in its Integrated Distribution Plan based on safety improvements and reduction in customer outages expected to result from replacing porcelain cutouts with polymer versions (Figure 5-1).

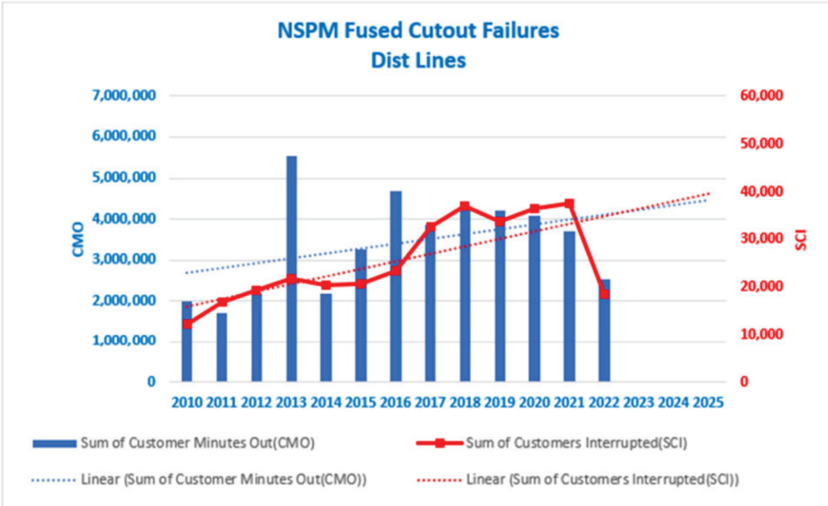

Figure 5-1. Xcel Energy fused cutout failure and customer outage data[77]

Construction standards are the methods and practices of the physical assembly and installation of distribution system equipment. Construction standards also include specific methods and practices for complying with the National Electrical Safety Code (NESC) and other applicable requirements. Specific construction standards are unlikely to be included in utility distribution plans, but broader system-level standards may be included, as they have broad impact on asset performance and cost. For example, Xcel Energy's *Integrated Distribution Plan 2204-2033* in Minnesota detailed the standardized use of NESC Grade "B" construction, which uses stronger poles to withstand more extreme ice and wind loadings.[78]

Engineering and design guidelines are far broader than equipment and construction standards. The guidelines are generally applied as a decision-making guide to balance factors such as cost, performance, and reliability for specific types of decisions across a utility's territory. Utility distribution plans often refer to specific engineering and design guidelines, as they are likely to be associated with new utility programs or changes to spending levels within existing programs. Following are examples of common utility engineering and design guideline topics.

- *Service Transformer Sizing:* Methods and assumptions for selecting service transformer sizes are based on customer load information. Many utilities are revisiting service transformer sizing calculations due to increasing adoption of solar and electrification, as well as increasing data availability through advanced metering infrastructure.
- *Underground Construction Utilization:* These are guidelines for selecting overhead or underground design for new construction in specific areas based on characteristics such as cost, reliability, maintenance, visual impact, or local requirements.
- *Underground Cable* – Repair or Replace: These guidelines are for responding to cable faults that indicate when a fault should be repaired or whether the cable segment should be replaced

[77] Xcel Energy, *Minnesota 2023 Integrated Distribution Plan 2024-2033* – Appendix A2, p 10–11, 2023
[78] Xcel Energy, *Minnesota 2023 Integrated Distribution Plan 2024-2033* – Appendix A2, p 12, 2023

instead. Factors influencing replacement decision-making may include the use of conduit, number of historical faults, accessibility, and replacement urgency.

- *System Voltage Standard Selection:* This guideline applies to the process and justification for standard voltage classes the utility uses for its distribution system. This guideline is included in distribution plans where the utility is pursuing long-term changes in system standard voltage as a result of load growth or standardization to facilitate circuit ties. One common example is converting legacy 4 kV distribution substations to 12 kV.
- *Voltage Conversion Make-Ready:* Where voltage conversion is a long-term goal, make-ready actions can reduce future conversion costs by deploying dual-voltage or higher voltage rated equipment. This may be utilized strategically, as dual voltage equipment is generally more expensive. The most common example is the installation of dual voltage transformers, which prevents the need for future replacement and simplifies the transition cutover process.
- *Storm Hardening:* These guidelines apply to design practices and equipment that provide additional strength or resilience to survive conditions beyond those anticipated and prescribed by the NESC.
- *Wildfire Prevention:* These are guidelines for the design and operation of utility equipment to reduce the risk of wildfires. Wildfire prevention also may be incorporated directly into utility design and construction standards. Common elements for wildfire prevention include use of covered conductors, use of underground equipment, and installation of advanced protective relaying capable of detecting downed conductors.

5.1.2 Data used in asset management decision-making

Because asset management is fundamentally focused on optimization, data related to asset health and performance is a critical input to decision-making. Equipment data, reliability data, and asset health data are all important inputs to analysis of programmatic and discrete investments in asset health. Many of these data streams are reported in utility distribution plans, as they often have wide-reaching impacts on utility budgets, planning, and operations.

5.1.2.1 Equipment data

The most foundational information for asset management is the equipment installed. Location, size, capabilities, age, and connectivity are all important records commonly kept by utilities that serve as the basis for asset management (among other critical activities). Data may be reported in utility distribution plans as aggregate counts of specific equipment such as poles, substations, transformers, or circuit miles of conductor. Utility line devices such as circuit breakers, reclosers, voltage regulators, load tap changers, and capacitor banks have programmable settings and associated utility records. These settings can have impacts on reliability, voltage management, and hosting capacity, among other distribution planning concerns.

5.1.2.2 Reliability and outage data

Asset management practices and investments have major impacts on reliability. Consequently, reliability and outage data are key inputs to making optimal decisions for asset management. Data provided in utility distribution plans may be at the systemwide or regional level, or may be available for specific circuits. Both sets of data are useful in understanding utility and asset performance. Data related to reliability may include metrics such as SAIFI, SAIDI, CAIDI (see Chapter 4: Worst-Performing Circuits for more information on outage metrics). DTE Electric's 2023 Distribution Grid Plan, for instance, included system-level SAIFI, SAIDI, and CAIDI data (illustrated in Figure 5-2) as well as outage cause data (illustrated in Figure 5-3).[79]

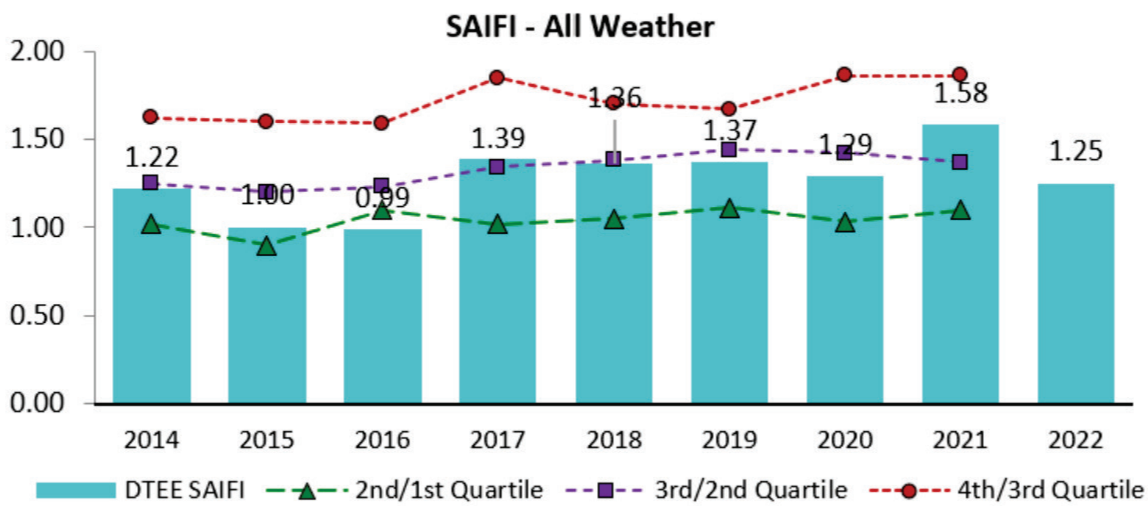

Figure 5-2. DTE 2023 Distribution Grid Plan, historical SAIFI data

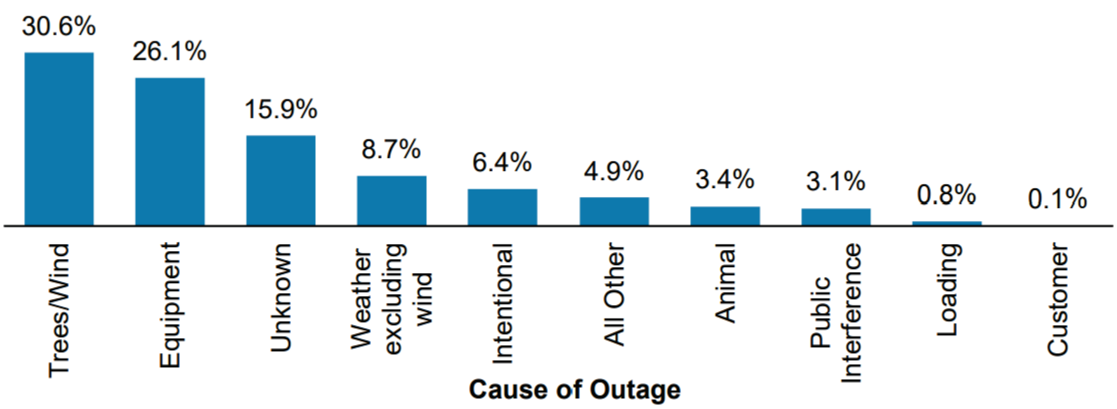

Figure 5-3. DTE Electric Company, 2023 Distribution Grid Plan, five-year average customer interruptions by cause (SAIFI)

5.1.2.3 Asset health data

Asset health refers to the relative risk of failure or nonperformance of a given asset. Because asset failure can have severe consequences impacting public and worker safety, environmental contamination, and reliability, it is generally desirable to replace assets before failure. Asset health data are useful in identifying which assets are at a higher risk of failure. Specific asset health assessment methods and data sources vary significantly depending on the type of equipment being considered, but

[79] DTE Electric Company, 2023 Distribution Grid Plan, pp. 39–41

the overall objectives are to prevent catastrophic failure and enable cost-effective scheduled replacement rather than responding to an emergency.

Most asset health testing and data collection is performed on an annual basis, either for all assets of a certain type or for a subset of assets based on a rotating multi-year schedule. For instance, capacitor banks may be inspected one or more times per year, while a given pole may be inspected every four to twelve years.

Assets that have relatively high costs are often a core focus of asset management programs. In particular, substation transformers, circuit breakers, and regulators are often inspected frequently and more thoroughly than line assets. Testing of the oil within transformers can be used to identify signs of insulation degradation that can indicate elevated failure risk, alongside a host of other testing methods. Other relevant data for health assessment may include asset age, historical loading data (especially whether and how often equipment ratings were exceeded), and the number of circuit faults downline that resulted in high magnitude fault currents. For breakers and voltage regulating equipment, the count of operations or tap movements also can be a strong indicator of health.

For assets that are relatively lower cost and installed at a high volume (e.g., poles), data availability is typically much more limited. Inspections are likely to be much less frequent and also generally do not provide the same degree of information. The frequency of inspections, data collected, and thresholds at which repair and replacement actions are taken are all important facets of asset management for high volume assets.

5.2 Data Outputs

5.2.1 Programmatic asset management investments

Given the scale of utility distribution systems and the high volume of physical assets, it is prudent to organize certain types of spending into programs covering specific activities with associated budgets. Programs that address repeating, ongoing needs are the most common programmatic investments for asset management. Utilities also can develop asset management programs that remediate widespread issues or deploy new technologies over a period of many years due to the cost and scale of deployment. It is relatively common for utilities to include program budget information, new program proposals, or information about changes to existing programs in their distribution plans.

Common utility programs for asset management and grid modernization include:

- Asset Inspections (poles, vaults, manholes, infrared, etc.)
- Animal Guarding and Avian Protection
- Forestry and Tree Trimming
- Underground Cable Replacement
- Lightning Protection
- Porcelain Cutout Replacement
- Communications and Sensor Deployment
- Voltage Optimization
- Advanced Metering Infrastructure Deployment

When considering the scope and budget for new or existing programs, prudency and cost-effectiveness are central concerns. It can be difficult to assess whether program spending is reasonable because the benefits or avoided risks may be spread across wide areas of the distribution system. Consequently, clear information on the drivers of programmatic investments and associated costs are critical factors to evaluate. It also is important to understand how to assess the effectiveness of a given program, including any specific metrics to be used for tracking program impacts.

5.2.2 Discrete asset management investments

In contrast to programmatic investments, discrete asset management investments generally capture specific projects at specific locations that are identified and justified based on reliability, asset health, or safety. Asset management drivers also may contribute to the justification of other system investments, such as distribution planning investments intended to increase capacity. Spending for different types of discrete asset management investments may be aggregated into categories (Table 5-2).

Table 5-2. Capital Expenditure Categories in Xcel Energy (Minnesota) 2023 Integrated Distribution Plan (2023-2027 – $M)

	Bridge Year	Budget					Budget Avg
IDP Category	2023	2024	2025	2026	2027	2028	2024-2028
Age-Related Replacements and Asset Renewal	$136.9	$179.4	$199.6	$231.2	$252.7	$272.4	$227.1
New Customer Projects and New Revenue	$50.1	$44.9	$47.6	$49.2	$51.1	$53.5	$49.3
System Expansion or Upgrades for Capacity	$35.8	$61.8	$93.2	$159.0	$193.3	$227.1	$146.9
Projects related to Local (or other) Government-Requirements	$29.2	$37.2	$39.6	$40.6	$41.6	$43.3	$40.4
System Expansion or Upgrades for Reliability and Power Quality	$40.9	$38.7	$55.4	$76.4	$201.2	$328.0	$139.9
Other	$70.8	$74.1	$55.1	$54.8	$56.4	$63.4	$60.7
Metering	$5.3	$4.1	$4.4	$4.7	$4.6	$4.5	$4.5
Grid Modernization and Pilot Projects	$115.4	$111.3	$56.3	$40.9	$33.5	$10.8	$50.6
Non-Investment	($2.1)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)
Electric Vehicle Programs	$9.3	$8.9	$1.4	$18.4	$36.9	$71.8	$27.5
TOTAL	$491.7	$556.5	$548.5	$671.2	$867.2	$1,070.7	$742.8

Utilities generally justify discrete projects individually based on local conditions and investment drivers. As a result, spending within categories can fluctuate year to year based on actual system needs. Consider a substation transformer where routine testing determines that the asset is at a very high risk of failure. The replacement of the transformer may be categorized under “asset renewal” or a similar category, but the spending is driven by the specific needs so it’s appropriate to justify it accordingly.

Programmatic investments, in contrast, generally cover a larger geographic area—many are systemwide—and are justified based on aggregate benefits and costs.

Utilities have many different methods for justifying both discrete and programmatic investments related to asset management. Generally, these methods focus on demonstrating the degree of need relative to the cost. That can be used as justification for specific investments or to prioritize a set of proposed investments to maximize benefits. Benefit-cost analyses are a common tool for this purpose. Many utilities also are adopting software tools for asset management and portfolio management that are capable of quantifying value drivers for various investments for prioritization. For example, Ameren Illinois' *2023 Multi-Year Integrated Grid Plan*[80] used the Copperleaf platform[81] (Figure 5-4) for this purpose.

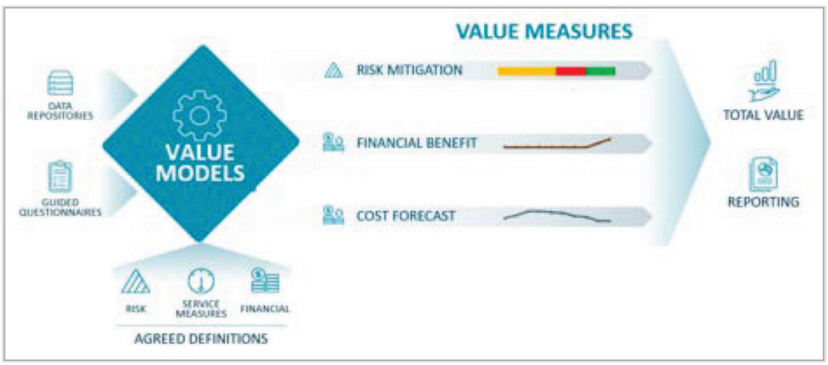

Figure 5-4. Ameren Illinois Multi-Year Integrated Grid Plan Copperleaf value models

5.3 Best Practices

Best practices for sharing data on asset management include:

- Clearly identify standards used to assess asset condition.
- Provide data for programmatic asset management investments to validate that the program is having the intended level of impact.
- Provide data for new programmatic investments to demonstrate the need for the program as well as data that can be reported to demonstrate the program's effectiveness.
- Be transparent about how the utility evaluates asset health and determines when to replace aging assets to provide clarity and support regulatory oversight.
- Share equipment selection and design practices, especially where practices are changing as a result of evolving system needs or environmental conditions, to facilitate efficiency across the anticipated useful life of constructed assets.

80 Ameren Illinois, *Ameren Illinois' Refiled Multi-Year Integrated Grid Plan*, 2024a
81 See https://www.copperleaf.com/.

6. Hosting Capacity Analysis

Hosting capacity is the amount (capacity) of DERs, most commonly distributed PV, that can be interconnected to the distribution system without infrastructure upgrades or adversely impacting power quality or reliability under existing control and protection systems. Hosting capacity analysis (HCA) models existing grid conditions and simulates power flow at various levels of DER penetration to determine hosting capacity for generation, battery storage, or new loads such as EV charging.

Hosting capacity maps can serve as a guide for distributed PV developers to evaluate potential project sites. Utilities can use HCA to determine if detailed studies are necessary for interconnection processes. Utilities also can use HCA in distribution system planning to identify the location and causes of distribution system constraints and assess options to mitigate them. In addition, HCA can support estimates of the locational value of DERs.

Key input data for HCA that utilities can share with regulators and stakeholders in the distribution planning process include descriptions of HCA analytical frameworks, distribution system infrastructure attributes, load characteristics, and DER capacity (Table 6-1). Outputs that utilities can share include estimates of hosting capacity for generation, load, and storage as well as results of mitigation analyses.

Table 6-1. Hosting capacity data and impacts on planning

Data category	Type of data reported	Impact of data on planning
Analytical framework	Criteria for updating HCA and key methodological decisions	Provides transparency and enables regulators to validate utility decisions and propose alternatives
Distribution system infrastructure attributes	Locational, technical, and operational information on substations and feeders	Informs siting of DERs and loads absent power flow simulations
Load characteristics	Peak and minimum demand	Informs siting of DERs and loads
DER capacity	Installed and queued DER capacity	Informs siting of DERs and loads
Hosting capacity estimates	Generation, load, and storage hosting capacity	Informs siting, sizing, and operations of DERs and EV charging stations
Mitigation analysis	Options and costs for mitigating constraints	Provides transparency, enables validation of utility analyses, and provides insight into utility investment decisions and potential alternatives

6.1 Data Inputs

6.1.1 Analytical framework

Utilities can document HCA methodological decisions in distribution system plans and describe the costs and criteria for updating their HCA processes. Methodological decisions may include the types of hosting capacity constraints considered, criteria used for identifying each constraint, maximum DER calculation size, and modeling tools used.

Hosting capacity constraints can reflect voltage, loading, and system protection, and inform what changes to project design and what system upgrades are necessary to resolve constraints.[82] For example, Table 6-2 shows criteria that ComEd uses to determine constraints, including a simple description of the criteria that helps nontechnical audiences understand their importance, specific threshold values, and the basis for each constraint. Transparency on the thresholds used for determining constraints enables regulators and stakeholders to understand utility analyses and propose alternatives if relevant.

Table 6-2. ComEd criteria for determining hosting capacity constraints[83]

Criteria	Description	Threshold	Basis
Abnormal Voltage (over voltage)	Voltage exceeds nominal voltage by threshold	105%	Maintain allowable voltage limits per IL Administrative Code Section 410.300
Voltage Variation (Flicker)	Change in Voltage from no DER to full DER (ON/OFF)	3%	Maintain power quality for customers. Eliminate significant voltage fluctuations which may affect power quality to nearby customers and equipment.
Thermal Loading	Element rating	100%	Exceeding these limits would cause equipment to potentially be damaged or fail.
Reverse Power Flow	Reverse Power Flow at voltage regulators and feeders.	0%	Not allowed at voltage regulators and feeder heads to prevent mis-operation due to bi-directional control limitations.

Maximum DER calculation size refers to the amount of DER at which the hosting capacity calculation process will no longer continue to add DERs at a given location. For example, DTE Energy established a maximum calculation DER size of 2 MW.[84] A relatively common maximum size cutoff for medium voltage (e.g., 12.47 kV) distribution systems is 10 MW. Ameren Illinois[85] and Xcel Energy,[86] among others, use this threshold. These caps establish the upper limit for hosting capacity at a given location. DERs larger than this size may still apply for interconnection, but will have more limited information available from the hosting capacity map.

82 Xcel Energy Minnesota, 2022 Hosting Capacity Program Report, 2022
83 ComEd, Multi-Year Integrated Grid Plan, 2023
84 DTE Energy hosting capacity map, n.d.
85 Ameren, Ameren Illinois Refiled Multi-Year Integrated Grid Plan – Hosting Capacity, p 235, 2024b
86 Xcel Energy, 2024 Hosting Capacity Program Guidebook, 2024

Utilities can identify and describe the tools they use in HCA. In its 2023 Integrated Distribution Plan in Minnesota, Xcel Energy provided a table that maps tools to planning activities, including HCA, and explains the capabilities and uses of each tool.[87] Such information helps regulators and stakeholders understand workflows and relate utility practices to industry best practices. The choice of software tool can impact the use cases that HCA can enable. For example, tools with stochastic modeling capabilities add incremental DERs of varying sizes at varying locations within the model until hosting capacity criteria are violated and then repeat this many times using Monte Carlo analysis. While stochastic modeling tools provide useful information for distribution planning, such as a wide range of possible outcomes, including those related to DER adoption, and the likelihood of various scenarios occurring, other tools can better support interconnection-focused use cases. Tools with iterative modeling capabilities, which add increments of DERs at a specific location until hosting capacity criteria are violated (repeated for all locations), can provide information much more geared toward supporting interconnection.[88]

Given the effort required, utilities may update HCA for only a subset of feeders each year. In HCA reports, utilities can describe the criteria used for selecting feeders for updates. Xcel Energy,[89] for example, includes feeders in quarterly HCA updates if the feeder's hosting capacity has not been updated in the previous 12 months and one of the following criteria is met:

- Load has increased or is expected to increase by 500 kilovolt-amperes (kVA) within one year
- Newly installed DER capacity totals at least 100 kW
- Feeder capacity or configuration has changed or will change due to projects in the next year

Providing such transparent criteria helps regulators and stakeholders know what HCA updates to expect and facilitates consideration of alternative criteria.

In addition, utilities can report the cost to update HCA. Pursuant to an order from the Minnesota PUC, Xcel Energy's 2022 hosting capacity report provides estimates of staffing costs if the utility updated HCA monthly using its existing process, compared to the net cost of modeling upgrades considering labor cost savings through automation.[90] Such detailed cost data can help regulators determine whether modeling upgrades may be appropriate. That includes consideration of expanded HCA functionality, such as its use for interconnection, one of the motivations for consideration of monthly updates in Minnesota.[91]

6.1.2 Distribution system infrastructure attributes

Table 6-3 summarizes the characteristics of substations and feeders that utilities can report in hosting capacity maps and downloadable tables. Utilities use these data as inputs to simulations of the

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87 Xcel Energy, Integrated Distribution Plan, Table A1-2, 2023a

88 Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021

89 Xcel Energy Minnesota, 2022 Hosting Capacity Program Report, 2022

90 Xcel Energy Minnesota, 2022 Hosting Capacity Program Report, 2022

91 Xcel Energy Minnesota, 2022 Hosting Capacity Program Report, 2022

distribution system to estimate hosting capacity values. The data also can inform siting of DERs before a utility performs power flow simulations.[92]

Table 6-3. Substation and feeder characteristics[93]

Characteristic	Substation	Feeder
ID/name	X	X
ID/name of substation/feeder it is connected to	X	X
Location (coordinates)	X	X
Count of substation transformers	X	
Number of customers by customer class	X	X
Has known transmission constraint	X	X
Recent upgrades	X	X
Planned upgrades	X	X
Voltage(s)	X	X
Transformer nameplate rating	X	X
Has protection/regulation	X	
Has been upgraded for reverse flow	X	
Bus-tie exists	X	
Type (e.g., radial, network, mesh, spot)		X
Length		X
Voltage		X
Number of phases		X
Conductor capacity		X
Service transformer rating		X

6.1.3 Load characteristics

Utilities can provide data on minimum and peak demand for locations of the distribution system for which they are estimating hosting capacity. Minimum demand values vary by hour of the day (daytime vs. all hours) and time period (year vs. month). Daytime minimum demand, whether annual or monthly, can inform PV site selection and operation because generation during periods of low demand are more likely to cause voltage or other issues. Providing daytime minimum demand on a monthly basis can enable PV or other DER projects that can adjust exports to the grid throughout the year. Annual

[92] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
[93] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021

reporting provides the minimum load data from the month with the lowest demand.[94] Increasing the granularity of hosting capacity data can facilitate improved DER sizing for applications.

Providing minimum demand data for all hours in a day can inform siting of battery storage paired with PV as well as distributed generation technologies that, unlike PV, can produce power outside of daytime hours.[95] For example, Xcel Energy in Minnesota provides both daytime and absolute minimum demand in its hosting capacity map, enabling developers to make informed decisions about siting, sizing, and operating distributed generation and storage technologies.[96]

Historical and forecasted peak loads can inform site selection for new loads such as EV charging. For example, Con Edison provides peak load (MW) in its load hosting capacity map, and Rhode Island Energy provides peak load for the previous year and for 10 years forecasted into the future.[97] [98]

Instead of single-hour demand values such as minimum and peak load, utilities can share an hourly load profile for an entire year (8,760 hours), load profiles for the two days in each month when peak and minimum demand occur (576 hours), or monthly peak and minimum load values. San Diego Gas & Electric (SDG&E), for example, provides monthly peak and minimum load values within its Integration Capacity Analysis tool (Figure 6-1).

Figure 6-1. Monthly peak and minimum load chart example – SDG&E[99]

6.1.4 DER capacity

HCA data for DERs can include installed and queued generation capacity or the number of applications in the study queue. Such information indicates the penetration of DERs in that area, as well as the

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[94] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
[95] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
[96] Xcel Energy, Minnesota, hosting capacity map
[97] Con Edison, Hosting Capacity Web Portal
[98] Rhode Island Energy, System Data Portal
[99] SDG&E, Interactive Map and ICA User Guide

potential timeline for queued studies still to be processed. Figure 6-2 shows how DTE Energy indicates the queued and installed DER capacity in its hosting capacity map.[100]

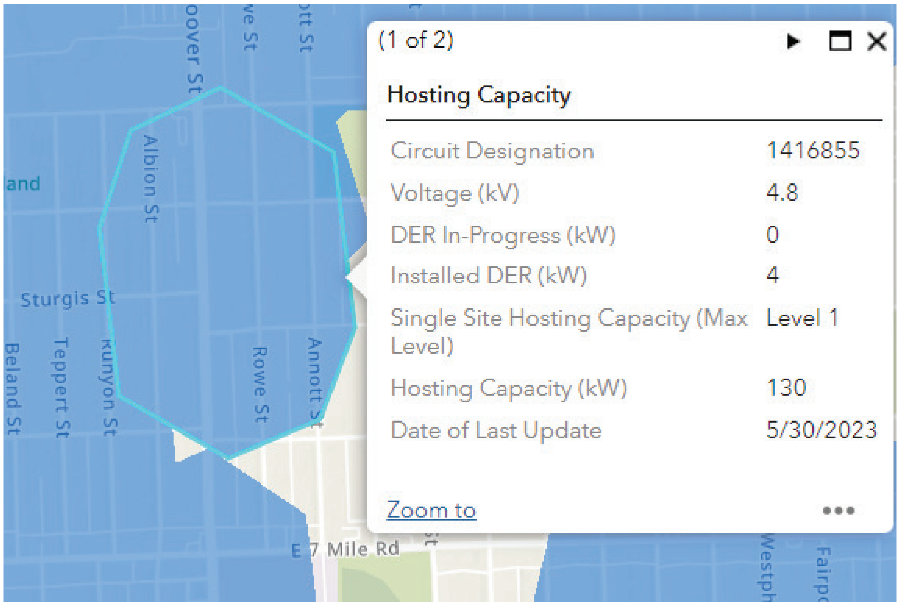

Figure 6-2. Queued and installed DER capacity in DTE Electric Company hosting capacity map

6.2 Data Outputs

6.2.1 Hosting capacity estimates

Utilities can provide hosting capacity estimates for generation, load, and energy storage. Utilities can publish these data in maps (see Figures 6-2 and 6-3), which can reduce the volume of data requests to utilities and help developers and customers access data relevant to their projects. Downloadable tabular data can complement the maps and can support analysis. Xcel Energy, for example, provides feeder and node level results in a machine-readable tabular format.[101] Central Hudson, while not providing direct downloadable tabular versions, enables tabular export of data using built-in ESRI map capabilities.[102] Application programming interfaces, such as those hosted by Con Edison and other New York investor-owned utilities, also can support analysis and help developers incorporate hosting capacity data into their own processes.[103] [104]

Similarly, utilities can share geographic data underlying HCA maps, which project developers can incorporate into their own geographic systems.[105] Utilities can report each type of hosting capacity for nodes within the feeder's footprint (Figure 6-2) or at the feeder level (Figure 6-3). Sub-feeder-level

100 DTE, Energy hosting capacity map
101 Xcel Energy, Hosting Capacity Resources, https://mn.my.xcelenergy.com/s/renewable/developers/interconnection.
102 Central Hudson, Hosting Capacity Map
103 Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
104 Con Edison, REST Services Directory
105 Con Edison, REST Services Directory

data can support more targeted deployment of DERs and help developers assess specific interconnection points.

Figure 6-2 is a [hosting capacity map for Xcel Energy in Colorado](). For this feeder node, unintentional islanding is the most constraining hosting capacity criteria to 0.47 MW. The overvoltage criteria is the “maximum” because it is the last constraint to be violated during the iterative hosting capacity calculation process. In this example, 10 MW is the maximum DER size considered within the study and does not necessarily result in a violation of the overvoltage criteria. Transparency into the factors that constrain hosting capacity helps developers understand whether and which system upgrades will be necessary to enable DER projects of varying sizes.

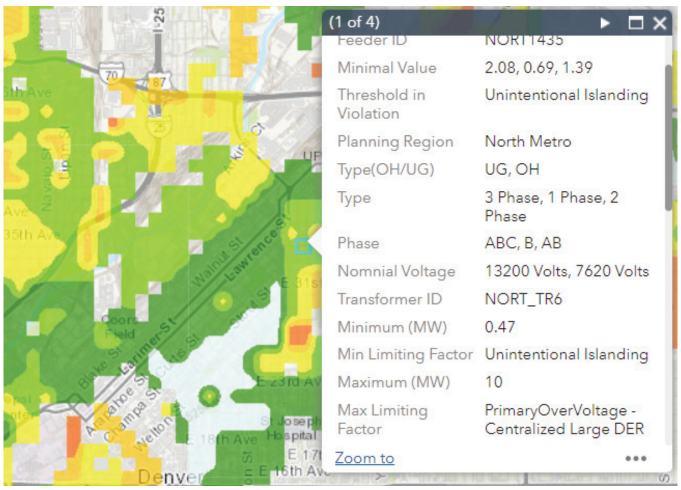

Figure 6-2. Xcel Energy, Colorado generation hosting capacity map and data pop-up window

Load hosting capacity data can include capacity available for EV charging, as well as building electrification. For example, Con Edison provides load hosting capacity for transformers and feeders for both EV charging and building electrification (Figure 6-3).[106] Hosting capacity values for individual service transformers inform site-level restrictions, and feeder and substation hosting capacity values for both summer and winter support decisions for larger developments. The utility’s hosting capacity values represent the difference between seasonal peaks and rated capacity of the equipment.

Hosting capacity varies by season due to differences in load and equipment capacity. At colder temperatures, loading capacity of distribution system infrastructure increases. Load hosting capacity maps can show specific values for feeders and transformers (the lines and circles in Figure 6-3) or provide ranges (e.g., 0.5–1 MW).[107] Ranges can be helpful guides, but specific hosting values for distribution system equipment better support decision-making.

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106 Con Edison, Con Edison Hosting Capacity Web Application
107 Delmarva Power, Available Load Capacity Map

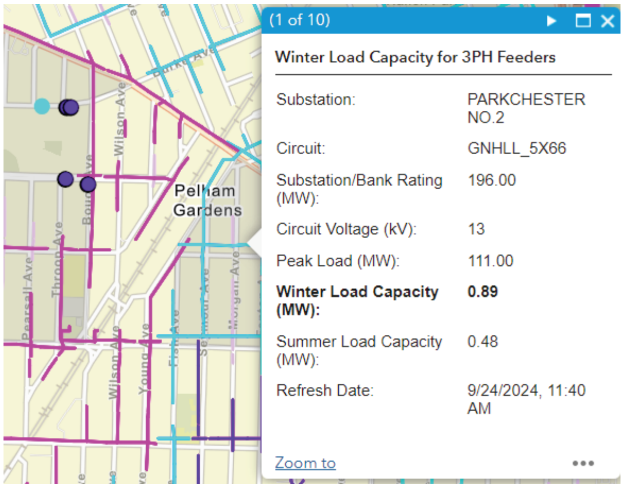

Figure 6-3. Con Edison load hosting capacity map and data pop-up window[108]

New York investor-owned utilities are among the few U.S. utilities that provide hosting capacity information for energy storage systems.[109] These New York utilities publish hosting capacity maps for storage separately from those for generation and load hosting capacity. Orange & Rockland Utilities, for example, publishes a map with hosting capacity for both storage charging and discharging.[110]

For all types of hosting capacity results, utilities can report the date that they last updated the data (see Figures 6-1 and 6-3). The more recent the data, the less likely a developer will confront unforeseen issues due to changes in distribution system components, load, or installed capacity of distributed generation or storage at the intended point of interconnection.

Utilities also can report data on HCA accuracy. For example, the California Public Utilities Commission recently required Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison to provide biannual HCA reports that identify issues with HCA accuracy or data completion and describe plans and timelines for correcting the issues.[111] Discrepancies between HCA and interconnection study results for specific loads or DERs also can point toward potential improvements.

6.2.2 Mitigation analysis

Mitigation analysis identifies constraints to hosting capacity and considers strategies to address these constraints. Utility HCA reports can delineate mitigation options and costs and provide estimates of increased hosting capacity that result from mitigation. Xcel Energy in Minnesota, for example, summarized potential mitigation strategies to address a range of common constraints for generation hosting capacity (Table 6-1). Such documentation provides transparency into the utility's decision-making process and helps regulators and stakeholders understand options available for increasing hosting capacity. The utility also reported the range of costs for mitigation and interconnection for DERs

[108] Con Edison, Con Edison Hosting Capacity Web Application
[109] DOE, Atlas of Electric Distribution System Hosting Capacity Maps
[110] Orange & Rockland Utilities, Hosting Capacity Web Application
[111] CPUC, Rulemaking 21-07-017, 2024

1–5 MW ($50,000–$1.4 million), noting that it is generally less costly to manage voltage constraints by adjusting inverter settings than to mitigate thermal issues.[112] Such cost information can help regulators and stakeholders understand which constraints to prioritize with limited resources and help developers understand expected utility system upgrade costs when different types of constraints are exceeded.

Table 6-1. Xcel Energy, Potential Mitigations to Increase Generation Hosting Capacity[113]

Category	Impacts	Mitigation
Voltage	Over-voltage	Adjust DER power factor setting, reconductor
	Voltage Deviation	Adjust DER power factor setting, reconductor
	Equipment Voltage Deviation	Adjust DER power factor setting, adjust voltage regulation equipment settings (if applicable), or reconductor
Loading	Thermal Limits	Reconductor, replace equipment
Protection	Additional Element Fault Current	Adjust relay settings, replace relays, replace protective equipment
	Breaker Relay Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment
	Sympathetic Breaker Relay Tripping	Adjust relay settings, replace relays, move or replace protective equipment
	Unintentional Islanding	Installation of Voltage Supervisory Reclosing

6.3 Best Practices

Best practices for sharing data on hosting capacity analysis include:

- Identify the maximum DER size considered in the analysis
- Document types of constraints considered and the threshold for each constraint
- Publish publicly-available maps that present node-level data on:
    - Substation and feeder characteristics
    - Installed and queued DER capacity
    - Historical and forecasted peak demand
    - Daytime and absolute minimum demand
    - Generation, load, and energy storage hosting capacity
    - Underlying geographic information
    - The constraint that limits hosting capacity
    - Date of last update
- Document issues with hosting capacity accuracy and plans to correct those issues
- Offer a tabular version of mapped data or an application programming interface that enables access to the data in a usable form
- Identify strategies and costs to mitigate hosting capacity constraints, including no- and low-cost options
- Describe criteria and costs for updating modeling tools and capabilities and updating hosting capacity analysis on a more frequent basis

[112] Xcel Energy, Minnesota, Reply Comments to 2019 Hosting Capacity report, 2019

[113] Xcel Energy, 2024 Hosting Capacity Program Guidebook, Table 3

7. Value of Distributed Energy Resources

Value of DER, as a concept, is an attempt to more accurately account for the benefits of DERs to the power system, especially at the distribution system level where there are no existing market structures. One of the objectives of valuing DERs in distribution planning is to direct DER deployment to areas that improve distribution system outcomes or prevent or defer future investments.

Currently, implementation of rates and compensation structures based on the value of DERs is limited. The majority of the work to date has been in the form of state-level value of DER studies, which attempt to quantify the value of different types of benefits such as capacity, loss reduction, and voltage support.

Valuing DERs is an important building block for enabling these resources to provide distribution services and be effectively compensated. It is particularly critical for energy storage, where there is significant potential value that is not realized or effectively compensated by traditional Net Energy Metering frameworks. Whether and how DER value is considered, calculated, and incorporated is part of a broader consideration of how DERs are integrated in distribution planning and investment processes.

Generally, DER value is derived by quantifying costs that are avoided as a result of the expenditure that would otherwise be incurred by the utility. Other benefits also may be included, with magnitudes based on the cost to achieve the benefits using other available means. Fundamentally, valuing DERs aims to provide utilities with another way to meet system needs, and is thus closely tied to key distribution system planning (DSP) elements, including distribution system planning, load and DER forecasting, and investment justification. Table 7-1 summarizes value of DER data that can be included in distribution system plans and its impacts on planning.

Table 7-1. Value of DER data categories and impacts on planning

Data category	Type of data reported	Impact of data on planning
Distribution system input data	Distribution growth expectations, capacity needs, and historical costs	Informs DER programs, which can affect future distribution system planning needs
DER input data	DER types and associated performance characteristics	
Distribution DER value drivers	Value drivers considered and corresponding quantification methodologies	

7.1 Data Inputs

Value of DER studies can cover one or more types of DERs active in a utility's distribution system. Single-technology studies can reduce study complexity and address specific planning needs. For example, a Value of Solar study was performed for the Minnesota Department of Commerce[114] to inform a Value of Solar tariff for investor-owned utilities.[115] However, studies capturing only one technology type may use methods or assumptions that can be difficult to generalize or apply more broadly because specific performance characteristics of the technology (e.g., solar resources producing energy during daylight hours) are embedded within the process. Technology-agnostic studies, in contrast, use generalized methods that provide a flexible base to which different types of DER and performance characteristics can be applied to determine the value of a specific type of DER.

Regardless of the set of DER technologies studied, utilities can report on performance characteristics of each DER, including the operating profile, use of autonomous smart inverter functions, lifespan, and monitoring and control capabilities. These characteristics have a significant impact on the value calculations performed in the study and the ability of a DER to provide value after installation.

Operating profiles describe the timing and magnitude of DER electricity resource production, consumption, or storage. For solar PV, utilities can provide a time series of expected power generation and document data sources. For example, a 2022 New Hampshire study[116] used ISO-New England production profile data with NREL's PVWatts[117] generation profiling tool.

Because distribution needs are often limited to specific hours of the year (e.g., hours of peak load), the timing and magnitude of DER operation within the operating profile have significant impacts on the resulting value. For event-driven DERs such as demand response, utilities may identify the specific program or control mechanism that will be used to align DER performance with local needs. Central Hudson's Peak Perks Program in New York[118] provides one such example. Because distribution needs vary in time and may not fully coincide with bulk power system needs, aligning DER performance is critical to providing distribution system value.

Autonomous smart inverter functions can impact overall performance and DER value by providing additional voltage support. DERs with volt/volt-amps reactive (VAR) curve functionality are particularly effective, as they can modify their reactive power setpoint in response to local voltage conditions to help mitigate voltage violations. Volt/watt curves also may be used to address overvoltage challenges, but they involve greater risk of real power curtailment and subsequently are less commonly used. For example, New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E) require the volt/VAR curve points in Table 7-2, but do not use volt/watt functionality. Utility reporting on smart

114 Norris, Putnam, and Hoff, *Minnesota Value of Solar: Methodology*, 2013

115 State legislation enabled use of the tariff as an alternative to net metering and as a rate that can be used for community solar gardens.

116 Dunsky Energy + Climate Advisors, *New Hampshire Value of Distributed Energy Resources: Final Report*, No date

117 NREL, PVWatts® Calculator

118 Central Hudson, Peak Perks

inverter functions using the associated curve points help regulators and stakeholders understand how DERs can support voltage and corresponding value.

Table 7-2. NYSEG and RG&E Volt/VAR Curve[119]

Volt-VAR[2]

Volt-VAR Active	Yes
Vref	1
V1 - [pu]	0.93
Q1 - %Nameplate Apparent Power Rating	0%
V2- [pu]	0.97
Q2 - %Nameplate Apparent Power Rating	0%
V3 - [pu]	1.03
Q3 - %Nameplate Apparent Power Rating	0%
V4 - [pu]	1.07
Q4 - %Nameplate Apparent Power Rating	-44%

[2] (+) Q Values Indicate Injection of Reactive Power (VARs) from the Inverter onto the Area EPS (-) Q Values Indicate Absorption of Reactive Power (VARs) from the Area EPS to the Inverter

The time period considered in Value of DER studies is another critical aspect that can significantly influence value calculations. The period may be aligned with forecasting time horizons for utility distribution system plans (e.g., five to ten years) or with the expected DER lifespan for longer-term value considerations. A recent study for the District of Columbia Public Service Commission,[120] for example, incorporated valuation estimates through 2045. Considering longer time horizons tends to increase the resulting calculated value because DERs provide services for additional years. Because the studies rely on forecasts and assumptions, however, adding years further into the future also tends to increase the risk of inaccuracies.

The ability to collect and use real-time and historical performance data in planning processes can reduce the number of assumptions, which often reflect worst case scenarios. Replacing assumptions with actual data leads to a more accurate understanding of system needs and improves investment efficiency. The ability of utilities to directly control solar generation and storage, for example, to align DER operations with local grid needs can enable much more effective use of DERs as a capacity resource. Hawaiian Electric's Bring Your Own Device Program[121] enables a variety of customer resource types, including battery storage systems and smart thermostats, to be dispatched by the utility to align with distribution and bulk power system needs for capacity.

119 NYSEG and RG&E IEEE 1547-2018 Default Smart Inverter Settings, 2023
120 Kallay, J. et al., *A Value of Distributed Energy Resources Study for the District of Columbia: Framework, Impacts, Key Findings, and Roadmap*, 2023
121 Hawaiian Electric, Bring Your Own Device Program, 2024

7.1.1 Types of DER value and services to the distribution system

Utilities can identify the specific drivers they consider, describe the method(s) by which the value can be quantified, and report calculated values. Table 7-3 defines the types of values utilities can report in distribution system planning.

Table 7-3. Types of values utilities can report for value of DER studies and distribution system plans

Value driver	Definition
Distribution capacity	DERs delay or avoid the need for distribution capacity upgrades by reducing peak demand.
Loss reduction	When generated energy is consumed locally, DERs can reduce energy lost in electricity transmission and distribution.
Voltage support (power quality)	DERs can increase local voltages in low voltage areas and help modulate voltages using smart inverter functions.
Increased hosting capacity	DERs capable of acting as controllable loads can absorb excess solar generation, allowing for additional solar energy to be generated or additional distributed PV systems to interconnect.
Reliability, resilience, and outage reduction	Certain types and configurations of DERs can act as an alternate source during system outages, improving reliability and resilience.
Operations and maintenance (O&M) spending reduction	Utilities engage in a wide range of operations and maintenance activities that may be positively impacted by DERs.
Asset health	DERs can reduce the loading on equipment, which may increase equipment lifespan or reduce failure risk.
Other DER impacts	DERs may have positive impacts across nontechnical considerations including societal, environmental, and other benefit streams.

Specific services and methods vary by jurisdiction and study methodology. Distribution capacity is the most common DER service considered. Utilities can calculate distribution capacity value of DERs in either the short-run or long-run. *Short-run capacity value* refers to specific capacity upgrades expected to be necessary at specific locations within the utility's distribution planning forecast time horizon (e.g., 5–10 years). DER value for such locations is based on the magnitude of the capacity investment and the number of years it can be deferred through DER-derived capacity. *Long-run capacity value* refers to capacity-related investments that may become necessary but are not currently included in the forecast. These types of capacity needs may result from deviations from the utility forecast or occur beyond the forecast window. Whether the utility uses short-run or long-run values, or both, when determining distribution capacity value significantly affects the magnitude and locational nature of any resulting customer incentives.

Other potential value drivers span system efficiency, reliability, power quality, and maintenance, among others. Specific methods for quantifying and incorporating these value streams are still nascent, as they tend to be even more location-driven than capacity and often have less supporting information available to quantify the potential DER impacts.

Figure 7-1 illustrates Commonwealth Edison's marginal cost of service study process for its Grid Plan. Table 7-4 provides marginal cost results from Ameren Illinois' Grid Plan for a range of assumptions.

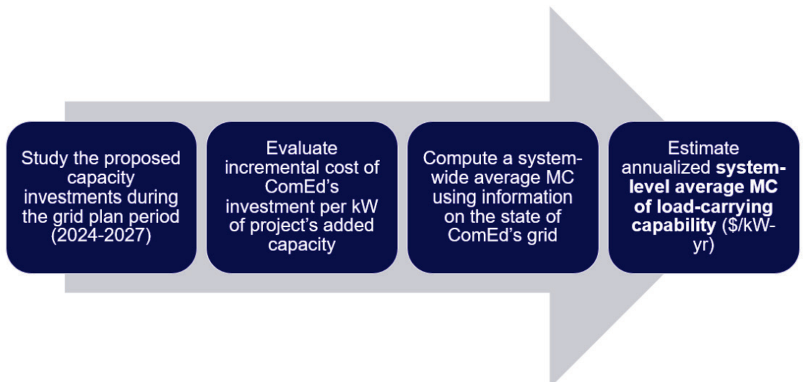

Figure 7-1. Commonwealth Edison's marginal cost of service study methodology[122]

Table 7-4. Ameren Illinois marginal cost results[123]

Marginal Cost Analysis (2023 Dollars)	Low Range	Mid Range	High Range
Total capacity-related annualized marginal cost ($/kW-year)	$6.81	$11.46	$21.75

Reduced line losses

When energy produced by DERs is consumed locally, it does not travel across transmission and distribution infrastructure components. That reduces energy losses and associated costs. When energy produced by DER is exported to the utility system, impacts to energy losses are more complex to evaluate and depend on local system loads and configurations. Changes in energy losses due to DERs are an important consideration in assessing DER value. It is difficult to assess these changes at a system level, given the high degree of variation in DER location. Modeling at a smaller scale and analytical calculations can provide estimated results for various locations.

Voltage support

Utilities can use DER real and reactive power capabilities to help regulate distribution system voltages and prevent voltage conditions outside of the standard operating range. Smart inverter capabilities

[122] ComEd, ComEd Refiled Grid Plan - Chapter 5: Hosting Capacity and Interconnection Investments, p 50, 2024. The study resulted in a marginal cost per kW of peak load of $5.54/kW-year.
[123] Ameren Illinois, *Ameren Illinois' Refiled Multi-Year Integrated Grid Plan,* Appendices P-W, p. 136, 2024c

such as volt/VAR curves are particularly impactful at providing voltage support. Because DERs also can create voltage issues, DER value analysis can identify voltage issues are “self-inflicted”—those result from DER operations—and separate them from system-driven voltage issues where DERs are providing only positive support.

Quantifying the value of voltage support from DERs is often difficult. First, utility historical data on voltage violations is often limited to customer complaint information. Advanced metering infrastructure measurements that include meter voltage provide an opportunity to examine the location, frequency, duration, and severity of voltage violations, but even with these data available there are challenges to ensuring accuracy and consistency. Second, performance of DERs varies, and they may not be fully capable of replacing traditional voltage management equipment (voltage regulators or capacitor banks) if the DER (e.g., solar) is not producing during some periods of voltage violation.

Increased hosting capacity

Battery storage, when operated for such a purpose, can charge from excess solar capacity and discharge to the grid during periods of higher load, effectively increasing hosting capacity. Voltage support and data access also can increase hosting capacity. Analysts can take care not to include benefits for avoiding constraints that the DERs themselves otherwise might cause.

Reliability, resilience, and outage reduction

The ability of DERs to improve reliability and resilience, by avoiding or shortening sustained outages, is heavily dependent on specific DER design and other technologies. DERs that are configured as part of a microgrid that segments a portion of a distribution system (“islanding”) may provide value that is considered beneficial to society and customers within the microgrid boundary. Several examples have been developed by utilities and communities.[124] [125] DER value related to islanded microgrid operation in such a configuration can be carefully considered alongside the feasibility, additional costs, and overall benefits of implementation in a given area.

However, behind-the-meter DERs that are configured as part of a customer’s microgrid, or that provide stand-alone backup power (e.g., onsite generator or battery) to their premises or campus, are typically not considered to provide benefits to other customers.

Operations and maintenance (O&M) spending reduction

Utility spending on operations and maintenance activities covers a relatively broad set of activities, some of which may be impacted by DERs. Considering reduction in O&M spending as a potential value driver requires identification of specific cost drivers and specific mechanisms that enable DERs to avoid those costs. DER operation also may increase O&M costs, such as load tap changer operations and

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[124] ComEd, Bronzeville Microgrid. https://www.energy.gov/eere/solar/project-profile-commonwealth-edison-company-shines

[125] Portland General Electric and City of Beaverton, Beaverton Microgrid. https://blog.energytrust.org/wp-content/uploads/2022/05/BeavertonPublicSafety_CS_05_2022_web.pdf

maintenance, due to increased operations from voltage fluctuations.[126] Any identified cost reduction will need to be netted against any increased costs.

Asset health

Asset health generally refers to the risk of failure of a given asset and the overall asset service lifespan. DERs can reduce the degree of loading on an asset, which may reduce risk of failure or extend asset lifespan, though there are limited data on the overall size of this effect. Conversely, DERs may negatively impact asset health, affecting DER value. For example, voltage regulators may experience increased tap operations due to DER adoption, though there are techniques and technologies (with associated costs) to reduce these effects. As a result, quantifying DER impacts on asset health is challenging.

Other DER impacts

If value streams beyond the distribution system are considered, they may be identified along with corresponding quantification methods and supporting information. Table 7-5 provides an example from Commonwealth Edison's Grid Plan in Illinois.

Table 7-5. Commonwealth Edison DER costs and benefits[127]

Impact Category	Timeline	Costs	Benefits
DER Owner	Short-Term	Interconnection costs, Equipment costs and financing, Electrical upgrade costs, Permits and Inspections	Reduced Energy Costs, Net Metering, Rebates/Tax Credits
	Long- Term	Changing Tariffs and Energy Costs	Wholesale Market Participation, Customer Back Up (resilience benefit)
Environmental	Short-Term	Upstream Manufacturing Emissions	Greenhouse Gas Emissions Reductions, Air Quality Improvement
	Long- Term	DER Recycling and Disposal	Reduction in Climate Change Impacts
Societal	Long- Term	Renewable Energy Credits	Environmental justice Health benefits associated with air quality improvements. Green/Sustainable living
Generation & Transmission	Short-Term Long-Term	Implementation and Management Costs for Wholesale Market Access, Transmission Modeling and NERC Compliance Costs	Wholesale Services (Energy, Capacity and Ancillary services)
Distribution Grid	Short-Term	Hosting Capacity Infrastructure Grid Investments, and DER Rebates	Distribution Capacity relief, Line loss reduction
	Long- Term	DER management and coordination	Outage support & resiliency, Voltage support

As illustrated in the example above, it is important to differentiate between positive DER contributions that impact the broad distribution system and positive DER contributions that benefit the DER owner or future DER interconnections, or which serve to offset otherwise detrimental system impacts of DER.

126 A tap operation occurs when a voltage regulator adjusts the line voltage, and the physical connection in the regulator is moved from one position to another. Fluctuations in DER output can impact system voltages and result in additional tap operations.

127 ComEd, ComEd Refiled Grid Plan - Chapter 5: Hosting Capacity and Interconnection Investments, p 42, 2024

Identifying the beneficiaries within each value stream is critical to ensuring the benefits are accounted for and allocated fairly across those impacted.

7.1.2 Distribution system input data

To understand the potential for DERs to provide value to the distribution system, it is critical to understand current system conditions, forecasted system growth and changes, and existing and future grid needs.

Grid needs assessment

The data within a grid needs assessment typically covers known and anticipated capacity, reliability, and other challenges for the distribution system. Fundamentally, the value of DERs is derived from their ability to address grid needs. Data related to grid needs are often presented across many different sections of utility distribution plans.

Long-term forecasts and expected system changes

Load and DER adoption forecasts are an important input to understanding future grid conditions. Typically, distribution plans contain forecasts for 5–10 years for assessing grid needs. When considering the DER value, it may be necessary to look further ahead to capture future needs that may be addressed by DERs. With DER lifespans in the range of 20 years or more, developing accurate forecasts for the entire period is difficult. Still, it is important to consider future expected conditions using the best information available.

Marginal cost of capacity

The marginal cost of utility distribution capacity can be used to evaluate and quantify future capacity contributions and their value. Marginal cost calculation methods may use short-term and long-term forecasts as an input. Regulators can consider providing guidance to utilities for including specific marginal cost study documents or results in filed distribution system plans.

Asset health information

Information about assets that make up the distribution system is important to understanding grid needs and optimizing investments across different options, including potential value provided by DERs. As an example, deferring a substation transformer replacement by using DERs to provide additional capacity may be highly cost-effective if the transformer is in good condition. On the other hand, if the transformer is already at a high risk of failure, it may be more cost-effective to replace the transformer instead. Asset health information is often included in distribution plan filings in some form.

Voltage support needs

Understanding existing voltage challenges and locations with voltage violations can be important for understanding DER value. Often, mitigation efforts for voltage violations involve lower-cost equipment, which may not be captured in distribution plan filings. Data related to customer voltage complaints may be more readily available, but is unlikely to capture all voltage needs.

Key Challenges with Value of DER in Distribution Planning

When reviewing data and methods in distribution system planning for determining DER value, some key challenges can make it difficult to assess the quality of information provided. Being aware of these challenges and engaging with utilities on these issues can help facilitate a constructive dialogue.

Scarce Content on Value of DER in Distribution System Plans

Valuation of DERs is not yet commonly practiced in the electric utility industry, and many utilities do not include value of DER considerations in distribution planning filings. Even in states such as New York, with a Value of Distributed Energy Resources rate offering to customers,[1] relevant inputs and assumptions for each utility's value of DER offering are provided separately from the distribution planning process. Guidance to utilities on proactive engagement and reporting with respect to value of DERs may be necessary to ensure relevant content is addressed in filed distribution system plans.

Methodology and Assumption Differences

Types of DER values considered, methodologies to calculate those values, and underlying assumptions—all of which can significantly impact valuation results—vary widely across jurisdictions. While there are leading practices and examples,[1] many aspects of determining the value of DER have yet to be conclusively settled. Marginal cost study methods, discussed above, are one such example, where methodological differences can have significant impacts on resulting DER value calculations.

Geospatial Granularity

A key decision for valuing DERs is the extent to which benefits are assessed (and in some cases compensated) based on their specific location. System-level methods, which do not vary benefit calculations or compensation by geographical location, are common. They result in consistent results but may overestimate or underestimate actual benefits for a given DER being interconnected at a particular location on the grid.

Incorporating more geographic granularity into the analysis—at the feeder/substation or point of interconnection level—can better match DER value to areas of need, increasing DER value for installations in locations where it provides greater benefits and decreasing DER value for installations in locations where it provides lower benefits. This approach can drive additional efficiency in resource deployment but comes with significantly more complexity. Consider the potential of DERs to reduce line losses. Figure 7-2 illustrates how variations in DER location can impact line losses. Geographic granularity can lead to two different customers installing the same type of DER system receiving differing levels of compensation, which can raise issues of fairness. Balancing these factors is an element of success within Value of DER.

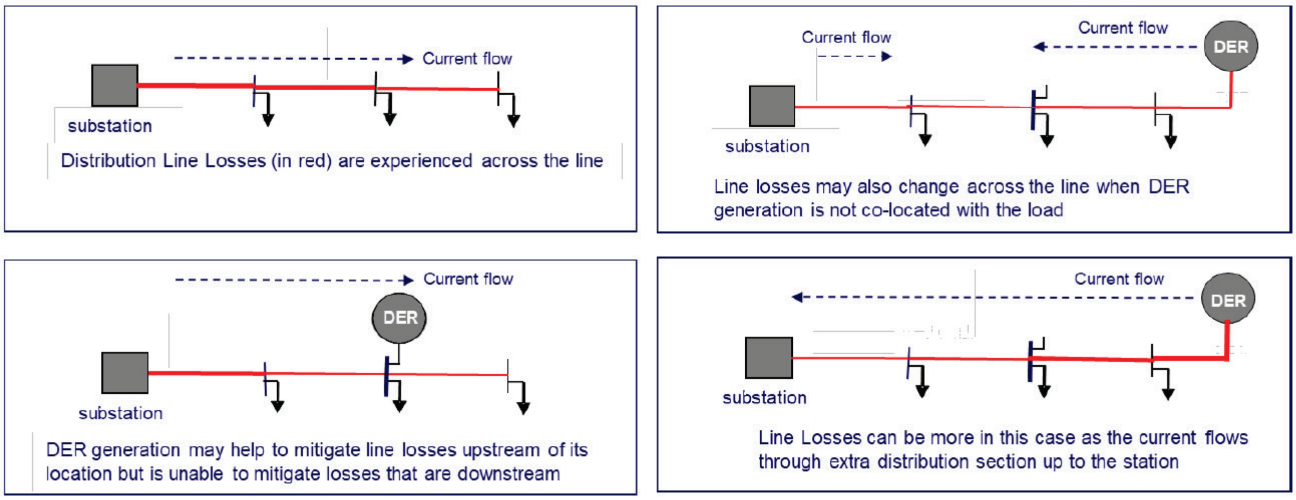


Figure 7-2. Line loss variation for varying DER locations – Commonwealth Edison[128]

Accounting for self-consumption

When assessing DER benefits, accurate accounting for customer self-consumption is critical to preventing double-counting. All else being equal, DER production that is self-consumed offsets local consumption that would otherwise be billed at full retail rates. To prevent double-counting, self-consumed energy can be removed from the resource profile or subtracted from the resulting value calculations. Self-consumption is highly efficient and generally desirable but must be accounted for when computing costs and benefits from a system perspective. Utilities can estimate self-consumption using customer PV system size and meter energy export data. In utility distribution planning filings, self-consumption should be addressed as part of the overall DER value determination process.

Customer understanding

To the extent that value of DER analysis is intended to inform DER compensation (either directly or via a third party), it is critical that customers understand how they will be compensated. Customers need to have sufficient information to ensure that they understand the project economics when determining whether to proceed with installing DER. Especially for DER value and compensation that varies by location and time, customers' ability to understand and respond to that information is part of developing programs and rates. While regulators typically approve programs and rates in separate tariff filings, distribution planning guidance for utilities can include providing information on design and implementation of value of DER programs and rates, including customer communications.

Investments with multiple benefit streams

DER value calculations have historically relied on avoided costs, especially for distribution capacity. While this is a useful approach for quantifying DER value, it is important to consider other values that may be provided by DER-based approaches, as well as traditional utility investments. When a distribution asset is replaced with a larger asset for capacity, the new asset is less prone to failure and

[128] ComEd, ComEd Refiled Grid Plan - Chapter 5: Hosting Capacity and Interconnection Investments, p 46, 2024

may have fewer maintenance and testing requirements as a result. Capturing the full extent of benefit streams is critical to a reasonable and holistic valuation framework, including calculation methods, in distribution system planning.

7.2 Data Outputs

While data inputs and methodologies for calculating DER value may be extensive, results are often simplistic, with a focus on dollar value equivalents for DERs providing specific grid services. Because DERs can impact all levels of the power system, transmission and bulk power system benefits may be analyzed alongside distribution value drivers to provide a more complete picture of DER value. The two most common formats for outputs from DER value processes are study reports and calculation tools.

Study reports generally document the input data, calculation methods, and resulting dollar equivalent values along with other jurisdiction-specific drivers. Table 7-6 illustrates resulting dollar values for different value streams included in these reports.

Table 7-6. DER avoided cost results for the District of Columbia (2020$/MWh)[129]

Impacts		Avg		
		2025	2035	2045
Energy		32	40	49
Generation Capacity		5	5	9
Transmission Capacity		3	3	3
Distribution Capacity, O&M, and Voltage	F1	1,258	279	238
	F2	136	245	254
	F3	109	224	193
	F4	0		
Distribution Losses		2	3	3
GHG	L	30	27	22
	M	70	59	47
	H	142	131	118
Public Health		8		
Other (Credit and Collections, Equity, Resilience)		34	34	35

Calculation tools provide a hands-on method for stakeholders to engage with and understand the value of DERs. Users can adjust inputs such as DER type, size, and location, and financial parameters to observe how inputs change the resulting dollar values. California's Avoided Cost Calculator[130] and New York's Solar Value Stack Calculator[131] (Figure 7-3) are examples of calculation tools. These tools are used to attribute long-run savings to DERs deployed across the system or in targeted locations, or both. For example, New York utilities use their annual marginal cost of service study to define two load reduction values for the Value Stack tariff:[132] one that is location-specific, and another that is systemwide. The Demand Reduction Value represents subtransmission and distribution costs that the utility avoids as a

129 Kallay, J. et al., *A Value of Distributed Energy Resources Study for the District of Columbia: Framework, Impacts, Key Findings, and Roadmap*, 2023

130 California Public Utilities Commission, DER Cost-Effectiveness. Avoided Cost Calculator (ACC), 2024

131 New York State, Solar Program (NY-SUN), The Value Stack, 2024

132 See https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources

result of DERs.[133] A higher Locational System Relief Value is available in utility-identified locations where DERs can address certain types of distribution investment needs. Compensation for this additional value targets highly constrained areas likely to require distribution system upgrades or other new investments in the absence of increased DER capacity contributions.

Value Stack Calculator v 3.1, for Projects Impacted by the 2019 Value Stack Order (Qualified after 7/26/2018)					
MONTHLY COMPENSATION FOR EXPORTS - SOLAR:					
	2024	*2024*	*2024*	*2024*	*2024*
	2024_1	*2024_2*	*2024_3*	*2024_4*	*2024_5*
	Jan-24	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**
Exports					
Solar generation immediately exported by solar system (kWh)	680,678	856,099	981,466	898,724	1,000,822
Value stack compensation from solar exports ($Nominal)					
Energy value	$ 63,444	$ 74,553	$ 52,898	$ 44,737	$ 57,819
Capacity value (36-month average Alternative 1 Rate (Jan 2021-Dec 2023) selected)	$ 13,325	$ 15,946	$ 7,421	$ 3,098	$ 13,784
Environmental value	$ 21,121	$ 26,565	$ 30,455	$ 27,887	$ 31,056
Demand reduction value	$ -	$ -	$ -	$ -	$ -
Locational system relief value	$ -	$ -	$ -	$ -	$ -
Community Credit	$ -	$ -	$ -	$ -	$ -
Total Value Stack compensation from solar generation immediately exported	$ 97,890	$ 117,064	$ 90,773	$ 75,722	$ 102,658
Average Value Stack compensation from solar - Per kWh exported ($Nominal/kWh)					
Energy value	$ 0.0932	$ 0.0871	$ 0.0539	$ 0.0498	$ 0.0578
Capacity value (36-month average Alternative 1 Rate (Jan 2021-Dec 2023) selected)	$ 0.0196	$ 0.0186	$ 0.0076	$ 0.0034	$ 0.0138
Environmental value	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310
Demand reduction value	$ -	$ -	$ -	$ -	$ -
Locational system relief value	$ -	$ -	$ -	$ -	$ -
Community Credit	$ -	$ -	$ -	$ -	$ -
Average Value Stack compensation, per kWh immediately exported	$ 0.1438	$ 0.1367	$ 0.0925	$ 0.0843	$ 0.1026
MONTHLY ON-SITE BILL REDUCTIONS FROM PROJECT:					
Retail rate taken from User Inputs row 123	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**
On-site consumption served by solar (kWh)	-	-	-	-	-
On-site parasitic load during hours with no solar generation (kWh)	-	-	-	-	-
Value of solar kWh consumed on site, at retail rate ($Nominal)	$ -	$ -	$ -	$ -	$ -

Figure 7-3. New York Solar Value Stack Calculator – Detailed outputs example

7.3 Best Practices

Best practices for sharing data on value of DERs include:

- Identify the types of DERs considered in value of DER analysis and explain the DER operational assumptions used.
- Identify specific distribution services considered in value of DER analysis and clearly document methodologies for quantifying the value of those services.
- To the extent practical, capture variations in DER value across the system due to differences in grid needs based on location.
- Accurately account for customer self-consumption to avoid double-counting benefits of behind-the-meter DER.

[133] In practice, some utilities quantify the costs of incremental transmission and distribution capacity instead of the demand reduction value.

8. Grid Needs Assessment

A *grid needs assessment* is an output of distribution system analysis that transparently identifies specific grid deficiencies over a set period (e.g., 10 years). Utilities leverage data from other distribution system analyses for the assessment, including load and DER forecasting and scenario analysis. The assessment includes a description of the deficiency, associated engineering characteristics, and timing of the need. Utilities prioritize grid needs identified and near-term actions.

The grid needs assessment informs the utility's distribution system investment strategy, including both traditional grid upgrades and pricing, programs, and procurements for non-wires alternatives (NWAs). The assessments also can support distribution system operations—for example, when the grid deficiency is projected to materialize before the utility can implement an infrastructure solution.

Utility data supporting the grid needs assessment allows regulators and stakeholders to understand the processes and analyses the utility used to identify investment needs, including robustness of approaches used. Utility data on identified grid needs, and their prioritization, is relevant to understanding capital project proposals presented for regulatory review. Utilities can report data and information related to the scope of the grid needs assessment, analytical approach, grid needs identification, and grid needs selection (Table 8-1).

Table 8-1. Grid needs assessment data categories and impacts on planning

Data category	Type of data reported	Impact of data on planning
Scope	Objectives and regulatory compliance	Establishes the breadth and depth of the assessment and how it fits into the utility's distribution system planning strategy
Analytical approach	Methodology, limitations, and tools	Characterizes the approach implemented to identify grid needs
Grid needs identification	Asset characteristics, description of grid need, cost estimates, timing of grid need, and engineering characteristics	Identifies assets impacted by grid deficiencies
Grid needs selection	Grid needs prioritization and solutions	Selects grid needs for near-term investments and describes the approach that will be used to identify solutions

8.1 Data Inputs

8.1.1 Scope of the assessment

The grid needs assessment is shaped by the utility's strategy and applicable state requirements. Information on the scope of the assessment enables regulators and stakeholders to understand the breadth and depth of the analysis and how it fits into the utility's distribution planning activities. Utilities can provide information on their objectives and regulatory compliance.

Objectives establish the intended outcome the utility aims to achieve through the analysis. In addition to meeting overarching objectives such as maintaining grid reliability and resilience, specific aims for the assessment may include ensuring that all grid needs are characterized in detail and considered for NWA procurements and geotargeted programs when suitable. This information helps regulators and stakeholders understand how the assessment fits within the utility's strategy.

Regulatory compliance describes how the utility followed state requirements and commission guidance for implementing the grid needs assessment. This information simplifies regulatory oversight, including reviewing the adequacy of the approach. Compliance information also can provide regulators with valuable information on assessment challenges and inform future regulatory actions to improve assessment practices. For example, Pacific Gas & Electric's *2024 Distribution Grid Needs Assessment* report provides information on applicable commission decisions and regulatory requirements.[134]

8.1.2 Analytical approach

Grid needs assessments require a robust analytical approach supported by accurate system and asset data and engineering analysis. Regulators and stakeholders benefit from data and information to understand the approach followed, assess its suitability, and provide recommendations for improvement when appropriate. Utilities can provide data on their methodology, limitations, and tools. Utility data on the *methodology* can include information on the process designed to identify grid needs. For example, in its 2023 Integrated Grid Plan, Hawaiian Electric provides its grid needs modeling framework and describes the steps included in the process (Figure 8-1). The framework also provides the logic criteria applied across the analysis to establish the final portfolio of grid needs. Utilities also can report on assumptions used to support the analysis, as well as the time frame.

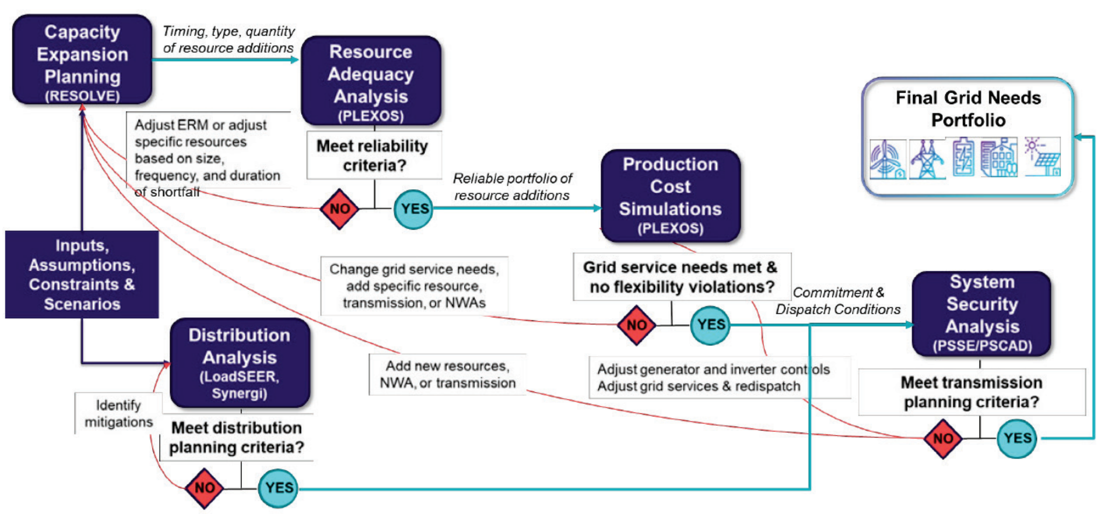


Figure 8-1. Grid needs modeling framework – Hawaiian Electric 2023 Integrated Grid Plan[135]

[134] PG&E, *2024 Distribution Grid Needs Assessment*, 2024a
[135] Hawaiian Electric, 2023 Integrated Grid Plan, 2023

Utilities can report *limitations,* including a description of any shortcomings of the existing analytical approach or future considerations to improve existing processes. This may include gaps in asset engineering data, load and DER forecast uncertainty, and analytical tool limitations. The data inform regulators of challenges in identifying grid needs and can aid the interpretation of results by providing relevant context. For example, PacifiCorp's 2022 Distribution System Plan for Oregon provides a set of lessons learned through its grid needs assessment process. These include the need for granular data to understand the magnitude of grid needs, including the time of day, duration, and number of times a year the deficiency occurs, and the importance of allocating sufficient time for analysis.[136]

Utilities also can provide information on the *tools* deployed to support their analysis, such as commercial software or utility-developed tools. This information can improve transparency of the utility's analytical approach and enable regulators to assess tool capabilities and adequacy. For example, Pacific Gas & Electric (PG&E) describes the tools necessary to support its grid needs assessment and how the utility combines multiple tools to identify grid needs and automate its workflow. The utility uses LoadSEER,[137] a distribution system forecasting software for substations and feeders, to generate inputs for the analysis. In addition, the utility describes the various tools used to support planning automation, including CYME's Forecast Integration Tool,[138] which supports feeder analysis and can store data and support other departments engaged in distribution system planning.[139]

8.2 Data Outputs

8.2.1 Grid needs identification

Utilities can provide a range of data and information to describe identified grid needs, including asset characteristics and a description, cost estimates, timing, and engineering characteristics of the grid need.

Data on *asset characteristics* provides information to identify equipment impacted by a grid need. Utilities can report unique identifiers used to track the affected distribution system assets and their location.

Utilities can provide information *describing the grid deficiency* impacting the assets. This information enables regulators to understand drivers for near-term investments proposed and can inform future distribution system planning guidance to address emerging grid needs. For instance, a utility may find that most of its grid needs are related to limited distribution capacity, which could spur regulators to strengthen planning processes to deploy cost-effective DERs to defer, reduce, or mitigate grid upgrades.

136 PacifiCorp, Docket UM 2198, Distribution System Plan Part 2, 2022
137 LoadSEER is developed by Integral Analytics.
138 CYME is developed by Eaton.
139 PG&E, *2024 Distribution Grid Needs Assessment*, 2024a

In Nevada, NV Energy reports the results of its assessment categorizing grid needs due to thermal, reliability, or voltage constraints.[140]

Utility data on *cost estimates* gives regulators and stakeholders a reference point on what a traditional "wires" solution may cost to solve the grid need identified. This cost estimate can inform regulatory decisions regarding the utility's selection of cost-effective solutions to meet grid needs. For example, Hawaiian Electric organizes cost estimates for grid needs as those related to hosting capacity constraints (i.e., the ability of distribution system assets to accommodate DERs) and location-based constraints (i.e., the ability of distribution system assets to serve forecasted load growth). For each type of need, the utility provides data for a range of scenarios (Table 8-2).

Table 8-2. Grid needs cost estimates for O'ahu – Hawaiian Electric 2023 Integrated Grid Plan[141]

O'ahu hosting capacity grid needs, 2023-2030

Parameter (Nominal $)	Base DER Forecast	High DER Forecast	Low DER Forecast
Number of grid needs	6	16	5
Cost summary (wires solutions)	$792,000	$3,895,000	$648,000

O'ahu location-based grid needs, 2023-2030

Parameter (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	22	41	19	29
Cost summary (wires solutions)	$95,724,000	$152,426,000	$77,900,000	$165,934,000

Utilities can provide data on the *timing of the grid need* to inform regulators and stakeholders of when an asset will be impacted to inform planning and investment decisions. In addition to stating the year when the grid need is expected, the utility can indicate the season (or month) in which the grid need is expected to materialize, and the start and end times the deficiency occurs to inform the selection of suitable solutions.

Utilities can describe the *engineering characteristics of the grid need identified*, including the operational condition when the grid need occurs—during normal operating conditions or when the system faces contingencies. Utilities also can provide data on the expected duration of the grid need, including the number of hours per year, the number of days per year when the asset experiences loading greater than its limit, and the number of hours on the forecasted peak day. These data allow regulators and stakeholders to understand the severity of the grid needs identified and can provide relevant information to support justifications of utility investment proposals.

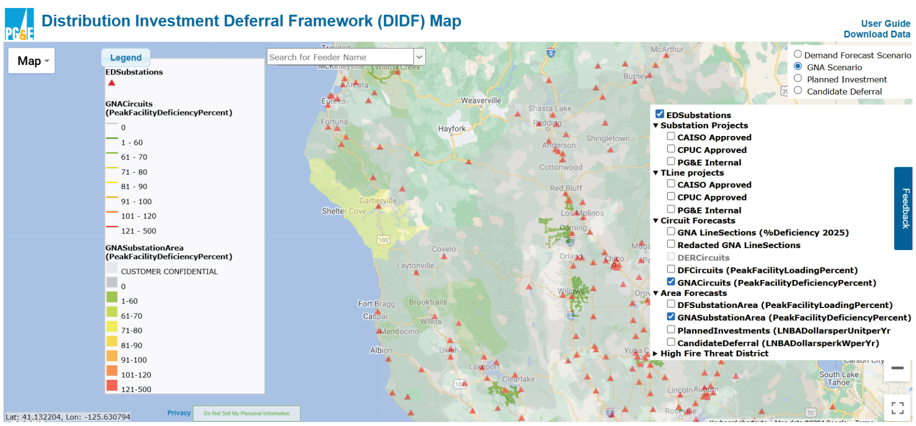
140 NV Energy, Docket 23-09002, 2023 Distributed Resources Plan, 2023.

141 Hawaiian Electric, *2023 Integrated Grid Plan*, 2023

Utilities typically provide data on grid needs identification through regulatory filings in report format. Utilities can complement these filings with web portals to increase access to data (see text box).

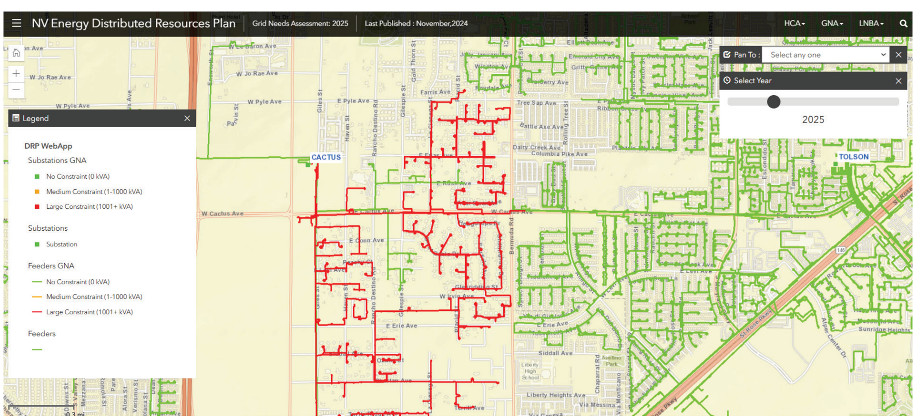
Online Portals for Data Access and Maps for Grid Needs

Utilities can use online portals to increase data access and transparency for grid need assessments. Online portals can provide mapping tools and enable downloading of granular data characterizing asset grid needs and provide mapping tools. Online portals are valuable for developers to identify areas where DERs may be a suitable solution to address grid needs. For example, PG&E's web portal provides data downloads and maps. The map allows users to toggle through various options to visualize grid deficiencies for feeders and substation areas. Users can select assets on the map to access more data, including the cause of the grid need, the date when the grid solution is needed, and the value of the grid need in MW and as a percentage of the asset capacity.[142]



Source: PG&E, Grid Needs Assessment Map, 2024

Similarly, NV Energy in Nevada has a web portal with mapping and data download capabilities.[143]



Source: NV Energy, Distributed Resources Plan Portal, 2024

142 PG&E, Distribution Investment Deferral Framework (DIDF) Map User Guide, 2022

143 NV Energy, Docket 24-05041, Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 Integrated Resource Plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027, 2024

8.2.2 Grid needs selection

The utility concludes its assessment by prioritizing grid needs for near-term investments. The distribution system plan can report on the utility's prioritization criteria and approach.

Utility information on *grid needs prioritization* provides details on how the utility selects the grid needs that require near-term action. This can include information on the methodology applied to rank grid needs. The information provides insights into factors driving utility investment priorities. Portland General Electric's 2022 Distribution System Plan included data on the utility's ranking methodology across five levels, with level 5 as the highest priority:[144]

- Level 5 – safety and customer commitment
- Level 4 – impacts to other facilities
- Level 3 – heavy loading telemetry, and substation risk
- Level 2 – feeder risk, load growth, and redundancy
- Level 1 – system utilization and DG readiness

The utility developed prioritization criteria and scores for each level to rank grid needs (Table 8-3).

Table 8-3. Grid needs prioritization criteria – Portland General Electric 2022 Distribution System Plan[145]

Level	Title	Max possible score	Multiplier	Max total	Peak importance
Level 5	Addresses Safety Concern? Yes = 15, No = 0	15	5	75	21.8%
	Must Do for Customer Commitment? Yes = 15, No = 0	15	5	75	21.8%
Level 4	Compliance Driver or Mitigates Transmission/ Sub-Transmission Constraint? 115 kV+ = 10, 57 kV = 5, No = 0	10	4	40	11.6%
	Precursor to mitigating other grid needs? Two or More = 10, One = 5, No = 0	10	4	40	11.6%
	Frees up or mitigates mobile/ temporary equipment or configuration? Yes = 5, No = 0	5	4	20	5.8%
Level 3	Feeder % Loading of Seasonal Limit (N-0) >100% = 4, 90%-99% = 3, 80%-89% = 2, 67%-79% = 1, <67% = 0	4	3	12	3.5%
	Transformer % Loading of LBNR (N-0) >100% = 4, 90%-99% = 3, 80%-89% = 2, <80% = 0	4	3	12	3.5%
	Existing Total Risk (Substation) Top 10 = 4, Top 30 = 2, Top 50 = 1, Other = 0	4	3	12	3.5%
	Existing CMI Impact (Substation) Top 10 = 4, Top 30 = 2, Top 50 = 1, Other = 0	4	3	12	3.5%
	Substation SCADA Adds New = 3, Replace Obsolete = 1, No or New Sub = 0	3	3	9	2.6%

LBNR – Loading Beyond Nameplate Ratings; CMI – Customer Minutes Interrupted; SCADA – Supervisory Control and Data Acquisition

144 PGE, Docket UM 2197, Distribution System Plan Part 2, 2022a

145 This figure includes only levels 3 to 5 for illustration. The full set of criteria can be found in Portland General Electric, Docket UM 2197, Distribution System Plan Part 2, 2022a, p 190.

Information on the utility's *approach to identifying grid needs solutions* describes processes suitable to address selected grid needs. Some grid needs may be suitable candidates for NWA procurements or geotargeted programs; others may require a grid upgrade. Utilities also can report the timeline for initiating the solution implementation process and the date by which a solution must be in place.

8.3 Best Practices

Best practices for sharing data on grid needs assessment include:

- Provide data on analytical steps followed to identify grid needs. This can include information on utility processes, including dependencies with other distribution planning activities such as load and DER forecasts and scenario analysis.
- Disclose commercial and utility-developed tools used and their role in the analysis. This can include a description of each tool, its capabilities, and how they fit into the utility grid needs assessment workflow. Utilities also can report any limitations and challenges experienced with available tools to inform future distribution planning efforts and enable regulators to understand existing hurdles, which may inform future planning guidance. Utilities may be able to use open-source tools, make their own tools available to stakeholders, or facilitate licenses for stakeholders for proprietary tools used.
- Share comprehensive grid deficiency data to enable identification of cost-effective solutions. This can include granular data to characterize the distribution system asset, the magnitude of the deficiency, and its expected duration.
- Leverage data portals to facilitate access by regulators, developers, and other stakeholders. This can include launching a web portal with data download capabilities and interactive maps to complement traditional regulatory filings.

9. Cost-Effectiveness Evaluation for Investments[146]

Cost-effectiveness evaluation assesses the benefits and costs of grid investments and qualitative factors to achieve established planning objectives to determine an optimal course of action. Utility data and analysis on cost-effectiveness are relevant for regulators and stakeholders to understand the economic impact of distribution system investments. Utility data on cost-effectiveness can support regulators in assessing and determining which investments may be appropriate for approval and deployment—and which investments may need to be assessed further prior to making a decision, postponed and considered in future proceedings, or rejected.

Table 9-1 summarizes categories and types of data that utilities can report related to cost-effectiveness evaluation and how the data impact distribution system planning.

Table 9-1. Cost-effectiveness data and impacts on planning

Data category	Type of data reported	Impact of data on planning
Solution justification data	Description of selected investments and other expenditures, expected outcomes, investment drivers (compliance with standards, regulations, or policies or enabling other new capabilities), and engineering analyses	Identifies alternatives considered, selected solutions, and rationale
Cost-effectiveness analysis screening	Scope of analysis (individual solution or integrated set of technologies), screening method, estimates of benefits and costs, uncertainty analyses, and ex-post results from prior distribution plans	Determines approach (lowest reasonable cost or benefit-cost analysis) the utility uses for initial economic evaluation of proposed expenditures based on investment drivers
Portfolio development	Scoring and ranking methods (e.g., multi-objective decision analysis, value-spend efficiency) and results, planned portfolio of expenditures	Prioritizes screened expenditures based on cost and potential contribution toward achieving planning objectives to create value for utility customers and society

A well-designed integrated distribution system planning (IDSP) process provides a framework for translating multiple policy objectives into holistic infrastructure investment strategies and related cost-effectiveness evaluation. That includes establishing metrics for each objective and prioritizing among them. The set of objectives, metrics, and priorities facilitates effective assessment of grid technology options, physical infrastructure alternatives, and operational expenditures (Figure 9-1). Importantly, customer affordability is the global objective that sets the financial constraint for cost-effectively optimizing a portfolio of distribution expenditures to achieve other planning objectives. A best practice is identifying each expenditure and linking it to one or more distribution modernization objectives and metrics. Many distribution modernization expenditures address more than one objective.

[146] Paul De Martini, Newport Consulting, is a significant contributor to this section of the report.

	Customer Affordability					
	Reduce Wildfire Risk	**Increase Grid Capacity**	**Improve Asset Health**	**Improve Reliability**	**Promote Equity**	**Increase Resilience**
Description	Reducing wildfire risk and preventative outage impacts to customers and communities	Expand grid capacity to remedy overloading and facilitate electrification	Address underlying asset health (e.g., age) issues that lead to failure	Reducing frequency and duration of outages	Ensure benefits of the grid are fairly distributed across all communities	Aim to build a more resilient to anticipated impacts of climate change and other natural disasters
Metrics	Wildfire Multi-factor Risk Score PSPS related CMI	Number and MW of substations & feeders overloaded	Risk-weighted share of unhealthy assets Percentage of assets past expected life and at risk of failure	SAIDI & SAIFI w/o Major Events CEMI	Percentage of expenditure in disadvantaged and vulnerable communities	Percentage of spend in areas at risk of climate and other natural hazards (e.g., earthquakes) Number of identified grid vulnerabilities addressed

Source: P. De Martini

Figure 9-1. Example utility grid planning objectives and metrics

Cost-Effectiveness Methods

There are two fundamental approaches for evaluating distribution investments:[147]

1. **Lowest reasonable cost:**[148] LRC (or "best fit, least cost") is a quantitatively focused method based on engineering or technology architectural analysis, or both, to discern the need for and cost of a solution based on compliance with statutory requirements and explicit and implicit regulatory requirements identified in the distribution planning process. LRC answers the question: *What is the lowest reasonable cost to meet a safety, reliability, or other statutory or regulatory requirement?* The approach requires clear alignment and supporting engineering rationale for meeting statutory and regulatory requirements. LRC also is applied to individual expenditures with interdependent relationships in which the full value is only realized when the interdependent components are all deployed.

2. **Benefit-cost analysis:** BCA is a quantitatively focused method based on monetizing the benefits and costs of distribution modernization expenditures over a defined time period. It is best used when the dollar value of the benefits of a distribution modernization solution is discrete and assignable, quantitatively measurable, and does not materially change with increasing or decreasing usage.[149] BCA answers the question: *Will a specific or interrelated group of grid expenditures enhance welfare (i.e., benefits > costs) for all or a subset of customers?*

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[147] De Martini, Ball, and Schwartz, *Economic Evaluation of Distribution Grid Modernization Expenditures: A Guide for Utility Regulators,* forthcoming.

[148] Utilities use a Lowest Reasonable Cost approach to justify reasonableness for many types of distribution expenditures, both capital investments and operating expenses, in general rate cases. De Martini et al. (2024) describes a more systematic approach to ensure transparency and alignment with planning objectives and priorities than methods often used for distribution-related expenditures in rate cases.

[149] DOE, Modern Distribution Grid: Strategy & Implementation Planning Guidebook. Vol. IV, 2020

The specific cost-effectiveness evaluation method to apply depends on state requirements and grid capabilities needed to meet state goals and objectives. Regardless of the method employed, utilities can share the underlying data related to grid needs, alignment with planning objectives, alternatives considered, and cost and benefit estimates. Given uncertainty, the level of detail and precision will be different for identified future expenditures compared to near-term expenditures. The utility can articulate the differences between longer-term and near-term cost-effectiveness calculations, including discussing the estimation methods employed.

9.1 Data Inputs

9.1.1 Grid need and solution justification data

After identifying needed investments, the utility can provide data to characterize them, and alternatives considered, laying out considerations for cost-effectiveness evaluation. Utility data for investment *characterization* includes a description of the selected capital investments and operating expenses included in the assessment and expected outcomes. Utilities also can provide information on the specific drivers and engineering analyses for the selected expenditures. Information characterizing selected expenditures enables regulators to assess how distribution system planning objectives translate into discrete grid needs and specific solutions. This "line of sight" between planning objectives and specific proposed expenditures is essential to a transparent IDSP process.

Information related to the utility's *cost-effectiveness considerations* includes the evaluation methodology applicable to the investment selected and a description of why the selected methodology is suitable for the investment under consideration. Information on the selected methodology helps regulators and stakeholders understand the utility's rationale and assess whether it matches regulatory priorities for cost-effective distribution system investments. Understanding which driver(s) informed a utility's choice of expenditures is critical to determining which cost-effectiveness methodology is appropriate for evaluating an expenditure (Figure 9-2).

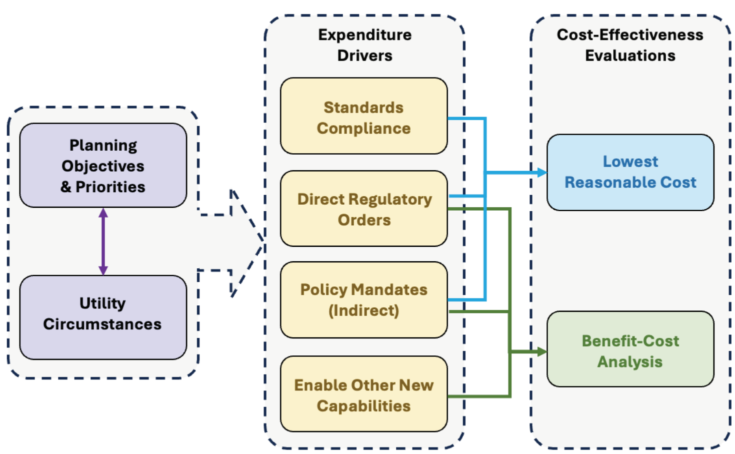

Figure 9-2. Drivers and cost-effectiveness evaluation methods[150]

[150] De Martini, P., J. Ball, and L. Schwartz. 2025

Figure 9-2 illustrates the following choices to assess the cost-effectiveness of various grid solutions based on the investment driver:

- **Standards compliance:** Solutions to comply with safety, power quality, and reliability standards are addressed using LRC.
- **Direct regulatory order:** Solutions in response to a regulatory order may be addressed using LRC or require a BCA, depending on whether the decision and order included a finding that the required capability was in the interest of the public and utility customers. If so, then the LRC method may apply.
- **Policy mandates:** For instance, legislation requiring commercial fleet and light-duty vehicle sales (by a certain date) considers societal value, and compliance with the statute may require new enabling grid capabilities. However, not all policy mandates identify the value to utility customers. In these cases, a BCA is used to determine the cost-effectiveness of solutions.
- **Other new capabilities:** Solutions identified by the utility to improve operations, but that are not driven by compliance, regulatory, or policy mandates, are evaluated using BCA.

States may have specific requirements indicating the methodology applicable for specific investment categories. Regardless of the cost-effectiveness analysis method, a clear narrative summary of a utility's decision is needed, based on planning objectives and priorities, grid needs, expenditure attributes, metrics, and relevant financial analysis.

9.2 Data Outputs

9.2.1 Benefit-cost analysis data

The utility can provide data and information on the scope of the analysis, cost-effectiveness methodology, cost and benefit estimation, uncertainty analyses, and any ex-post results from prior distribution system plans.

Utility data on the *scope of the analysis* can include a description of the specific grid solution or integrated set of IT/OT technologies analyzed.

Utility data and information on the *cost-effectiveness methodology* can include the description and rationale for its use in the analysis. For example, in its 2024 Multi-Year Integrated Grid Plan, Ameren Illinois provided regulators with information on its cost-effectiveness framework, outlining the utility's approach to evaluating different types of investments.[151] The framework describes the cost-effectiveness analytical approach for different types of investment drivers and provides examples of investments covered under different approaches.

Information on *estimation methods* to determine implementation and operational costs, and any

[151] Ameren Illinois, Ameren Illinois' Refiled Multi-Year Integrated Grid Plan, 2024

benefits associated with proposed expenditures, includes a discussion of method(s) used for conceptual estimates for future expenditures and benefits. Near-term expenditure costs can be supported by detailed information, including vendor price proposals. Likewise, near-term benefits may have greater detail based on recent information for benefit categories.

Conceptual cost estimates provide a basis to evaluate feasibility in long-term strategic planning included in distribution system plans. These estimates do not reflect a detailed design and business impact assessment or technology procurements. Conceptual cost estimates are developed through one or more of the following three cost engineering methods employed across industry sectors and government agencies:[152]

- **Historical estimating** uses historical data from similar projects as a basis for the cost estimate. The estimate can be adjusted for known differences between the projects. In the electric industry, this type of estimate is effective if there are significant historical cost data on electric infrastructure to draw upon. This estimating technique does not apply to new technologies that have no historical implementation information.
- **Parametric estimating** uses key parameters such as unit cost and quantity to calculate an estimate for deployment of devices or systems. For example, unit costs may be derived from historical average unit costs and industry cost guides (e.g., RSMeans Estimating Guidebook). AEP's Indiana-Michigan Power Company's 2019-2023 distribution plan[153] provides an example (Table 9-2). The total cost for each technology (e.g., "Station SCADA"), derived from an average unit cost, is multiplied by the quantity to develop a conceptual estimate.

[152] DOE, Modern Distribution Grid, Vol. IV, 2020
[153] Indiana Michigan Power Company, *Michigan Five-Year Distribution Plan (2019-2023),* 2019, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000004Q5rJAAS

Table 9-2. Parametric estimating example: Indiana Michigan Power Company's 2019-2023 Grid Modernization Investment Plan

Distribution Automation 2022				
Lakeside / New Buffalo	Union Pier / Bison	Install new automatic transfer scheme	1	Each
Main St / Riverside	Sears / Paw Paw Ave	Install new automatic transfer scheme	1	Each
		Total	2	
	Estimated O&M			
	Estimated Capital	$2,255,608		

Station SCADA 2020				
Station	Station	Description	Units	UOM
Stevensville	Stevensville	Install station SCADA	1	Each
Three Oaks	Three Oaks	Install station SCADA	1	Each
		Total	2	
	Estimated O&M			
	Estimated Capital	$2,393,443		

Station SCADA 2021				
Station	Station	Description	Units	UOM
Buchanan Hydro	Buchanan Hydro	Install station SCADA	1	Each
		Total	1	
	Estimated O&M			
	Estimated Capital	$1,175,727		

- **Equipment-factored estimating** typically takes the indicative/list price of the technology and multiplies it by installation and/or integration factors to determine conceptual costs. The installation factor, or total installed cost, includes technology vendor and consulting costs, associated internal project labor costs, additional costs needed for technology installation, and ongoing costs for operational and maintenance services.

Conceptual estimates developed using these top-down methods may include range estimates to frame the related *uncertainty*, as Table 9-3 shows.

Table 9-3. SCE grid modernization conceptual estimates

Category		Specific Investments	2015	2016	2017	2018 GRC (2018-2020)
Distribution Automation	#1	Automated Switches w/ Enhanced Telemetry	$500K - $1M	$3 - $5M	$35 - $60M	$185 - $320M
	#2	Remote Fault Indicators				
Substation Automation	#3	Substation Automation	$1.3 - $1.6M	$5 - $10M	$25 - $45M	$185 - $320M
	#4	Modern Protection Relays				
Communication Systems	#5	Field Area Network	$100 - $200K	$2 - $5M	$5 - $10M	$270 - $470M
	#6	Fiber Optic Network				
Technology Platforms and Applications	#7	Grid Analytics Platform	$10 - $13M	$65 - $100M	$55 - $85M	$215 - $375M
	#8	Grid Analytics Applications				
	#9	Long-Term Planning Tool Set				
	#10	Distribution Circuit Modeling Tool				
	#11	Generation Interconnection Application Processing Tool				
	#12	DRP Data Sharing Portal				
	#13	Grid and DER Management System				
	#14	Systems Architecture & Cybersecurity				
	#15	Distribution Volt/VAR Optimization				

Source: Southern California Edison

Conceptual estimates are not as detailed as values included in utility requests for cost recovery. However, these estimates can be useful to assess the magnitude of revenue requirements and associated rate impacts to consider customer affordability. Utilities in several states have incorporated conceptual estimates in distribution system plans to facilitate discussion about grid needs and affordability with regulators, utility customers, and other stakeholders.

Developing a detailed cost estimate ("engineering estimate") starts with detailed engineering design, related technologies, implementation plan, and vendor pricing. Engineering estimates involve estimating the cost for each major activity within the distribution system implementation plan. Engineering estimates for technologies and equipment usually are based on competitive vendor procurements or negotiated prices, or both. Remaining cost elements (such as various overhead charges) may be factored from direct labor and material costs.

Cost estimate summaries are typically provided in rate case filings, with detailed cost estimate analyses in work papers. Companion work papers may include information that is considered confidential vendor or service provider information. Access may be limited to regulatory staff and other parties in a regulatory proceeding under a nondisclosure agreement.

Utilities also can provide data related to *financial analysis*, such as cost escalation factors, discount rates, and the lifetime of the investments. It is important for regulators and stakeholders to understand the inputs and assumptions of the analysis. That may include describing how baseline data are generated for the analysis, as well as how *uncertainty* in selected inputs may affect cost-effectiveness analyses. Estimates often include contingencies based on these uncertainties to mitigate potential project risks. The utility can identify and discuss any contingencies incorporated into the analysis.

Sensitivity analysis can help utilities understand how variations in selected inputs may affect cost-effectiveness. Utilities can provide regulators and stakeholders with data and information on sensitivities included in the cost-effectiveness analysis.

Utilities use *ex-post cost and benefit data* to update cost and benefit assumptions and estimation factors as well as uncertainty analyses. Utilities can provide information on ex-post cost-effectiveness results from prior planning cycles and how they incorporated such data into current cost-effectiveness analyses.

9.2.2 Multi-objective prioritization

IDSP cost-effectiveness includes a determination of an optimal portfolio of expenditures in a specific time period[154] that provides tangible value to utility customers and society. Transparency in the methodology used is essential to the distribution system planning process. An effective multi-objective decision analysis (MODA)[155] supports a comprehensive, auditable, and robust assessment process that prioritizes expenditures aligned with established objectives and priorities. Utilities increasingly use MODA to prioritize distribution, given practical limits to utility spending due to customer affordability and utility financial and resource constraints, and regulators increasingly require utilities to conduct such analysis.

Since distribution planning typically addresses more than one objective, the utility identifies which solutions materially address the most objectives (or the highest priority objectives) for a given net cost. The MODA process assesses each proposed expenditure—whether first evaluated by Least Reasonable Cost or Benefit-Cost Analysis methods—quantitatively, qualitatively, or both against each objective and respective metric.[156] The utility defines each objective in quantitative terms (engineering or monetary metrics) or qualitative terms (e.g., safety attributes). The objective's priority ranking typically is reflected in a weighting factor applied to the total numerical score based on a proposed solution's contribution to addressing each objective (Figure 9-3). Using the resulting final score for each solution and its cost, the utility ranks each expenditure from highest to lowest score. Customer affordability is the global objective that sets the financial constraint for optimizing expenditures to achieve the other planning objectives.

Utilities can describe the prioritization methodology employed to determine the proposed portfolio of distribution expenditures, as well as the rationale for the scoring schema used to assess each expenditure's contribution toward achieving one or more objectives. For example, Portland General

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154 Cost recovery proceedings consider a single test year (or each rate year in the case of a multi-year rate plan). However, distribution planning usually identifies future needs and potential solutions across longer time frames (e.g., 10 years).

155 Several industries and governments use MODA — for example, state highway and transportation agencies. See [How to Implement a Multi-Objective Decision Analysis (MODA) Approach.]

156 For example, DTE has used a global prioritization model for several years. Other utilities have used weighted scores such as a Kepner-Tregoe framework. To aid in decision-making, utilities can convert non-monetary objectives to monetary values. See Baker et al. 2001 for an explanation of which types of projects each prioritization method is suited for and pros and cons.

Electric's (PGE) 2022 Distribution System Plan describes its MODA process (Figure 9-5). The scores are based on metrics developed using stakeholder input, statistical analysis, and heuristic adoption models. Each objective has an associated weight based on its priority, with the result that some objectives have a greater influence on the final project ranking.

Figure 9-3. Multi-objective prioritization for PGE's 2022 Distribution System Plan

9.3 Best Practices

Best practices for sharing data on cost-effectiveness evaluation include:

- Provide data to characterize distribution system expenditures evaluated for cost-effectiveness. That can include data on the specific distribution capital investments and operating expenses included in the assessment and information on how the expenditures address the identified grid needs.
- Ensure a transparent "line of sight" between each proposed distribution expenditure and its contribution to achieving one or more distribution planning objectives and requirements.
- Ensure that utility cost-effectiveness considerations align with distribution system planning objectives and criteria. The utility can provide detailed information on the cost-effectiveness methodology used and the rationale for selecting the approach. That can include assessment inputs, data sources, and information on any uncertainties affecting the analysis and mitigating actions.
- Provide a description and rationale of the cost and benefit estimation methodologies used for long-term and near-term cost-effectiveness determination.
- Provide information on the distribution expenditure prioritization method used, including details on how the utility incorporated planning objectives, the scoring approach and other factors employed, and the prioritization results.

10. Distribution System Investment Strategy and Implementation

The investment strategy is a utility's plan to achieve the objectives established for its distribution system planning process. The strategy addresses four interconnected dimensions:

1. **Asset management** includes traditional physical infrastructure, such as poles, wires, and transformers.
2. **Reliability and resilience** investments include physical upgrades, advanced technologies, and microgrids.
3. **Capacity expansion** includes physical upgrades and non-wires solutions, such as customer load flexibility and DER services.
4. **Advanced grid technology** includes solutions to advance monitor and control capabilities, including distribution automation. It also may include network and data management, planning and operational analytics, and technologies to enable DERs.

The investment strategy and implementation plan provides the utility's roadmap for meeting multiple DSP objectives in an affordable way over the planning horizon. The strategy and plan add transparency to the process by demonstrating how the utility translates planning objectives into expenditure decisions and provide context for the relationship between long-term goals and near-term needs. That supports regulatory review and stakeholder engagement with respect to how expenditures proposed for cost recovery in the short term, such as in a rate case, relate to future expenditure needs.

To prepare and implement the investment strategy, the utility relies on engineering, economic, and other technical data and analyses performed for the planning process. Sharing the information tells regulators and stakeholders how the utility identifies long-term investment needs and near-term investment proposals. Table 10-1 summarizes the investment strategy data and its impact on planning.

Table 10-1. Distribution system investment strategy and implementation data and impact on planning

Data category	Type of data reported	Impact on planning
Strategy development	Vision, objectives, strategy and investment drivers, capabilities and functionalities, grid architecture, and strategic roadmap	Characterizes the long-term evolution of the distribution system and enables regulators to assess alignment with state policy goals and objectives, as well as planning requirements
Strategy implementation	Progress to date, future implementation, investments planned, costs and financing, and risks and mitigation	Connects long-term strategic plans with near-term actions, allowing regulators to understand progress and assess the adequacy of proposed investments in relation to the utility's long-term strategy

10.1 Data Inputs

10.1.1 Strategy development

Utility data related to strategy development provides insights into the utility's long-term plan for the evolution of its distribution system. Information the utility can provide includes a vision statement, objectives, strategy and investment drivers, capabilities and functionalities, grid architecture, and a strategic roadmap.

The utility's *vision* establishes its long-term ambition for the distribution system over a defined time frame. For example, California,[157] Colorado,[158] and Minnesota[159] utilities provide data on their vision for the distribution system in the next 10 years. In its 2021 General Rate Case, Southern California Edison (SCE) provided information on its 10-year vision for grid modernization to support increasing system complexity, customer empowerment to contribute to grid operations, and distribution markets to maximize the value of DERs (Figure 10-1).[160] Regulators can use this information to assess the utility's proposed investments and determine if they adequately advance the utility's vision, as well as state policy goals and objectives.

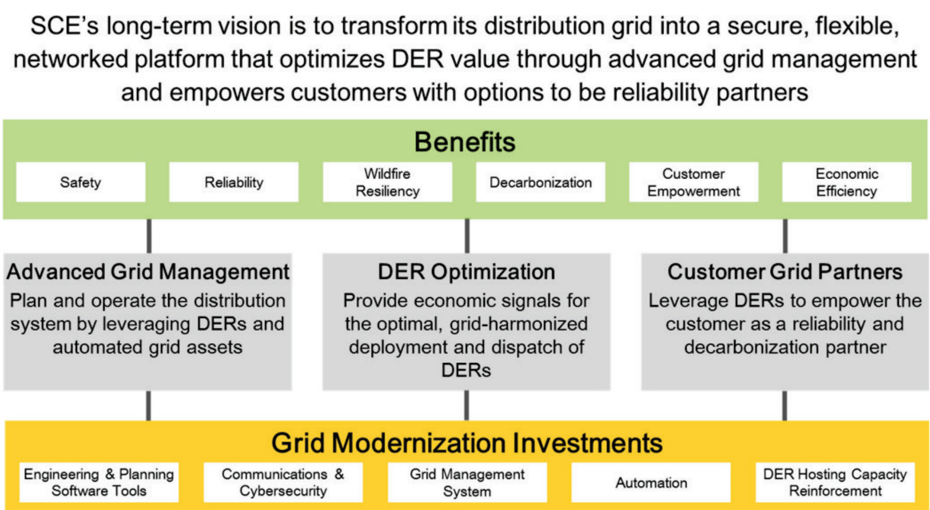

Figure 10-1. SCE's 10-year grid modernization vision[161]

The utility's *objectives* specify the outcomes the utility plans to achieve by implementing the distribution system strategy. For example, Xcel Energy in Colorado established the following objectives for its 2022 distribution system plan:[162]

- Implementing advanced forecasting and planning tools

[157] SCE, 2021 General Rate Case, Grid Modernization Plan, 2021
[158] Xcel Energy, Proceeding 22A-0189E, Distribution System Plan, 2022.
[159] Xcel Energy, Docket No. E002/M-23-452, Distribution System Plan, Appendix B1: Grid Modernization, 2023b
[160] SCE, 2021 General Rate Case, Grid Modernization Plan, 2021
[161] SCE, 2021 General Rate Case, Grid Modernization Plan, 2021 at 6
[162] Xcel Energy, Proceeding 22A-0189E, Distribution System Plan, 2022, p 11.

- Improving asset health and reliability
- Emphasizing resiliency
- Enhancing DER monitoring and control capabilities
- Evolving demand-side management and DER offerings to meet distribution system needs
- Harnessing stakeholder input
- Enabling interconnection of DER

Utilities can provide information to regulators and stakeholders on market, policy and regulatory, and technology drivers to support a better understanding of proposed investments:

- *Market-related drivers* may include technology adoption, customer behavior, and any expected implications for system operations that may need to be addressed through specific investments.
- *Policy and regulatory-related drivers* may include information on new state or federal laws or commission rules impacting the distribution system.
- *Technology drivers* may include information on advancements in modern grid technologies and expected impacts on grid operations and system functionalities. For example, Eversource's Electric-Sector Modernization Plan for its Massachusetts service area included data on EV contributions to system peak demand over time by sub-region (Figure 10-2).

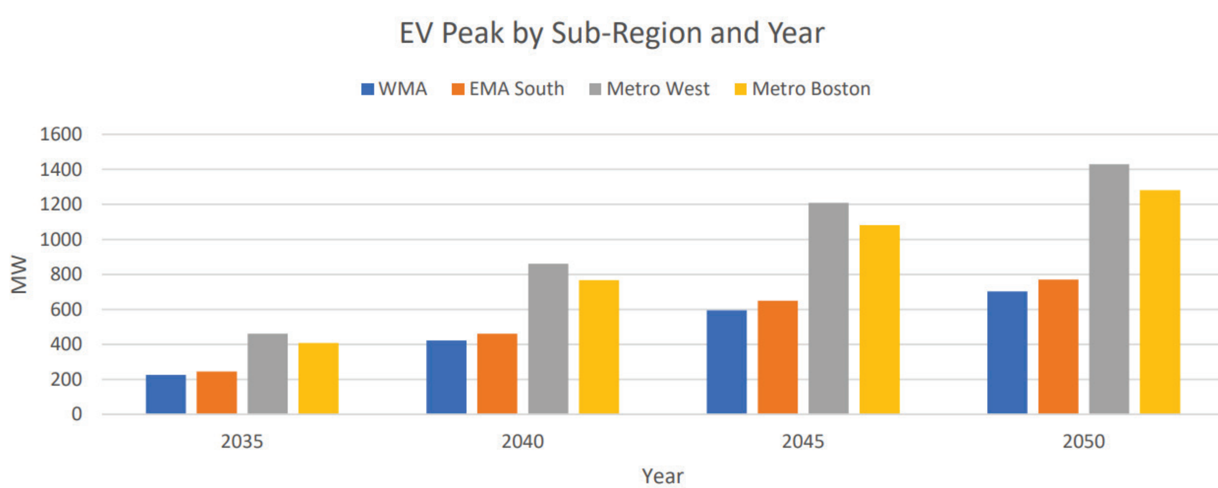

Figure 10-2. Eversource data on EV contribution to peak demand[163]

Notes: WMA: Western Massachusetts; EMA South: Eastern Massachusetts South

Utilities can provide data on the specific *capabilities and functionalities* enabled by the distribution system investments included in their strategy. A *capability* is the ability to execute a specific course of action, which may result from a combination of processes and technologies. An example of a distribution system capability can be to provide customers with access to their energy usage data. Capabilities inform what functions are needed. A *function* defines a business process, behavior, or operational result of a process. Planning identifies required changes to existing functions as well as new functions needed. Identifying functions within the context of needed capabilities to meet objectives is a

[163] Eversource Energy, *Electric Sector Modernization Plan*, 2024, p 509.

key reference point for strategic planning. Multiple functions can be combined to enable a capability. An example of distribution system functionality is deploying remote meter-reading, which would support access to energy usage data.[164] Rhode Island Energy included data on its capabilities and associated functionalities in its Grid Modernization Plan (Table 10-2).

Table 10-2. Rhode Island Energy grid modernization capabilities and functionalities[165]

Grid Modernization Capability	Grid Modernization Functionality
Customer Enablement	Advanced Metering (Customer Information, Advanced Pricing, Remote Metering) Distribution System Information Sharing
Monitoring & Control	Observability (Monitoring & Sensing) Distribution grid control (i.e., voltage control and fault management for compliance, flow control and state estimation) DER Management
Optimization	Voltage Control for Optimization Reliability Management DER Management
Data Acquisition	Operational Information Management Cyber Security Operational Telecommunications
System Modeling & Analytics	Distribution System Representation (Network Models) Grid Optimization

Utilities also can provide information on their *grid architecture* and how such considerations support the distribution system investment strategy, encompassing both the physical grid components and corresponding communication, control, and software systems. Grid architecture structures the planning and design of electric systems. It establishes the boundaries of what the grid can and cannot do and is an important component to support investment decisions.[166] Utilities can provide information on grid architecture by describing coordination, scalability, layering, and buffering considerations.

- *Coordination* is the process that causes or enables a set of decentralized elements to cooperate to solve a common problem.
- *Scalability* is the ability of a system to accommodate an expanding number of endpoints or participants without having to undertake major rework.
- *Layering* is applying fundamental or commonly needed capabilities and services to a variable set of uses or applications through well-defined interoperable interfaces (leading to the concept of a platform).
- *Buffering* is the ability to make the system resilient to a variety of disturbances.

Utility data on grid architecture may answer the following questions (Table 10-3).

[164] DOE, Modern Distribution Grid Strategy and Implementation Planning Guidebook Volume IV, 2020
[165] Rhode Island Energy, Grid Modernization Plan, 2022, p 73.
[166] DOE, *Modern Distribution Grid Strategy and Implementation Planning Guidebook Volume IV*, 2020

Table 10-3. Grid architecture questions that can be answered with utility data[167]

Coordination	How will we coordinate utility and non-utility assets? How will we address the information sharing requirements among participants?
Scalability	How do we enable optimal performance locally and systemwide? How do we minimize the number of communication interfaces (cyber-intrusion)?
Layering	How do we build out the fundamental components of the system to support new applications and convergence with other infrastructures?
Buffering	How do we address resilience and system flexibility requirements (e.g., what is the role of storage)?

In addition, utilities can provide information on their *strategic roadmap,* identifying current and future distribution system projects and initiatives and how they support the utility's strategy. The roadmap includes sequencing and relationships between projects and initiatives and indicates their status—completed, in progress, or planned for future implementation. For example, Figure 10-3 is the roadmap that Consolidated Edison filed with its 2023 Distribution System Implementation Plan.[168] The Gantt chart organizes projects and initiatives by theme, such as Advanced Metering and Grid Automation and Management, provides an overview of activities over time, and identifies milestones linking specific activities to regulatory proceedings, such as rate cases or distribution system implementation planning dockets.

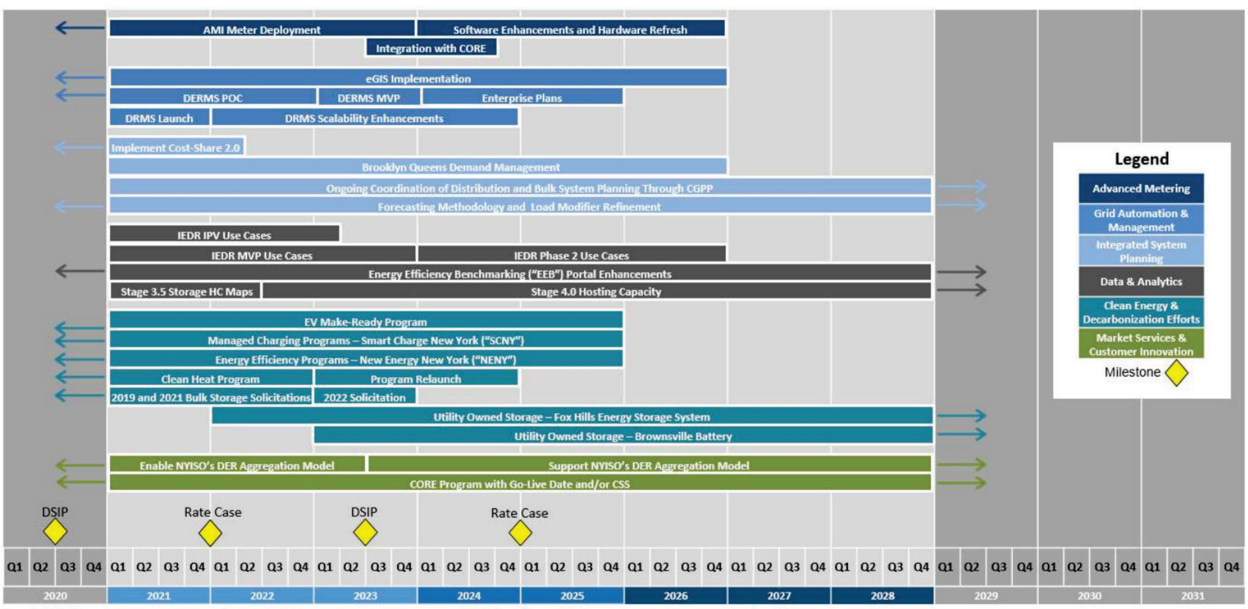

Figure 10-3. Consolidated Edison strategic roadmap[169]

[167] LBNL, Interactive Decision Framework for Integrated Distribution System Planning, Grid Architecture Considerations, 2024

[168] Consolidated Edison, Distribution System Implementation Plan, 2023, p 14.

[169] Consolidated Edison, Distribution System Implementation Plan, 2023, p 14.

10.2 Data Outputs

10.2.1 Strategy implementation

Utility data on strategy implementation provides regulators and stakeholders with information on past progress and future planned activities. Data translates ambitions (set during strategy development) into tangible investments the utility plans to pursue in the near term as necessary steps to deliver on its long-term vision and objectives. Strategic implementation data includes information on progress to date, future implementation, investments planned, costs and financing, and risks and mitigation.

Utility data on *progress to date* describes past strategy implementation efforts, such as priorities established in previous distribution system plans. A narrative may be included to describe how the utility's priority investments support achievement of the distribution system strategy. In Michigan, for example, DTE Electric Company's 2023 distribution grid plan provided a summary of progress on strategic investments included in its prior plan to provide insight into how the utility has performed in delivering strategic objectives (Table 10-4). The narrative also can explain any delays in delivering previously proposed investments, which can support an assessment of any challenges faced by the utility and lessons learned, and can inform future investment decisions.

Table 10-4. DTE's progress on 2021 distribution grid plan strategic investments[170]

Investment	Progress
Technology and Automation	• Opened the new Electric System Operations Center (eSOC) in 2022 • Launched the Outage Management System (OMS) and Distribution Management System (DMS) components of Advanced Distribution Management System (ADMS) in February 2023
Pole Top Maintenance and Modernization (PTMM)	• Replaced 5,553 poles (2021-2022) through the PTMM program and on track to replace 3,353 poles in 2023
4.8kV Hardening	• Hardened 677 miles of overhead circuits in the city of Detroit and on track to harden 345 additional miles by the end of 2023
Tree Trim	• 80% of the system is now on a five-year tree trimming cycle and the company goal is to be 100% on cycle by the end of 2025
Conversion	• Energized two new 13.2kV substations in the city of Detroit (Corktown Substation and Island View Substation)

Utility information on *future implementation* can include a forward-looking description of how strategy implementation efforts are organized and managed and how they support stakeholder needs. For example, Consolidated Edison provides a narrative of its future implementation efforts for each topical area covered by its Distribution System Implementation Plan.[171]

[170] DTE, *2023 Distribution Grid Plan*, 2023, p 13

[171] Consolidated Edison, *Distribution System Implementation Plan*, June 2023

Data on *investments planned* can include the specific technologies the utility will invest in, as well as any alternatives considered in the technology selection process. Utilities also can provide information on functionalities enabled by selected technologies. For example, Portland General Electric's 2022 Distribution System Plan provided information on alternatives for proposed investments, including deploying NWAs to address system capacity needs.[172] In the case of the Eastport substation, the utility identified the need for near-term investments to address a capacity constraint. In addition to considering a traditional solution, including transformer and feeder upgrades at an estimated cost of $2.8 million, the utility analyzed NWAs such as energy efficiency, demand response, solar, and storage. Table 10-5 first shows the reliability violation for the substation that requires near-term investments, then summarizes the grid need and traditional and alternative investments analyzed.

Table 10-5. Portland General Electric's analysis of investment alternatives for Eastport Substation[173]

Parameter	Value under normal condition (N-0 condition)
Violation type	Planning criteria violation (thermal) for both the Eastport-Plaza feeder and Eastport WR1 transformer
Applicable areas for load relief	Entire scope of Eastport-Plaza and Eastport-76th feeders
Violation time and duration	1-7 PM, Summer weekdays, non-holidays

NWS candidate: Eastport-Plaza and Eastport WR1	
Scope of grid need	Planning criteria violation on Eastport-Plaza and Eastport WR1
	Violation seen on summer weekdays from 1pm-7pm
	Relief can be provided anywhere along the feeder and partially at the substation
Traditional solution	Substation transformer upgrade and feeder section reconductoring
NWS	Energy efficiency • 5,500,000 kWh/yr annual savings by 2032
	Demand response • 2,166 kW of summer peak demand potential by 2032
	Solar and storage • 2,940 nameplate kW-dc of residential rooftop solar PV • 743 nameplate kW-dc of non-residential rooftop solar PV • 1,000 nameplate kW-dc of Community Solar installations
Decision making metrics	Relief can be provided anywhere along the feeder and partially at the substation
Community engagement	Performed outreach to CBOs through four Community Workshops (see **Section 2.4**)
	Conducted outreach to schools and government partners in the affected area to align plans with existing efforts and potential projects
	Going forward, will conduct detailed community needs assessment for the Eastport area by working directly with CBOs with connections and existing relationships in the area (see the community needs assessment section of **Appendix E**)

[172] PGE, *Distribution System Plan Part 2*, 2022a

[173] PGE, *Distribution System Plan Part 2*, 2022a

Data on *cost and financing* can include information on the utility's approach to prioritize investments, the level of proposed spending required to achieve strategic objectives, and any alternative financing mechanisms that may have been considered. For example, DTE includes its Global Prioritization Model in its distribution grid plan filing, providing information on the utility's approach to prioritizing investments (Table 10-6). "Impact Dimensions" are the benefits the utility assesses for each investment. "Drivers" specify how the utility measures each benefit. The "Weight" indicates how DTE prioritizes various benefits. In this example, investments that support reduced electrical hazards, load relief, and reduced duration and frequency of outage events are ranked higher and selected for earlier investment.

Table 10-6. DTE's Global Prioritization Model[174]

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	• Reduction in wire down events • Reduction in secondary network cable manhole events	3
Overload Relief	• Elimination of overloaded equipment	
SAIDI	• Reduction in duration of outage events	
SAIFI	• Reduction in frequency of outage events	
Regulatory Compliance	• MPSC staff's recommendation (March 30, 2010 report) on utilities' pole inspection program • Docket U-12270 – Service restoration under normal conditions within 8 hours • Docket U-12270 – Service restoration under catastrophic conditions within 60 hours • Docket U-12270 – Service restoration under all conditions within 36 hours • Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	2
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	• Elimination of system capacity constraints	
Investment in EJ Communities	• Percent of customers impacted by investment in EJ communities	
O&M Avoidance	• Trouble event reduction and truck roll reduction • Preventive maintenance investment reduction	1
Capital Avoidance	• Trouble event reduction and truck roll reduction • Reduction in capital replacement either during equipment failures or avoided planned capital work	

Utility data on *risks and mitigation* can include details on the methodology used to identify implementation risks, a description of the implementation risks identified, as well as the measures proposed to mitigate identified risks. For instance, Consolidated Edison provides a description of risks

174 DTE, *2023 Distribution Grid Plan*, 2023, p 167

and mitigation measures for each distribution system topic included in its 2023 Distribution System Implementation Plan.[175]

10.3 Best Practices

Best practices for sharing data on distribution system investment strategy and implementation include:

- Provide data and information to communicate the proposed distribution system evolution effectively. This can include the utility's articulation of its vision for the next 10 years and the associated objectives to deliver that vision.
- Include information on near-term capabilities and functionalities needed to modernize the distribution system. This can include a description of selected capabilities and supporting functionalities. Utilities also can indicate how these capabilities and functionalities support its vision of the distribution system vision and align with state policy goals, planning objectives, and priorities.
- Provide information on completed, ongoing, and future projects and initiatives necessary to achieve the long-term vision. This can include a strategic roadmap identifying projects and initiatives and their sequencing and relationships.
- Report on progress and future investment needs. This can include data on progress achieved on priorities established in previous distribution system plans and identification of future investment needs to achieve near-term and long-term goals.

[175] Consolidated Edison, *Distribution System Implementation Plan*, June 2023b

11. Geotargeted Programs

Geotargeted programs provide utility customer incentives for DERs to reduce load growth for specific locations on the distribution system and reduce the need for system upgrades. Utilities and third-party administrators provide an upfront rebate or other incentive for customers to install a specific technology (e.g., an energy-efficient appliance or smart thermostat), or offer opportunities for customers to earn revenues by operating qualifying technologies in ways that reduce peak demand on distribution circuits and substations—or provide both upfront and ongoing incentives. Geotargeted programs are another way to source non-wires alternatives (Chapter 12).

Geotargeted programs can leverage existing DER programs and customer relationships to address specific grid needs. That may reduce the timeline between identifying grid needs and deploying solutions. New geotargeted programs can leverage previous experience in program design, participant recruitment and retention, and impacts to facilitate program effectiveness.[176]

Utility data and analysis related to geotargeted programs can provide utility regulators and stakeholders with valuable information to understand and assess proposals for adapted or new DER programs, identify program needs, establish program design characteristics, evaluate program effectiveness, and make any adjustments necessary for continued program success. Table 11-1 is a summary of geotargeted program data and their impact on planning.

Table 11-1. Geotargeted program data categories and impacts on planning

Data category	Type of data reported	Impact of data on planning
Program needs	Program goals, locational characteristics, and operational and technical requirements	Defines suitability and technical characteristics of geotargeted programs to meet grid needs
Program design and deployment	Eligible measures, program duration, customer participation, and marketing, education, and outreach	Identifies program elements and deployment activities
Evaluation of program performance	Technologies and measures deployed, program effectiveness, community engagement, program budget, and cost-effectiveness	Supports decision-making on continuing and refining program design and deployment

11.1 Data Inputs

11.1.1 Geotargeted program needs

Utilities leverage data from distribution planning analyses, including grid needs assessments (Chapter 8), to identify suitable locations and other technical characteristics for geotargeted programs. Utilities can characterize geotargeted program needs by providing data on program goals, locational characteristics, and operational technical requirements.

[176] For more information on geotargeted programs, see Berkeley Lab's Interactive Decision Framework for Integrated Distribution System Planning.

Program goals: Information on outcomes typically includes the expected load reduction goal (e.g., kilowatt reduction) and total investment deferral. Data on program goals enables regulators and stakeholders to understand the anticipated magnitude of anticipated program achievements. Utilities in Michigan, Minnesota, New York, and Rhode Island have provided data on geotargeted program goals (Table 11-2).

Table 11-2. Examples of geotargeted program goals

State	Utility	Program	Geotargeted program goals		
			Type of investment deferral	**Investment deferral ($)**	**Peak load reduction**
MI	Consumers Energy	Swartz Creek[177]	Defer capacity upgrade, substation	$1.1 million	1.4 MW
MN	Xcel Energy	Geotargeted Distributed Clean Energy Initiative[178]	Defer capacity upgrade, transformer, and circuit	$4.1 million	500 kW
NY	Consolidated Edison	Brooklyn/Queens Demand Management Program[179]	Defer capacity upgrade, substation, and circuit	$1 billion	69 MW
RI	National Gird	Tiverton Pilot[180]	Defer capacity upgrade, 6 circuits	$2.9 million	1 MW

Locational characteristics: The grid needs assessment identifies distribution system assets suitable for geotargeted programs and locational characteristics. Data vary based on the grid need (e.g., circuit, transformer, substation) in the targeted location. Utilities can report locational characteristics using maps to provide a visual representation of targeted assets and locations. Data on locational characteristics may include customer information, such as customer accounts per class in the location targeted by the program. For example, for its Tiverton Pilot, National Grid in Rhode Island provided data on customer accounts per class served in the targeted area, total load (kilowatt-hour [kWh]) per class per year, and average load per account per year (Table 11-3). Such data help regulators and stakeholders understand potential program savings and inform decisions on the types of technologies and approaches (incentives, communications and customer engagement campaigns) that may be used to achieve program goals, such as peak load reduction.

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177 SEPA, *Non-Wires Alternatives: Case Studies from Leading U.S. Projects*, 2018

178 CEE, *Non-wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot Geotargeted Distributed Clean Energy Initiative Update Report*, 2021

179 NY DPS, Docket 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, August 2014

180 SEPA, *Non-Wires Alternatives: Case Studies from Leading U.S. Projects*, 2018

Table 11-3. Customers served by the Tiverton substation – National Grid, Rhode Island[181]

	Accounts	Load (kWh)	Average kWh Per Account Per Year
Residential	5,144	43,999,415	8,554
Commercial	470	10,292,822	21,900
Total	5,614	54,292,237	

Operational and technical requirements: Granular information on grid characteristics inform the timing of the grid need that the program will address, such as the months the grid need is observed. Other data may include the maximum number and duration of events the program will call. For instance, PG&E provided detailed information[182] on deferral needs that could be addressed by geotargeted programs and NWA solicitations for the 2023-2024 period, including targeted procurement (MW) per location, delivery month range, number of event calls per year, and day and hour range when those events would occur (Table 11-4).

Table 11-4. Data on distribution grid deferral needs – PG&E[183]

Deferral Need	Grid Need Location	Targeted Procurement (MW)	Delivery Month Range	Max Calls/ Year	Delivery Hour Range	Hours Duration	Delivery Day Range	In-Service Date
Camden 1106	Hardwick Bank 1	1.72	Jun-Aug	84	4PM-11PM	5	Mon-Sun	2026
	Henrietta Bank 5	1.73	Apr-Jul	39	12AM-4AM 4PM-9PM	4	Mon-Sun	2026
	Camden 1102	1.90	Jun-Aug	84	12PM-10PM	7	Mon-Sun	2026
Giffen Bank 2	Giffen Bank 1	10.57	Apr-Oct	197	12AM-12AM	24	Mon-Sun	2026
	Giffen 1103	0.20	Jun-Jul	30	12AM-2AM 6AM-11PM	5	Mon-Sun	2026
	Giffen 1102	CC	CC	CC	CC	CC	CC	2026
Green Valley Bank 4	Green Valley Bank 3	0.26	May-Oct	65	8AM-11AM 4PM-8PM	3	Mon-Fri	2026
	Green Valley Bank 2	2.19	Apr-Oct	153	7AM-12PM 4PM-8PM	7	Mon-Sun	2026

PG&E redacted data for the Giffen 1102 location (marked as CC, Customer Confidential), demonstrating

181 National Grid, 2012 System Reliability Procurement Plan, November 2011

182 PG&E provided these data as part of its geotargeted programs conducted under its Distribution Investment Deferral Framework (DIDF) Partnership Pilot. Through these programs, the utility procuress Distributed Energy Resources (DERs) from third-party aggregators to avoid or defer distribution system investments. The CPUC approved these pilots in its Decision 21-02-006 of February 11, 2021.

183 PG&E, PG&E's Participants' Webinar, Distribution Investment Deferral Framework (DIDF) 2023-24 Partnership Pilot RFO, January 2024b

how customer privacy can be maintained in cases where providing granular data would reveal customer-specific data. The California Public Utilities Commission requires data to be redacted if it meets any of the following criteria, referred to as the 15/15 rule:[184]

- One single customer represents up to 15% of the total consumption
- There are less than 15 customers served by the asset[185]

PG&E also provides data on load profiles for assets targeted by the program. For instance, for the Green Valley Bank 4 deferral need, the utility provides load profiles for each month included in the delivery month range for the grid need, the summer rating for the facility targeted, and the load reduction needed to address the grid need (Figure 11-1).

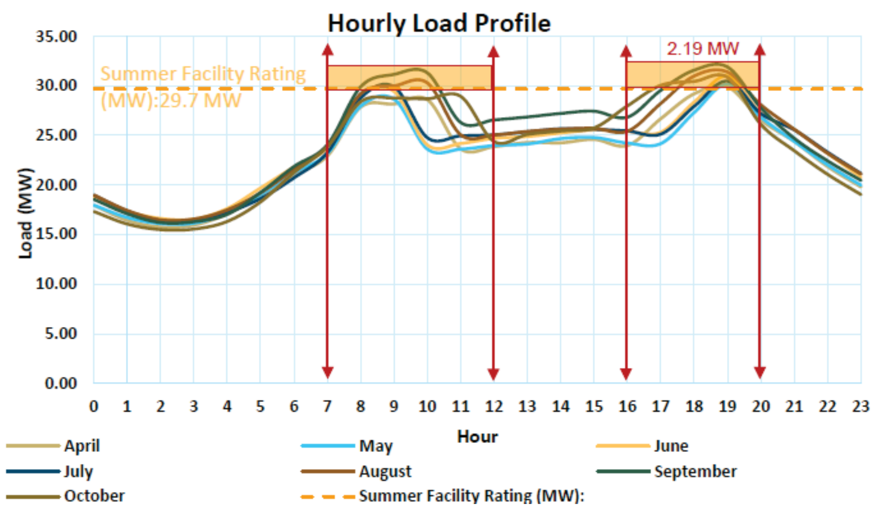

Figure 11-1. Hourly load profiles for Green Valley Bank 4 substation – PG&E[186]

11.2 Data Outputs

11.2.1 Geotargeted program design and deployment

Utility data on geotargeted program design informs approaches that can be pursued to address the grid needs selected. Data can include information on program deployment, measures eligible, program duration, customer participation, incentive types, and information on marketing, education, and outreach. Data on geotargeted program design allows regulators and stakeholders to assess program deployment plans and identify program design elements that may require additional detail and development.

[184] CPUC, Decision 14-05-016, Decision Adopting Rules to Provide Access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data, May 2014b
[185] If third-party providers want to access customer confidential information to offer or participate in geotargeted programs, parties must sign a Non-Disclosure and Use of Information Agreement.
[186] PG&E, PG&E's Participants' Webinar, Distribution Investment Deferral Framework (DIDF) 2023-24 Partnership Pilot RFO, January 2024b

Information on *program deployment* specifies whether program delivery will be governed by the utility or a third party.

Information on *eligible measures* may include data on qualifying technologies for each customer class and participation targets. For instance, Table 11-5 provides a breakdown of measures that Xcel Energy in Minnesota included in its Geotargeted Distributed Clean Energy Initiative for residential and commercial customers.[187] The utility also describes the incremental customer participation needed (NWA incremental participation goal) to ensure the program achieves set goals.

Table 11-5. Data for energy efficiency measures – Xcel Energy's Geotargeted Distributed Clean Energy Initiative[188]

	Average annual participants (2015–2017)	NWA incremental participation goal	Total assumed 2019 participants	NWA incremental demand reduction (kW)
Residential lighting direct installation	20	130	150	23 kW
Residential light bulb giveaways	—	1,200 (bulbs)	1,200 (bulbs)	6 kW
Residential smart thermostat direct installation and demand response enrollment	18	80	98	72 kW
Commercial refrigeration efficiency	—	7	7	86kW
Commercial lighting efficiency	38	40	78	302kW
Commercial cooling efficiency	7	7	14	14 kW
Total demand reduction				**502 kW**

In addition, Xcel Energy benchmarked expected hourly measure performance against its program goal of delivering 500 kW of load reduction (Figure 11-2). The analysis shows how the utility expects new incentives for energy-efficient residential air-conditioning to reduce peak load (between hours 17:00 and 19:00). This type of data enables regulators and stakeholders to understand how the portfolio of selected measures contributes to program goals and assists decision-making for measures to be included in a geotargeted program.

187 CEE, Non-wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot Geotargeted Distributed Clean Energy Initiative Update Report, 2021

188 CEE, *Non-wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot Geotargeted Distributed Clean Energy Initiative Update Report*, 2021

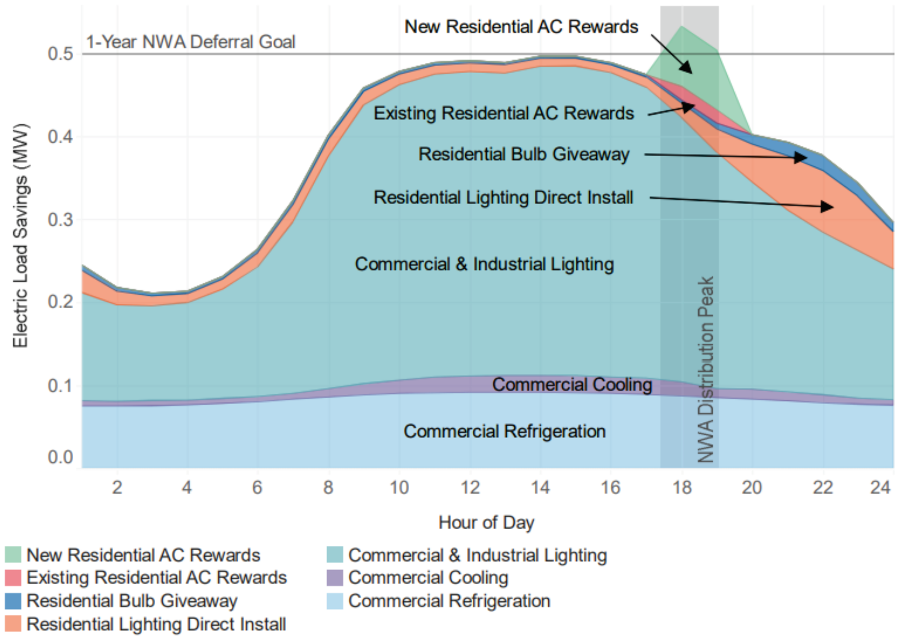

Figure 11-2. Expected measure performance – Xcel Energy's Geotargeted Distributed Clean Energy Initiative[189]

11.2.2 Evaluation of geotargeted program performance

Utilities can provide data on program effectiveness, community engagement activities, and budget to enable regulators and stakeholders to understand and assess the impact and outcomes of geotargeted programs implemented. These types of data can support decisions related to program continuity and identify any necessary changes to improve program performance to address changing grid need characteristics.

Program effectiveness: Data includes demand reduction (kW), including by customer class and measure implemented. For example, as part of its Brooklyn/Queens Demand Management Program,[190] Consolidated Edison reports quarterly on program performance, including peak load reduction achieved for customer program measures (e.g., energy efficiency, distributed generation, and distributed storage) and utility system measures (e.g., voltage optimization and energy storage located at a substation) and budget information (Table 11-6).

[189] CEE, Non-wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot Geotargeted Distributed Clean Energy Initiative Update Report, 2021
[190] NY DPS, Docket 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, August 15, 2014

Table 11-6. Brooklyn/Queens Demand Management Program performance data for Q2 2024[191]

BQDM PORTFOLIO	2024		
	Quarter 2	Year-to-Date	Program-to-Date
FINANCIAL ACTIVITY ($ M)			
[0] Expenditures			
Customer-sided	$ 0.35	$ 0.40	$ 108.39
Utility-sided	$ 0.38	$ 0.80	$ 24.98
Total Expenditures	**$ 0.72**	**$ 1.21**	**$ 133.37**
Program Cost Recovery	**$ 1.74**	**$ 3.48**	**$ 82.14**
CUSTOMER-SIDED PROGRAM ACTIVITY			
Energy Efficiency			
[1] Residential Direct Install			
Peak Hour kW reduction	-	-	4,930
[2] Bring Your Own Thermostat			
Peak Hour kW reduction	-	-	391
[3] Residential AC			
Peak Hour kW reduction	-	-	9
[4] Multifamily Energy Efficiency			
Peak Hour kW reduction	3	3	5,685
[5] Small-Medium Businesses Adder			
Peak Hour kW reduction	16	26	14,962
[6] Commercial & Industrial			
Peak Hour kW reduction	92	92	1,078
[7] NYCHA			
Peak Hour kW reduction	-	-	2,293
[8] DCAS			
Peak Hour kW reduction	29	29	567
Distributed Generation			
[9] Fuel Cell			
Peak Hour kW reduction	-	-	6,100
[10] Combined Heat & Power			
Peak Hour kW reduction	-	-	3,079
Energy Storage			
[11] Peak Hour kW reduction	-	-	4,000
Customer-Sided Portfolio kW reduction at Peak Hour	**141**	**150**	**43,095**
UTILITY-SIDED SOLUTIONS			
Conservation Voltage Optimization (CVO)	-	-	17,000
Distributed Energy Storage System	-	-	1,500
BQDM Total kW reduction at Peak	**141**	**150**	**61,595**

Consolidated Edison also analyzes hourly load reductions delivered by the program and provides information on load reductions delivered during peak system hours (Figure 11-3). For example, the utility reported 23 MW of load reduction from customer measures during the peak hour (9 p.m. to 10 p.m.).

[191] Consolidated Edison, *BQDM Quarterly Expenditures & Program Report*, Second Quarter 2024

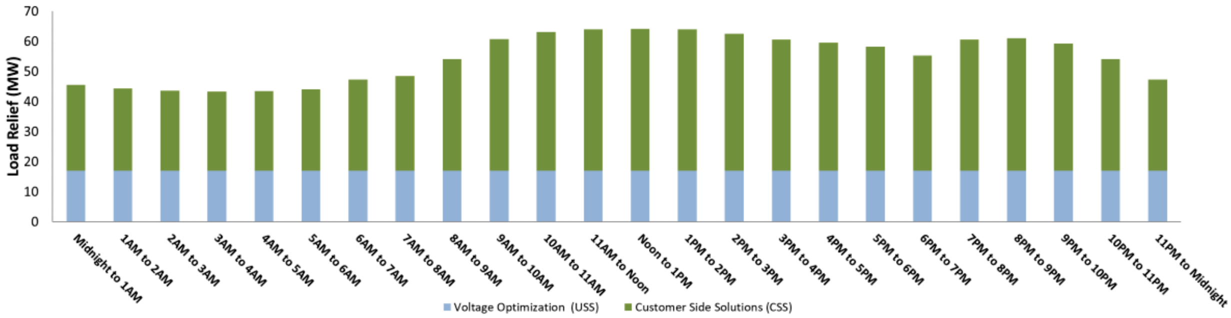

Figure 11-3. Brooklyn/Queens Demand Management Program load reduction data for Q2 2024[192]

Community engagement information can characterize utility efforts to engage local stakeholders during program design, implementation, evaluation, and improvements. Data can include types of community events held, target audiences, engagement goals, and event locations, venues, and outcomes. Data on community engagement efforts may provide regulators and stakeholders with information that informed the utility priorities and support program-related decisions.

Program budget information includes expenditures reported on a quarterly or yearly basis, with information for current period, annual period, and since the program start date. Utilities also can report program cost-effectiveness, including types of benefit-cost analysis tests and results. For instance, Central Hudson Gas & Electric Corporation in New York reports on cost-effectiveness of its Targeted Demand Management program annually. The data reported includes the test used and the results for the year (Table 11-7).

Table 11-7. Cost-effectiveness of Targeted Demand Management in 2023 – Central Hudson Gas & Electric Corporation[193]

BCA Test[a]	Results
Societal Cost Test	1.37
Utility Cost Test	1.35
Ratepayer Impact Measure	1.34

[a] Performed in accordance with Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 4.0. Case 16-M-0411 - In the Matter of Distributed System Implementation Plans, Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Distributed System Implementation Plan (filed on June 30, 2023).

Similarly, in Rhode Island, National Grid reported on the cost-effectiveness of its Tiverton Pilot using the Total Resource Cost test and providing historical data (Table 11-8).

[192] Consolidated Edison, *BQDM Quarterly Expenditures & Program Report*, Second Quarter 2024

[193] Central Hudson Gas & Electric, *Central Hudson Gas & Electric Corporation's 2023 Annual Report for the Targeted Demand Management (TDM) Program, a Central Hudson Non-Wires Alternative*, December 2023

Table 11-8. Cost-effectiveness of Tiverton Pilot, 2012-2017 – National Grid, Rhode Island[194]

System Reliability Procurement - Tiverton/Little Compton
Summary of Cost Effectiveness ($000)

	2012	2013	2014	2015	2016	2017	Overall
Benefits	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$668.5**	**$5,175.0**
Focused Energy Efficiency Benefits[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$497.6	$3,779.4
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$11.3	$713.3
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.4	$29.0
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$653.3
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$1,122.6**	**$4,138.3**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$804.0	$2,186.9
System Reliability Procurement Costs[6,7]	$86.8	$341.3	$373.5	$500.2	$331.0	$318.6	$1,951.5
Benefit/Cost Ratio	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**0.60**	**1.25**

Notes:

(1) Focused EE benefits in each year include the NPV (over the life of those measures) of all TRC benefits associated with EE measures installed in that year that are being focused to the Tiverton/Little Compton area.

(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.

(3) DR benefits represent the energy and capacity benefits associated with the demand reduction events projected to occur in each year.

(4) Deferral benefits are the net present value benefits associated with deferring the wires project (substation upgrade) for a given year in $2014.

(5) EE costs include PP&A, Marketing, STAT, Incentives, Evaluation and Participant Costs associated with statewide levels of EE that have been focused to the Tiverton/Little Compton area. For the purposes of this analysis, they are derived from the planned ¢/Lifetime kWh in Attachment 5, Table E-5 of each year's EEPP in the SF EnergyWise and Small Business Direct Install programs. These are the programs through which measures in this SRP pilot will be offered.

(6) SRP costs represent the SRPP budget which is separate from the statewide EEPP budget, as well as SRP participant costs. The SRP budget includes PP&A, Marketing, Incentives, STAT and Evaluation.

(7) All costs and benefits are in $current year except for deferral benefits.

(8) 2012-2016 numbers have been updated to reflect year end data. 2017 numbers reflect year end projections.

11.3 Best Practices

Best practices for sharing data on geotargeted programs include:

- Provide data that specifies program goals. For example, the utility can specify the distribution system assets the program is targeting for deferral, the estimated cost of those assets, and expected cost savings.
- Share data on the locational and temporal characteristics of the targeted grid need and program operational requirements. This includes identifying the specific location of the targeted distribution system assets and the months, days, and hours for the specified grid need.
- Preserve customer privacy and confidentiality. Some states specify confidentiality requirements, such as the California 15/15 rule discussed above. In other states, utilities can develop their own processes to safeguard customer information, such as aggregating data at a level that does not reveal customer-specific information and, where that is not possible, redacting data. Utilities also can protect customer confidentiality by executing nondisclosure agreements for third parties to access sensitive customer load data.
- Report data on eligible measures and expected measure performance. This includes data describing specific technologies the program will deploy and, if applicable, eligible customer classes, as well as kilowatt savings by measure and customer class.
- Regularly report on program effectiveness and progress. Data can be reported quarterly, including total demand reduction achieved and breakdown by measure and customer class.

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[194] National Grid, 2018 System Reliability Report, November 2017

- *Remove planning silos by integrating geotargeted program data in other planning analyses.* Direct utilities to analyze geotargeted programs as NWAs in distribution planning and program development and implementation processes, including filing methods and results.
- *Integrate geotargeted program outcomes data on future decision-making.* Use program data and lessons learned to inform future efforts and refine approaches, including participant recruitment and retention, incentive structure and levels, and types of program offerings.

12. Non-Wires Alternatives Procurements

Utilities can use DERs to provide grid services at specific locations on the distribution system to reduce, defer, or avoid the need for upgrades to infrastructure such as feeders and substations. NWAs can lower peak demand, address voltage issues, improve resilience, and reduce power interruptions through DERs sited on the utility system as well as at customer or community sites. Unlike geotargeted programs, NWAs rely on direct utility procurements or competitive solicitations of DERs, instead of customer programs administered by utilities or third parties.

Key inputs for NWA procurements that utilities can share include suitability criteria and technical and cost-effectiveness screens. Outputs include identified opportunities for NWAs, information on the procurement process, and NWA performance evaluation. Table 12-1 summarizes the types of data reported and their impacts on planning for each of these data categories.

Table 12-1. Summary of NWA procurement data and impacts on planning

Data category	Type of data reported	Impact of data on planning
Suitability screening	Criteria for determining whether NWAs are eligible to meet a specific grid deficiency — typically, project type, timing of the grid need, and cost threshold for a viable solicitation process	Identifies whether NWA processes and technologies are practical for addressing a specific grid need
Technical and cost-effectiveness screens	Methods and input assumptions for determining whether NWAs can resolve a grid need cost-effectively	Determines whether NWAs qualify to compete against the utility's traditional solution to meet a specific grid need
NWA opportunities	Detailed descriptions of grid needs for NWA solicitations, including location, timing, and magnitude of grid need	Prescribes how NWAs must perform and informs their selection and operation
Procurement process	Timeline, review process including bid evaluation criteria, bidding rules	Sets expectations for NWA providers on how the utility procures NWAs
Performance evaluation	Data requirements, data cleaning, and performance metrics	Validates utility assessment for achieving expected outcomes

12.1 Data Inputs

12.1.1 Suitability screening

The utility develops screening criteria to help identify distribution system needs that may be suitable for NWA solutions. Criteria include the project type (some grid needs may exclude NWAs from consideration), timing of the grid need (to ensure sufficient lead time for procurement), and cost of the traditional distribution infrastructure solution that otherwise would be built (a threshold below which the utility's time and effort for NWA analysis may not be justified).

Screening criteria help regulators and stakeholders understand key factors that affect whether an NWA could potentially address grid needs. Utilities can share proposed criteria for review by regulators and stakeholders, who may propose alternative criteria for consideration.

Criteria for project type may include the types of distribution infrastructure where NWAs may address grid deficiencies, operating conditions, and characteristics of the grid need. In Minnesota, for example, Xcel Energy limits NWAs to non-network and non-single bank substations under N-0 conditions.[195] Grid need characteristics may be as general as reliability[196] or be specific such as thermal overloads and voltage issues.[197] Utilities also may specify eligible grid services. For example, NV Energy identifies energy and peak demand reductions and load shifts as acceptable services that NWAs can provide.[198] In addition, utilities can include criteria on the scope of the grid need. Xcel Energy, for example, only allows NWAs to address grid needs that occur for fewer than 5,840 hours a year.[199]

Timing criteria can include both the minimum and maximum time until the utility must address a grid need. The minimum timeline reflects the time required for contracting, installing, and evaluating an NWA. NWA projects may not be feasible if a utility anticipates grid needs in the short term. The minimum timeline may depend on the affected part of the distribution system. Consolidated Edison's minimum timeline for projects at the feeder level is 18 months— half as long as the 36 months for projects on a major circuit or substation (Table 12-2). The maximum timeline generally reflects the length of the planning period in which the utility has identified grid constraints.[200] [201]

Minimum project cost thresholds address whether it is practical for the utility to conduct an NWA solicitation. As with timelines, utilities can differentiate cost criteria based on the part of the distribution system in question. Consolidated Edison, for example, offers NWA opportunities for planned utility projects at the feeder level that cost at least $450,000, but does not set a cost minimum for substation-level projects (Table 12-2).[202] Other utilities provide a single minimum project cost, such as Ameren's $3 million threshold.[203]

[195] Xcel Energy, Minnesota, Integrated Distribution Plan 2024-2033, Appendix B1Grid Modernization, November 2023
[196] Central Hudson Electric & Gas, Non-Wires Alternatives Opportunities
[197] NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
[198] NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
[199] Xcel Energy, Minnesota, Integrated Distribution Plan 2024-2033, Appendix B1Grid Modernization, November 2023
[200] NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
[201] Xcel Energy, Colorado, Distribution System Plan, May 2022
[202] Consolidated Edison, Distribution System Implementation Plan, June 2023
[203] Ameren Illinois, Multi-Year Integrated Grid Plan, January 2023b

Table 12-2. Consolidated Edison NWA suitability criteria[204]

Criteria	Potential Elements Addressed	
Project Type Suitability	Project types include Load Relief or Load Relief in combination with Reliability.	
Timeline Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• 36 to 60 months
	Small Project (Projects that are feeder level and below)	• 18 to 24 months
Cost Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• No cost floor
	Small Project (Projects that are feeder level and below)	• Greater than or equal to $450,000

Utilities can describe how they prioritize acquisition of NWAs that pass suitability screens. NYSEG, for example, prioritizes NWA acquisition based on forecasted timing of the associated grid need.[205] SDG&E uses metrics for cost-effectiveness, uncertainty of the grid need forecast, and likelihood that the utility can source NWAs.[206] Transparency into how utilities prioritize NWA procurement helps regulators, stakeholders, and bidders for NWA contracts understand the order in which the utility will acquire NWAs offered in utility solicitations.

12.1.2 Implementation and cost-effectiveness screens

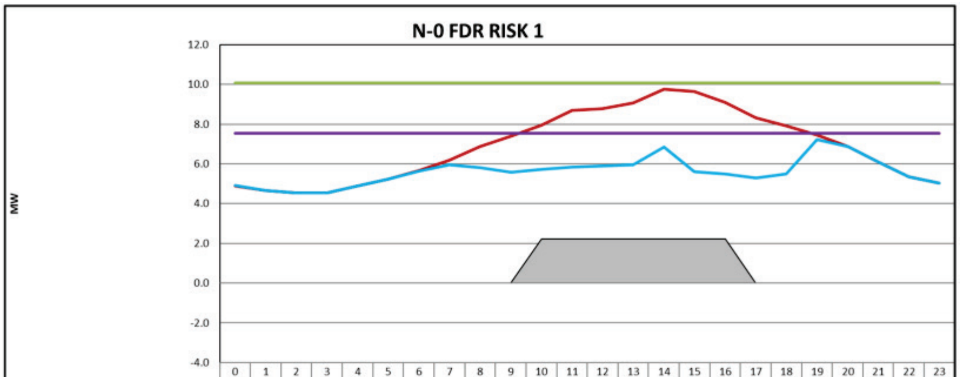
Utilities apply technical and cost-effectiveness screens to determine whether to pursue NWAs they have deemed suitable for known grid needs.

Technical screens include eligible technologies, modeling tools, and key decisions in modeling NWA performance. NV Energy, for example, describes how its NWA Screening Analysis Tool considers the impact of solar PV, battery storage, energy efficiency, demand response, and conservation voltage reduction on distribution system constraints.[207] The utility also documents assumptions on the maximum installed AC PV capacity (5 MW) and maximum load reductions from energy efficiency (2%) that it uses in the screening tool. In addition, the utility presents the capacity of each DER selected by the screen tool.

Transparency of utility assumptions in technical screens helps regulators and stakeholders understand factors that influence screening results and potentially propose alternative screening criteria. In its 2023 Integrated Distribution Plan for Minnesota, Xcel Energy describes its assumed 25% error in the peak forecast when assessing NWA solutions.[208] Figure 12-1 illustrates how this assumption affects the

204 Consolidated Edison, Distribution System Implementation Plan, June 2023
205 New York State Electric and Gas, Non-Wires Alternatives
206 San Diego Gas & Electric, 2023 Grid Needs Assessment and Distribution Deferral Opportunity Report, August 2023
207 NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
208 Xcel Energy Colorado, Distribution System Plan, May 2022

screening process. The utility assesses NWA performance (blue line) relative to 75% (purple line) of a feeder's capacity limit (green line). This forecast error assumption increases the energy and demand reductions required for NWAs. Xcel Energy also documents characteristics of the technologies it includes in the technical screen, including battery roundtrip efficiency.[209]



	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Need Shape (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder Limit (MW)	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Feeder Load (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.7	6.2	6.9	7.4	8.0	8.7	8.8	9.1	9.8	9.7	9.1	8.3	7.9	7.5	6.9	6.1	5.3	5.0
Forecast Uncertainty Margin (MW)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Feeder Load With NWA (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.6	5.9	5.8	5.6	5.7	5.8	5.9	5.9	6.9	5.6	5.5	5.3	5.5	7.2	6.9	6.1	5.3	5.0
Solar Generation (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3	-1.1	-1.8	-2.2	-2.9	-2.9	-3.1	-2.9	-2.6	-2.1	-1.5	-0.9	-0.2	0.0	0.0	0.0	0.0
Battery State of Charge (MWh)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03

Figure 12-1. Load profile for at-risk feeder in Xcel Energy Minnesota 2023 Integrated Grid Plan[210]

For cost-effectiveness screens, utilities can report discount rates and benefit and cost assumptions.[211] [212] [213] Transparency into these assumptions helps regulators and stakeholders validate utility decisions and propose alternative assumptions and methods. Utilities also can summarize the expected net benefits (see Table 12-3) and compare them to the cost of traditional solutions. The summaries make clear what costs and benefits drive the cost-effectiveness determination. For additional details on cost-effectiveness data that utilities can share in distribution system plans, see Chapter 9, Cost-Effectiveness Evaluation for Investments.

[209] Xcel Energy Colorado, Distribution System Plan, May 2022
[210] Xcel Energy Colorado, Distribution System Plan, May 2022
[211] Xcel Energy Colorado, Distribution System Plan, May 2022
[212] NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
[213] PGE, 2022 Distribution System Plan, Chapter 6. Non-wires solutions, 2022b

Table 12-3. Summary of NWA net benefits in Xcel Energy's Integrated Grid Plan for Minnesota[214]

Cost/Benefit Category	Incremental Impact
Energy Generation	$ 400,266
Generation Capacity + MISO Reserves	$ 122,602
Transmission Capacity	$ 5,830
Deferral Benefit	$ 627,936
GHG Emissions + Other Environmental	$ 623,658
Solar Cost	$ (504,285)
Battery Cost	$ (118,130)
Interconnection Fees	$ (34,000)
Total Benefit	**$ 1,780,292**
Total Cost	**$ (656,415)**
Net Impact	**$ 1,123,876**

12.2 Data Outputs

12.2.1 NWA opportunities

Utilities can identify and describe which deficiencies listed in the grid needs assessment will be included in NWA solicitations. Utilities can provide these descriptions in distribution system plans as well as in requests for proposals. The descriptions provide data on the context, timing, and magnitude of the grid need (see Table 12-4). These data convey how the NWA must perform to meet specific grid needs and help project developers and DER aggregators assemble a portfolio of NWAs. For example, energy and demand reduction requirements can inform the size and dispatch strategy for battery storage. Locational information such as feeder IDs and names helps developers access hosting capacity through utility-published maps and associated data. Data on the timing of the grid need sets expectations for participation by customers hosting DERs. In addition, the maximum number of events that a utility may call for demand response, for example, could affect a customer's willingness to participate.

[214] Xcel Energy, Colorado Distribution System Plan, May 2022

Table 12-4. Data on grid need for NWA Request for Proposals[215] [216] [217]

Grid need context	Narrative description of project
	Location
	Substation/feeder names
	Voltage of affected equipment
	Count of customers by service class served by equipment
	Traditional utility investment that NWA could replace
	Contingency in which need arises (e.g., N-0 vs. N-1)
Magnitude of grid need	Maximum daily energy need
	Maximum MW needed
Timing of grid need	Date by which NWA must be in service to address need
	Number of years that NWA must resolve grid need
	Days of week in which event could occur
	Hours in which event could occur
	Event duration
	Maximum number of events per year
	Maximum number of consecutive days with events

12.2.2 Procurement process

Utilities generally procure NWAs through competitive bidding. Key elements of the procurement process that utilities can share include the procurement timeline, review process including bid evaluation criteria, and bidding rules. Figure 12-2 illustrates Xcel Energy's solicitation timeline and milestones for its Colorado service area. A clear timeline sets expectations for regulators and NWA vendors and creates accountability for utilities. Documentation of the utility's review process can include standards or metrics for evaluating proposals (e.g., cost-effectiveness methodology) and the role of an independent evaluator to review bids.[218] [219] Bidding rules can include the minimum size of the bid. National Grid, for example, includes a minimum bid size of 100 kW in its 2024 request for proposals for one of its substations.[220] In its 2023 Integrated Grid Plan, Hawaiian Electric describes how

[215] National Grid, Request for Proposal, October 2024b
[216] Hawaiian Electric, Integrated Grid Plan, May 2023
[217] Xcel Energy, Colorado, Distribution System Plan, May 2022
[218] Xcel Energy, Colorado, Distribution System Plan, May 2022
[219] Hawaiian Electric, Integrated Grid Plan, May 2023
[220] National Grid, Request for Proposal, October 2024b

it plans to adapt to situations in which bids do not address the entire grid need, the NWA contractor does not install the planned measures, and the NWA does not operate as needed. By establishing how they plan to handle such contingencies, utilities can assure regulators that they are prepared to handle unexpected outcomes from NWAs and address grid needs.

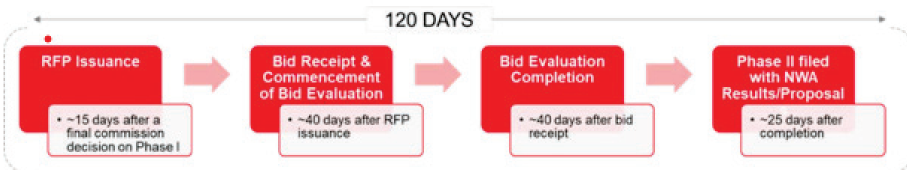


Figure 12-2. Xcel Energy Colorado NWA solicitation process[221]

12.2.3 Performance evaluation

Data on NWA performance evaluation can include data requirements, data cleaning, and performance metrics. For example, Consolidated Edison's performance verification plan states that it requires real power production, voltage, amperage, and power factor among other data points to evaluate the impact of NWAs.[222] The utility also describes how it excludes the lowest 5% of hourly generation measurements when calculating average reductions in energy needs due to distributed generation during grid need hours. Reporting on such methodological assumptions helps regulators and stakeholders assess utility decisions and suggest alternative assumptions or methods for consideration. Performance metrics defined before NWA solicitations are issued can promote successful implementation by helping NWA vendors prepare to submit solutions that achieve the desired outcomes.[223] Consolidated Edison, for example, provides metrics for distributed generation and storage, including Average Event Load Reduction (see Figure 12-3).[224]

$$AELR_M = \left(\frac{\sum_{i=E_{start}}^{i=E_{end}} kWh_i}{E_{end} - E_{start}} \right) + EC_M$$

Where,

kWh_i	Electricity discharged per hour interval i (charging will result in negative kWh values)
i	Each hourly interval during NWS Event
M	NWS Event Day
EC_M	Energy Charged on Event Days

Figure 12-3. Metric used for battery storage performance for Consolidated Edison NWAs

221 Xcel Energy Colorado, Distribution System Plan, May 2022
222 Consolidated Edison, Performance Verification Plan, May 2022
223 National Grid, Request for Proposal, October 2024b
224 Consolidated Edison, Performance Verification Plan, May 2022

12.3 Best Practices

Best practices for data sharing on NWA procurements include:

- Establish appropriate lead times for grid needs identification, NWA planning, procurement, and deployment.
- Conduct inclusive and collaborative stakeholder engagement processes to align NWA procurement with community needs and public interests.
- Establish transparent rules for NWA ownership and operation.
- Clearly describe criteria for NWA suitability, informed by stakeholder input.
- Document methods and assumptions for technical and cost-effectiveness screening.
- Present detailed information on NWA opportunities, including:
    - Locational information (e.g., feeder ID)
    - Timing of grid need (e.g., months and hours)
    - Magnitude of grid need (e.g., MW of demand reduction required).
- Provide adequate grid data to developers for competitive solicitations for NWAs.
- Use a technology-agnostic portfolio approach for NWAs.
- Consider contingency planning for procured NWA projects (e.g., acquire excess NWA capacity) to reduce risk associated with non-performance.
- Implement standard pro forma agreements for NWAs.
- Offer vendor pre-qualification options to reduce procurement timeline.
- If viable NWA bids are insufficient to meet the identified grid need, consider combining NWAs with utility infrastructure upgrades to meet the same need at lower cost compared to the standalone utility solution.
- Provide a performance evaluation framework that includes data requirements and performance metrics.
- Use data and lessons learned from completed NWA procurements and implementation to inform future efforts and refine approaches.

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APPENDIX A. Organizations Interviewed

Utilities
National Grid, New York
Portland General Electric
Public Service of Colorado

Public Utility Commissions
Illinois Commerce Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
New York Department of Public Service
Rhode Island Public Utilities Commission

State Energy Offices
Massachusetts Department of Energy Resources
Minnesota Department of Commerce