A White Paper

Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support

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List of Acronyms

AMI	advanced metering infrastructure
BTM	behind-the-meter
CAIDI	Customer Average Interruption Duration Index
DER	distributed energy resource
DERMS	distributed energy resource management systems
DSP	distribution system planning
EV	electric vehicle
EVSE	electric vehicle supply equipment
FERC	Federal Energy Regulatory Commission
FTM	Front-of-the-meter
HVAC	heating, ventilation, and air conditioning
IGP	integrated grid planning
IRP	integrated resource planning
NREL	National Renewable Energy Laboratory
NWA	non-wires alternative
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
VAR	volt-amps reactive

Executive Summary

Distribution system planning (DSP) is experiencing monumental shifts in consumer needs and expectations. Opening DSP to stakeholders is a challenging but critical endeavor, and innovative solutions are needed for utilities to effectively communicate the costs and risks of planning decisions and facilitate meaningful stakeholder engagements and education around DSP. This white paper is the culmination of interviews with utility representatives coordinated over 5 months by the National Renewable Energy Laboratory (NREL) and Kevala, Inc. (Kevala) to better understand the current state, challenges, and opportunities in distribution capacity planning.[1]

The integrated grid planning[2] (IGP) framework is a good start to acknowledging that a new process is needed to address such challenges. The IGP extends bulk system integrated resource planning (IRP) to distribution networks calling for more granular modeling and forecasting, deeper modeling of transmission and distribution system interactions, and improved modeling of uncertainty and risk. Utilities are moving toward an IGP framework to manage uncertainty in the size, location, and timing of future load growth, as well as to enable innovative and cost-effective solutions to address future capacity needs. The business-as-usual distribution planning alternative may not be fully prepared to make equitable least-cost and cost-causation assessments. Many examples are common today:

1. **Utility departments do not operate with fully integrated data stores and technologies.** A technology example is distribution operations software such as distributed energy resource management systems (DERMS) and flexible interconnection methods,[3] which are not considered when managing DSP constraints. A data store example is customer time-series data, which are not commonly used in the DSP process.
2. **Distribution capacity planning horizons.** Planning horizons are typically 5 years, but they can range from 3 to 10 years depending on the project. Such short time horizons may not align with state and federal policies—which are designed to meet long-term societal needs—and they may lead to planning decisions that risk becoming obsolete and unable to meet the rapid adoption of DERs.
3. **Value of DERs:** DER tariffs have been successful at encouraging DER deployment in many states, but they do not often reflect the locational value and impact of DER and their effect on shifting costs[4] is not well understood.
4. **Deferral Value of Non-Wires Alternative (NWA) Frameworks:** We define NWAs as any capacity solution that does not require wire investments (e.g., a transformer upgrade). Most typically they are solutions involving battery energy storage, demand response, or

[1] Distribution capacity planning is a subset of distribution system planning focuses on the capacity investments needed to meet demand without thermal overloading. This white paper focuses on distribution *capacity* planning.
[2] Organizations with IGP frameworks include the Electric Power Research Institute (EPRI) and the Smart Electric Power Alliance (SEPA). ICF, the National Association of Regulatory Utility Commissioners, the National Association of State Energy Officials, and the National Association of Regulatory Utility Commissioners are either developing or investigating IGP frameworks.
[3] Refers to the number of options that are available for DER interconnection and in particular to options that involve real and reactive power control.
[4] The cost shift can be attributed to the difference between the true value of DERs and DER tariffs.

energy efficiency. NWA capacity solutions are evaluated using the deferral value of capital investments and typically target larger multi-million-dollar distribution capacity projects. To date, market response to NWA opportunities has been limited.[5]

5. **Interconnection Costs:** Business-as-usual DSP may be unable to equitably allocate interconnection costs. Today, interconnection costs for DER prosumers and developers could include grid upgrades that may not be aligned with the value and impact of DER on the grid, and/or consider a holistic picture of the impact of these grid upgrades to the system.

For this study, common features of current DSP were observed among the utilities interviewed and are illustrated in Figure ES-1.

Capacity constraints are typically predicted using a deterministic load and distributed energy resource (DER) forecasting process looking at 3- to 10-year time horizons, and at the "substation" or circuit-level spatial resolution. The most common concern raised by the utilities for this study was low geospatial resolution forecasts. These "peanut-butter spread" forecasts[6] result from a top-down forecast for load and DER technologies with disaggregation methods that may not accurately capture locational adoption trends and differences in the underlying building stock and customer characteristics. This lack of granularity greatly reduces a planner's ability to anticipate relative grid needs and target solutions in areas with expected future rapid load and/or DER growth.

Low-cost solutions and new infrastructure replacements are typically used to address capacity constraints, while non-wires alternative (NWA) solutions are limited by technical criteria, timing, project size and economics based on the deferral value of capital investments. Fixed annual capital budgets, along with competition for these limited funds between departments (e.g., between planning and operations), or within departments (e.g., capacity projects in different utility planning zones) for project priority can make it difficult to provide transparency in the project selection process. The current planning process has several gaps and opportunities as illustrated in the future distribution capacity planning framework in Figure ES-1, which are primarily in the following areas:

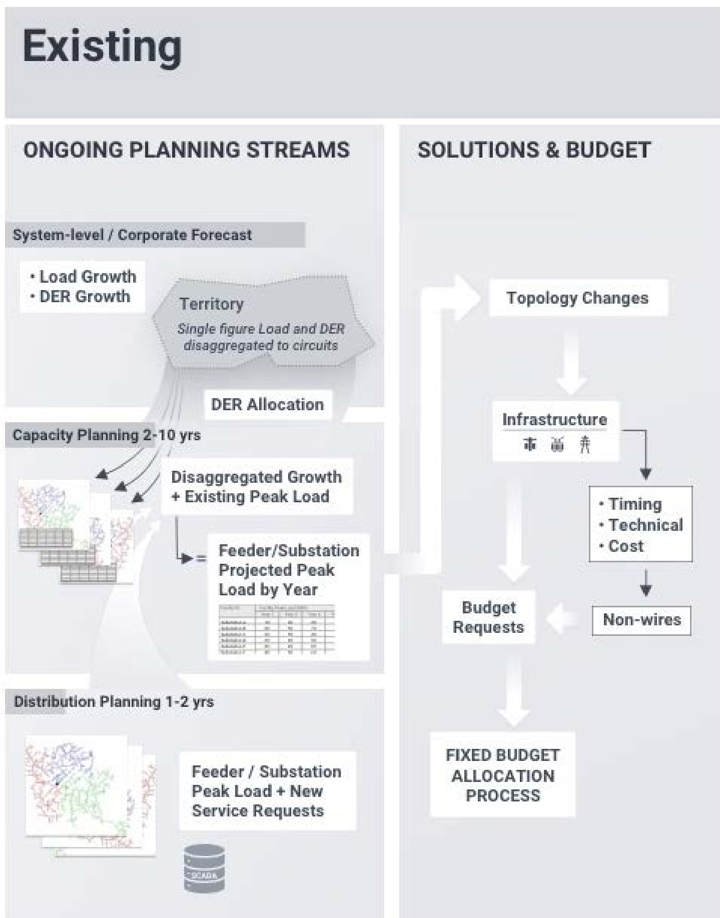
- Longer-term (>15 years) capacity planning horizons that align with policy goals
- Customer-driven, time-series and geospatially granular load and DER adoption forecast methods
- Use of scenario and probabilistic methods to better capture uncertainty and manage risk
- Use and integration of data and technologies across utility departments
- A more holistic view of objectives and metrics for evaluating distribution planning solutions that include not only reliability and economics but also address resiliency, equity, and carbon emissions

[5] For a review of NWA frameworks, see Pacific Energy Institute, *NWA Opportunity Evaluation Survey of Current Practice*, prepared for Hawaiian Electric Co., March 2020. https://pacificenergyinstitute.org/wp-content/uploads/2020/04/NWA-Opportunity-Evaluation-Survey-final-Mar-2020.pdf.

[6] The colloquial term "peanut butter spread" is commonly used by utility engineers to describe taking system-level load or DER forecasts and uniformly distributing or disaggregating those forecasts to substation and circuit-level resolution.

Forward-looking decision support methods for DSP could be developed that align with the forward-looking nature of IRP and IGP frameworks. For example, IGP with decision support tools could be used to proactively assess how long-term distribution capacity costs would change with and without managed electric vehicle charging, DERs, and other load management options. IGP could also help entities undertaking DSP to equitably allocate DER or electric vehicle interconnection costs.

Objective metrics and decision-making frameworks to weigh the importance of each planning criteria should be clearly defined to align corporate utility goals with external stakeholders and regulatory bodies. New holistic and technology-agnostic metrics or planning criteria (e.g., for hosting capacity, resilience, equity, energy justice, energy efficiency, and distribution resource adequacy) are needed that can be applied with confidence to utility investments and non-wires solutions. Ultimately, the industry would benefit from having a distribution planning guide that can serve as a reference and can describe best practices on conducting distribution planning activities, without prescribing a “one-size fits all” approach to distribution planning, since distribution grids across country have significant differences in their structure and operations.



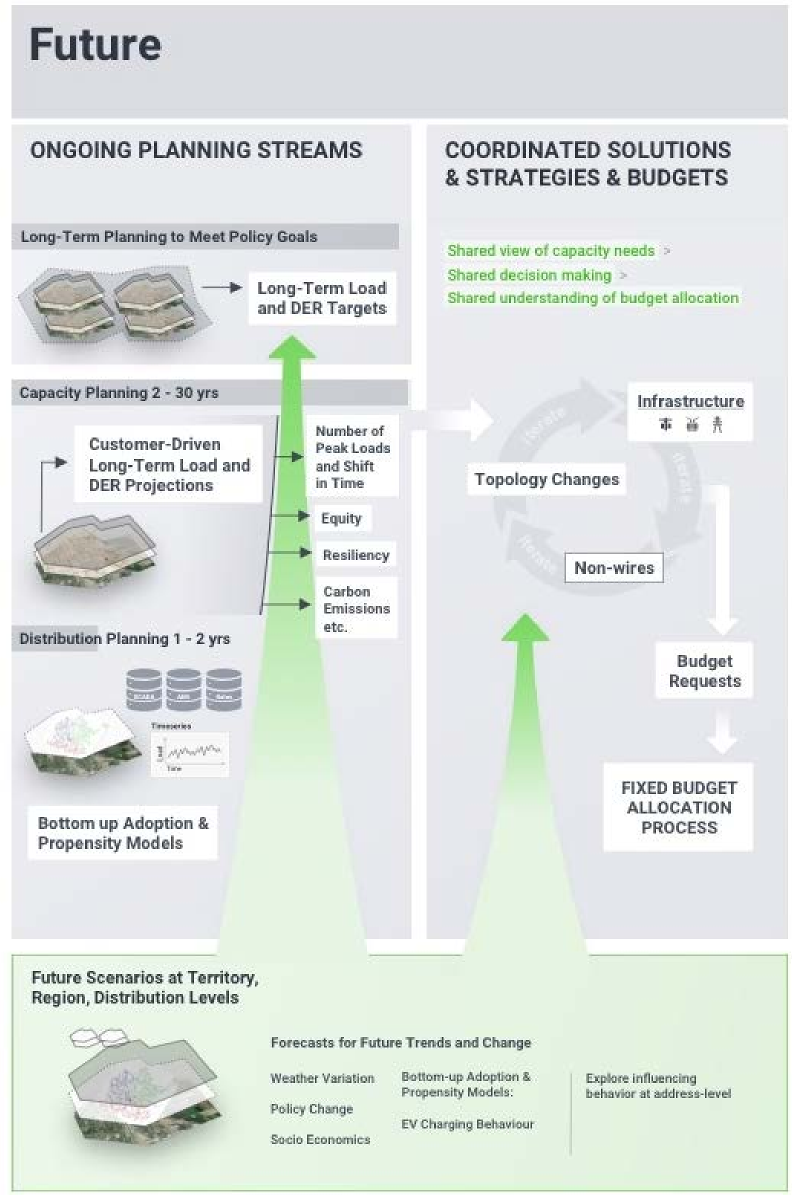


Figure ES-1. Existing distribution capacity planning framework where grid investments and deferral opportunities are determined by peak load forecasts in 2–10 years (left) and future distribution capacity planning framework with scenarios and probabilistic bottom-up load and DER adoption models, as well as multiple objectives and metrics driving the evaluation of distribution capacity solutions (right).

BTM is behind-the-meter. SCADA is supervisory control and data acquisition. AMI is advanced metering infrastructure.

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Introduction

Distribution utilities and engineers are experiencing monumental shifts in consumer needs and expectations. Characterizing future native[7] loads as compared to net load demand for long-term capacity planning is especially difficult, as consumers are increasingly adopting prosumer technologies. Front-of-the-meter (FTM) and behind-the-meter (BTM) distributed energy resources (DERs), such as combined heat and power, solar photovoltaics, ground-mounted and residential-scale storage, energy efficiency and demand response, electric vehicles (EVs) and EV supply equipment (EVSE), and other electrification technologies, such as heat pumps, increase the complexity of the consumer load profile landscape for planning. Also, for some utilities, the opportunity for DER owners to engage in energy market settlements enabled by Federal Energy Regulatory Commission (FERC) Order 2222[8] and other wholesale market constructs further challenges utility forecasting of net load. Though market data may increase data availability, data management systems are not well integrated into utility planning processes and are not easily accessible by all departments.

Some utilities have considerable planning activity already targeted at managing growth from prosumer technologies. Meanwhile, policymakers, bulk power system planners, consumers, renewable energy developers, EV fleet managers, aggregators, progressive utilities, and community stakeholders have all increased their engagement in the distribution system planning (DSP) process. Opening DSP processes to stakeholders is a challenging but critical endeavor, and innovative solutions are needed for utilities to effectively communicate the costs and risks of planning decisions, and facilitate meaningful stakeholder engagements and education around DSP.

The integrated grid planning[9] (IGP) framework is a good start to acknowledging that a new process is needed to address such challenges. The IGP framework extends bulk system integrated resource planning (IRP) to distribution networks calling for more granular modeling and forecasting, deeper modeling of transmission and distribution system interactions, and improved modeling of uncertainty and risk. Utilities are moving toward an IGP framework to manage uncertainty in the size, location, and timing of future load growth, as well as to enable innovative and cost-effective solutions to address future capacity needs. The business-as-usual distribution planning alternative may not be fully prepared to make equitable least-cost and cost-causation assessments. Many examples are common today:

1. **Utility departments do not operate with fully integrated data stores and technologies.** A technology example is distribution operations software such as distributed energy resource management systems (DERMS) and flexible interconnection

[7] A native load is the load without any DER. It is also sometimes referred to as a gross, true, unmasked, or phantom load.
[8] FERC Order 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, September 2020. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf.
[9] Organizations with IGP frameworks include the Electric Power Research Institute (EPRI) and the Smart Electric Power Alliance (SEPA). ICF, the National Association of Regulatory Utility Commissioners, the National Association of State Energy Officials, and the National Association of Regulatory Utility Commissioners are in the process of developing or are investigating IGP frameworks.

methods,[10] which are not considered when managing DSP constraints. A data store example is customer time-series data, which are not commonly used in the DSP process.

2. **Distribution Capacity Planning Horizons:** Planning horizons are typically 5 years but can range from 3 to 10 years depending on the project. These short time horizons may not align with state and federal policies, which are designed to meet long-term societal needs and the misalignment may lead to planning decisions that risk becoming obsolete and unable to meet the rapid adoption of DERs.
3. **Value of DERs:** DER tariffs have been successful at encouraging DER deployment in many states, but they do not often reflect the locational value and impact of DER and their effect on shifting costs[11] is not well understood.
4. **Deferral Value of Non-Wires Alternative (NWA) Frameworks:** We define NWAs as any capacity solution that does not require wire investments (e.g., a transformer upgrade). Most typically, they are solutions involving battery energy storage, demand response, or energy efficiency. NWA capacity solutions are evaluated using the deferral value of capital investments, and they typically target larger multimillion-dollar distribution capacity projects. To date, market response to NWA opportunities has been limited.[12]
5. **Interconnection Costs:** Business-as-usual DSP may be unable to equitably allocate interconnection costs. Today, interconnection costs for DER prosumers and developers could include grid upgrades that may not be aligned with the value and impact of DER on the grid, and/or consider a holistic picture of the impact of these grid upgrades to the system.

Though IGP provides a framework for addressing these challenges, it increases the resource requirements of DSP activities. Improved modeling, data and information requirements, storage and exchange, and decision support methods are needed to create a distribution planning process that supports the IGP framework, identifies distribution capacity needs and NWA solutions, and meets long-term policy-driven decarbonization goals.

In recent years, a rich body of research has emerged on distribution capacity expansion planning.[13] Collectively, this research can help utility planners choose between low-cost operational changes,[14] new wire investments, NWAs, managed EV charging, and EVSE placement[15] to determine the least-cost, most reliable capacity solutions under load and DER growth uncertainty. However, distribution capacity planning tools are not yet fully deployed that

[10] Refers to the number of options that are available for DER interconnection and in particular to options that involve real and reactive power control.

[11] The cost shift can be attributed to the difference between the value and impact of DERs and DER tariffs.

[12] For a review of NWA frameworks, see Pacific Energy Institute, *NWA Opportunity Evaluation Survey of Current Practice*, prepared for Hawaiian Electric Co., March 2020. https://pacificenergyinstitute.org/wp-content/uploads/2020/04/NWA-Opportunity-Evaluation-Survey-final-Mar-2020.pdf.

[13] For a review of distribution capacity expansion models see Georgilakis, P., N. Hatziargyriou, "A Review of Power Distribution Planning in the Modern Power Systems Era: Models, Methods and Future Research," *Electric Power Systems Research* 121 (April 2015): 89–100. https://doi.org/10.1016/j.epsr.2014.12.010.

[14] Low and no-cost operational changes are often the first alternative considered in DSP, and they may include phase balancing, operational switching and permanent load shifts to neighboring equipment

[15] EVs and EVSE cause load growth, so it may seem unusual to classify them as solutions for load management. Here we are referring to managed charging for EVs and the ability to control the location of new EVSE to minimize capacity costs.

are interoperable with utilities’ complex planning systems and that have outputs and reporting capabilities designed to be shared transparently with stakeholders.

This white paper is the culmination utility interviews coordinated over five months by the National Renewable Energy Laboratory (NREL) and Kevala, Inc. (Kevala) to better understand distribution capacity planning challenges. The interviews covered all aspects of capacity planning including load and DER forecasting, criteria for assessing system constraints, solution types, and organizational and decision-making structures. Our intent is to provide insight into distribution capacity planning decision support needs for utilities and the increasing number of stakeholders involved, from state and regulatory agencies to community and solution providers with interest in increasing their understanding in the distribution capacity planning process.

The white paper is organized as follows:

- **Current Distribution Capacity Planning Process -** We first describe common patterns in the distribution capacity planning process among the 13 interview participants.
- **Gaps and Opportunities: An Advanced Planning Architecture -** We then describe gaps and opportunities that an advanced planning architecture could address.
- **Decision Support Methods -** Lastly, we propose important capabilities and methods for new decision support tools to support the distribution capacity planning needs of the future.

Throughout this white paper, "utility highlights" are listed. These highlights should not be viewed as recommendations, but they do showcase current utility efforts to address the challenges we discuss.

Current Distribution Capacity Planning Process

This section illustrates common features of the current distribution planning process among the utilities interviewed, starting with how utilities forecast future load and DER growth and how they determine future capacity needs. The forecasting process is followed by the solutions and decision-making framework that distribution utilities use in their annual distribution capacity planning process.

Deterministic Load and DER Forecasting

Distribution capacity planning is an annual process that aims to identify demand capacity needs relative to system constraints over the next 3-10 years of forecasted growth. Some utilities extend their planning horizon to 10 years or more, and they face large financial risk with the amount of uncertainty beyond 5-year horizons. A 5-year horizon is typically used because it has enough lead time for project development and because distribution planning typically considers only one or a few planning scenarios. Longer planning horizons would require more scenarios and probability assessments to address uncertainty (e.g., technological breakthroughs and changing consumer behaviors).

The 5-year planning scenario uses a combination of top-down and bottom-up methods to forecast load at the circuit level (i.e., the substation and feeder main conductor immediately downstream of the substation). To characterize the baseline load, planners begin with recent annual peak loads recorded by supervisory control and data acquisition (SCADA) measurements, or other monitoring equipment where SCADA is lacking. These peaks are either weather-normalized or selected to be representative of worst-case summer and/or winter peak load. Next, a bottom-up estimate[16] of increased circuit loading is developed using new interconnection service requests for large customers and other known development projects (e.g., new residential subdivisions). The characterization of the existing peak load is represented in the "Distribution Planning 1-2 yrs" (bottom left) box in Figure 1.

Distribution planners also consider a top-down corporate forecast for load growth that is disaggregated to substations and feeders, as the "System-level / Corporate Forecast" (top left) box in Figure 1 shows. Although corporate or system-level forecasts typically account for the multiple scenarios used in transmission planning, it is common to use a more moderate forecast scenario for DSP. The down-selection of scenarios for the distribution capacity planning process is primarily due to the time-consuming annual capacity planning process needed for all distribution substations and feeders. We refer to the load and DER forecasting as "deterministic" because the output (i.e., the expected future peak load number by feeder and substation) is fully determined by the initial value of weather normalized existing peak load combined with the exogenous load and DER growth values, whereas probabilistic (or stochastic) models and scenario-based planning incorporate randomness and multiple runs in their approach.

[16] Developer load estimates may be inaccurate. Future loads may be predicted during tight timelines using panel size or BTM-connected kVA. Doing so can cause large overestimations in the load.

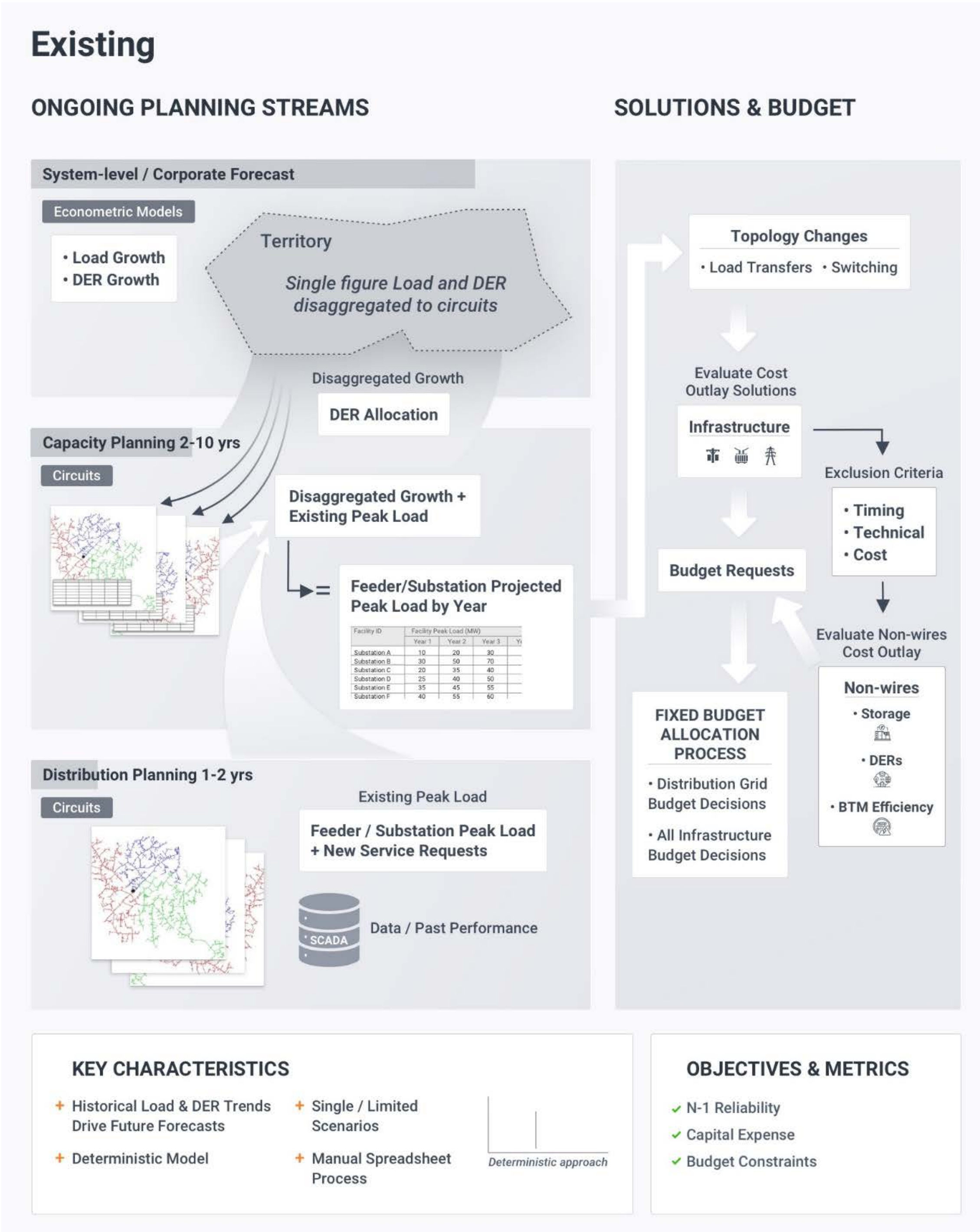

Figure 1. Existing distribution capacity planning framework in which grid investments and deferral opportunities are determined by what the peak load is expected to be in the following 2–10 years

Although many utilities only forecast load, more-advanced utilities have begun to forecast native load growth and additional demand modifiers (e.g., solar photovoltaics, storage, and EVs) separately. For such utilities, the native load and DER (or demand-side modifiers) growth from the top-down forecast are disaggregated down to substations and circuits using different econometric disaggregation techniques that result in an aggregate load shape for each DER technology at the substation and/or feeder levels. The sophistication of these techniques ranges from simple allocation methods based on ratios such as percentage of sector-level consumers or energy consumption at the substation or feeder, to more advanced adoption propensity models at the ZIP code or even at the site level.

The most common concern raised by the utilities in our interviews is the issue of low geospatial resolution forecasts. These "peanut-butter spread" forecasts[17] result from a top-down forecast for load and DER technologies with disaggregation methods that may not accurately capture locational adoption trends or differences in the underlying building stock and customer characteristics. This lack of granularity greatly reduces a planner's ability to anticipate relative grid needs and target solutions in areas with expected future rapid load and/or DER growth. For example, top-down forecasts and simple disaggregation techniques may result in relatively homogenous adoption forecast of EVs and associated direct current fast charging stations across utilities distribution assets. However, in reality, EV load growth can be extremely heterogenous, causing high loading on some distribution assets and less on others. Moreover, there are often internal or external requirements that distribution load forecasts match up with system-level corporate load forecasts, leading to a difficult problem for planners to solve given the heterogeneity of local distribution system peak loads. DSP planners might compensate for this uncertainty with worst-case scenarios (e.g., all chargers turned on during daytime peaks) to study the prudency of the investment at the localized asset level, but doing so creates an inconsistency with the top-down forecast.

Existing Solutions to Distribution Capacity Needs

After completing the new peak load forecast for the following 5 years, transformer bank and circuit expansions are identified where load is expected to exceed their planned capacity during normal and N-1 contingency scenarios.[18] The result is most often a spreadsheet of distribution substations and feeders and their expected peak load and capacity deficiency for the next 5 years (see the "Capacity Planning 2 – 10 yrs" box in Figure 1). Though transformer life, insulation condition, and asset criticality are typically tracked, there is limited coordination between the capacity planning and asset management teams, and distribution assets can often be run to failure.

[17] The colloquial term "peanut butter spread" is commonly used by utility engineers to describe taking system-level load or DER forecasts and uniformly distributing or disaggregating those forecasts to substation and circuit-level resolution.

[18] "N-1 contingency" refers to a situation where a discrete asset (e.g., substation transformer or distribution feeder) experiences a planned or unplanned outage, and the additional load must be picked up by neighboring equipment identified in the switching plan.

Once the capacity need has been predicted for every substation and feeder, the sequence of solutions that is considered is as follows:

1. **No Cost or Low-Cost Solutions:** New switches, load transfers, and phase balancing are considered first to manage a capacity constraint because these solutions are low cost.
2. **New Infrastructure Replacement:** Capital infrastructure expansion (e.g., transformer upgrades, reconductoring) are considered for all remaining constraints.

After the grid needs are identified and new infrastructure project costs are estimated, some utilities consider whether there are deferral opportunities using NWAs. Utilities use targeted criteria for all capital infrastructure expansion projects to identify good candidates for deferral opportunities. The following technical, timing and cost criteria are commonly used[19]:

- **Technical Criteria:** A common technical criteria for NWAs is that they can only be applied to investments that are "deferrable" when load is reduced. Wire investments made in response to new customer connections or to replace aging assets, for example, are not considered avoidable using DERs. Utilities have also found NWA solutions to be less applicable during N-1 contingencies.
- **Timing and Total Project Cost Criteria:** NWA solutions must be less expensive than wire solutions and must be executed in a specified time horizon. These timing and cost criteria typically have narrowed NWA solutions to capacity investments exceeding \$1–\$3 million with 3 years of lead time.

NWA solutions have faced several challenges regarding attempts to increase their market share, and they have often been restricted to front-of-the-meter storage and solar plus storage projects. Reasons that few NWAs come to fruition include:

1. The NWA solution is compared only to the functionality of the asset being deferred. For example, battery storage projects are compared to a transformer bank's capabilities, expecting the battery capacity to be available on demand when needed and often required to be under the full control of the utility. This reduces the potential for additional market revenue streams and values in which a battery could participate.
2. During NWA development, large load customer interconnection requests could be withdrawn, removing the need for an NWA.
3. BTM resources, aggregator solutions, demand response, and rates designed to encourage various DER or manage peak load are often not considered reliable or mature enough to provide firm capacity. Also, utilities commonly find that demand response and energy efficiency cannot provide enough load relief on their own to alleviate grid constraints, and so they require combined solutions with other technologies, such as solar or batteries.
4. NWA solutions are applied to projects with high investment costs.

[19] For a review of NWA frameworks, see Pacific Energy Institute, *NWA Opportunity Evaluation Survey of Current Practice*, prepared for Hawaiian Electric Co., March 2020. https://pacificenergyinstitute.org/wp-content/uploads/2020/04/NWA-Opportunity-Evaluation-Survey-final-Mar-2020.pdf.

Distribution Planning Decision-Making

After identifying potential capacity constraints and candidate solutions, utility decision makers must choose which projects to execute. Fixed annual capital budgets, along with competition between departments (e.g., planning and operations) for these limited funds or within departments (e.g., capacity projects in different utility planning zones) for project priority can make it difficult to provide transparency in the project selection process. Further, projects are not only evaluated for execution based solely on whether they have an identified capacity need—they are also evaluated based on highest priority of need. Due to budget constraints, a capacity solution required in 3 years would take priority over one needed in 5 years, and likewise a project to address an asset reaching 100% of its thermal safety ratings would take priority over one that merely exceeds a lower planning threshold for replacement. The prioritization process and metrics should provide perspective on utility and developer business objectives. Incorrect cost-causation attribution can impact DER development while NWAs can diminish utilities' rate base and earning potential.

Distribution capacity planners report in our interviews that it has been very challenging in recent years to engage with stakeholders on capacity planning and NWA topics. The infrastructure and NWA evaluations are managed on a project-by-project basis, with sometimes inconsistent data and criteria being applied across projects and unclear metrics being used for evaluation. Some inconsistency is difficult to avoid because the unique characteristics of NWA projects often require that traditional projects be reframed to support a reasonable evaluation. For example, NWAs may require 8,760 hourly loading data, increased planning horizons to capture deferral periods, and stack values from bulk grid services like avoided energy costs. These challenges result in a time-consuming process for utility staff, both in the engineering and regulatory departments. Before adopting changes in stakeholder engagement and NWA assessment, the changes should be balanced against the increases they may cause to project lead time requirements.

Gaps and Opportunities: An Advanced Planning Architecture

The current planning process has several gaps and opportunities. In this section, we highlight four opportunities for improving distribution capacity planning and laying the foundation for decision support tools. Figure 2 illustrates the gaps and opportunities of future decision-making methods, which are primarily in the following areas:

1. Long-term customer-driven load and DER adoption forecast methods
2. Use of scenario and probabilistic methods to better capture the uncertainty and manage risk
3. Use and integration of data across utility departments
4. A more holistic view of objectives and metrics for evaluating distribution planning solutions.

Long-Term Customer Load and DER Adoption Methods

Improved native load and net load forecasting represent the first opportunity to improve distribution capacity planning. DSP engineers face an increasing number of technologies that can affect the system native load and net load. Historical measurements from advanced metering infrastructure(AMI) and SCADA typically measure only net load, making it challenging to disaggregate DER and native load contributions. Moving forward, DERs, EVs, and EVSE will all cause uncertainty in the timing, size, and location of loads. More traditional loads will also increase as the residential, commercial, and industrial sectors electrify heating, ventilation, and air conditioning (HVAC) equipment and other equipment. Load and technology-specific spatial forecast tools provide an opportunity to manage the uncertainty. Though spatial load forecasting tools have been adopted by several utilities, solar, battery, and EV adoption models are more nascent. Spatial forecasting tools that consider all electrification technologies are needed.

Improved load and DER forecasting with customer-driven modeling also enables a more granular understanding and evaluation of customer programs and rate design. With the right incentives and good forecasts, utilities could incorporate expected changes to customer net loads resulting from these programs into the distribution capacity planning process. Also, a more granular understanding of the location-specific costs of serving different planning areas could inform the decision-making process when utilities are evaluating capacity planning solutions and working to equitably price interconnection costs.

Further guidance may be needed to align short-term planning goals with long-term policy goals. A long-term view (beyond 10 years) of capacity needs could help better meet the needs of aggressive electrification goals and provide more opportunities for assessing the value and impact of DERs to meet the expanding capacity needs in the distribution system. One obstacle for utilities is that changes in policies can result in suboptimal planning decisions. To help stakeholder transparency, it may be beneficial to develop capacity plans with and without policy goals that use otherwise consistent methodologies to better characterize the risk in the decision-making process.

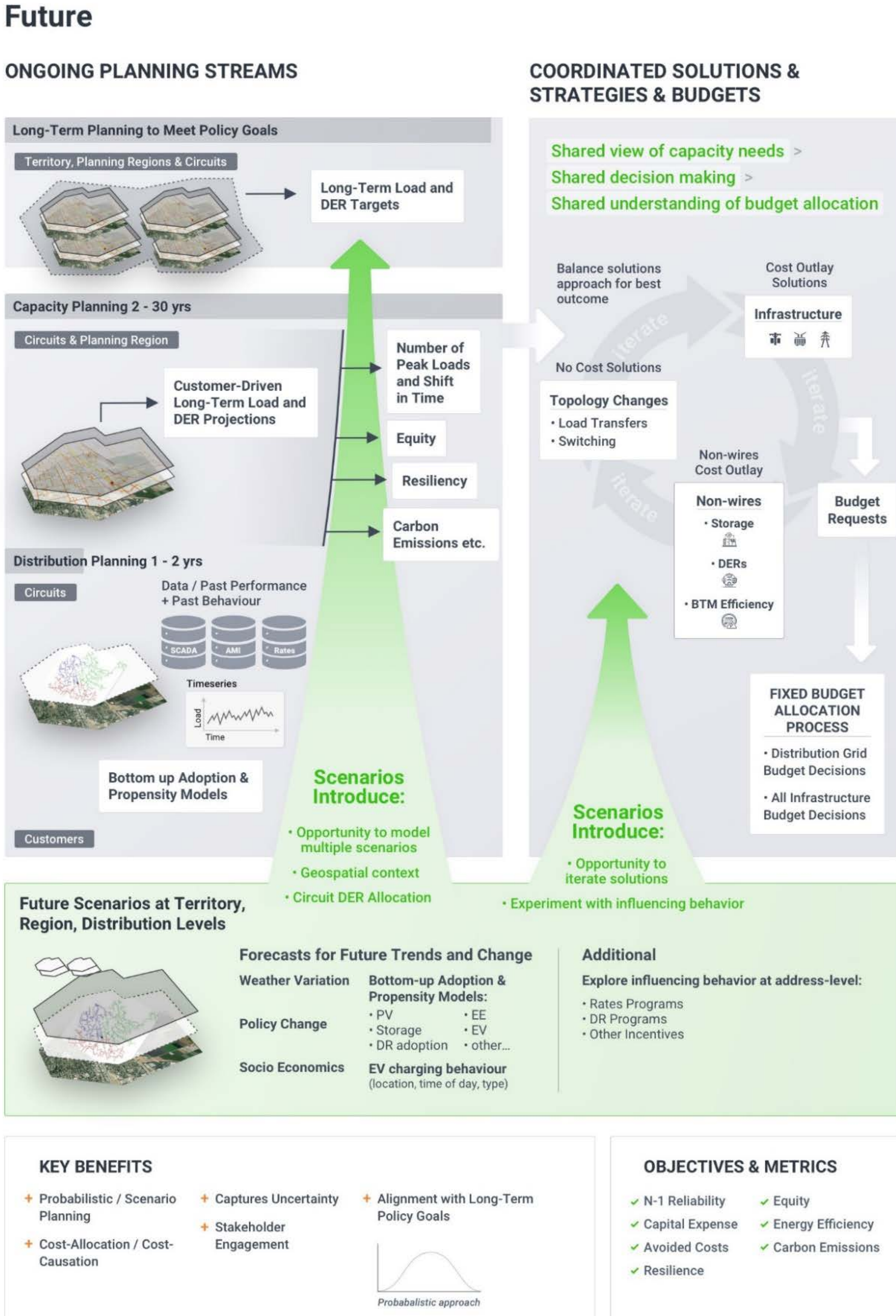

Figure 2. Future distribution capacity planning framework with scenarios and probabilistic bottom-up load and DER adoption models, as well as multiple objectives and metrics driving the evaluation of distribution capacity solutions

Data Integration and Scenario Planning

The second opportunity to improve distribution capacity planning is the development of integrated data stores. These data stores should ensure consistency between operational and planning data for transmission and distribution operators; however, there are data quality challenges in identifying bad data and developing cost-effective data cleaning strategies. AMI is rarely leveraged in the distribution capacity planning process. Using multiple demand measurements from the grid edge to the feeder and substation can increase the granularity of the information being used to characterize the baseline load and to look ahead to predict future load and technology adoption models. For example, AMI could be used to develop 8,760 customer class profiles or to create temperature-driven customer load models based on historical behavior.

Granular grid-edge data can be used to improve circuit forecasting and validate circuit modeling. One way to do this is by "cleaning"[20] SCADA to match downstream AMI readings and to inform distribution models. Doing so would increase the confidence of the capacity planning team in the connectivity models used by utilities. In addition, load and DER disaggregation methods can be applied to enable the distinction between native load and demand modifier technologies (e.g., BTM solar and/or storage, and EVs). This ability to unmask native load is already a critical requirement for distribution and transmission operations groups in areas of the country with large DER penetration, and it will become increasingly important in distribution planning data needs. With effective integration of AMI and SCADA, distribution system reconfiguration, and DER output, an integrated data store could more accurately determine circuit peak loading and the correct allocation of new load and DERs.

Integrated data stores provide a critical foundation for data-driven analytics such as time-series analysis, what-if scenario, and probabilistic analysis. Integrated data stores could include granular customer consumption, costs, and grid measurements. These data would allow a shift toward an integrated planning process with internal consistency for determining grid infrastructure needs. Moreover, the availability of data stores will be critical to unlocking the application of more statistical approaches by translating data inputs into machine-readable formats. This will enable new tools that allow planners to test different scenarios accounting for different possible futures. Given the uncertainty inherent in all DER forecasting approaches, this probabilistic bottom-up forecast of load and DER will enrich the evaluation of distribution investments and introduce the possibility of risk-based planning and decision-making at the distribution level. Planning analysis balancing risk and cost-effectiveness will depend on larger and high-quality data sets with metrics measuring input uncertainty. The objectives and metrics for evaluation will be expanded in the following section.

Distribution Planning Objectives and Metrics

The final opportunity to improve distribution capacity planning we identify in this white paper is the development of standardized objective metrics and frameworks that reflect advanced distribution planning objectives and allow stakeholder engagement.

[20] Distribution networks are dynamic. Large loads and DER can become disconnected, and switching operations can change the customers that are connected to a substation transformer. For planning purposes, SCADA may need to be "cleaned" to ensure SCADA measurements are aligned with distribution network modeling.

Advanced capacity planning should continue to prioritize decision-making that minimizes utility capital and operational costs while maintaining N-1 circuit-level reliability. However, asset investment decisions may also be impacted by other objectives, such as:

- Hosting capacity
- Cost of service and avoided costs
- Reliability and resiliency
- Equity and energy justice
- Energy efficiency
- Carbon emissions.

Objective metrics and decision-making frameworks to weigh the importance of each metric should be clearly defined to align corporate utility goals with external stakeholders and regulatory bodies. For example, capacity investments in DER and conductor upgrades can have varying impacts on recovery efforts following storms, customer interconnection opportunities, line losses and feeder-avoided costs, equity, and avoided local and regional emissions. These other objectives are currently not being considered in the capacity planning process. Such new objectives could be reflected in a series of avoided costs and reliability and resilience metrics that could be used along with the current investment and deferral needs practices to improve the overall distribution capacity planning process. Utility Highlight 1 discusses ongoing work by Pepco Holdings to develop a holistic set of technology-agnostic metrics. Utility Highlight 2 discusses Duquesne Light Company's efforts to integrate equity and resilience into its distribution planning processes.

Utility Highlight 1. Pepco Holdings—Ongoing Development of Holistic and Technology-Agnostic Metrics

Traditional planning and infrastructure investments are generally aligned with a business objective that can be measured. Examples include system performance or reliability metrics—such as Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI), or System Average Interruption Frequency Index (SAIFI)—or capacity expansion and load forecast variance measuring forecasted and actual peak demands relative to capacity limits. The solutions are mature and confidently support improving those metrics, and they are generally compared to select the lowest-cost solution that has the greatest impact on the metrics. Pepco is working to develop a holistic and technology-agnostic set of metrics that can be applied with the same confidence to traditional utility investments and non-wires solutions. The goal is to level the playing field and appreciate the full spectrum of benefits and risks that new non-wires solutions proposals bring for customers. As utilities move toward using non-wires solutions, the metrics may expand to include energy market values as well as carbon reduction and new business opportunities.

Utility Highlight 2. Duquesne Light Company—Integrating Equity and Resilience into Distribution Planning

> As utilities invest in electric grid upgrades to improve resiliency and reliability, it is crucial to ensure investment is executed equitably, so that all communities have equal access to reliable, clean, and affordable electric power. Power outages disproportionately affect underserved and disadvantaged communities due to higher rates of health issues, lower access to food, and lack of other essential services. There is also a need to focus investment on underserved communities because low-income households have, on average, an energy burden three times that of non-low-income households. There is a critical need to combine utility planning in a way that accounts for the resilience goals of communities, the opportunities and constraints of utilities, and emerging technologies. Duquesne Light Company is beginning to use software tools to integrate socioeconomic and neighborhood factors into system planning and asset strategy practices so that it can ensure investments are made where they are most needed from both grid and societal perspectives.

Standardized objective metrics and frameworks would allow distribution planning engineers to make decisions and engage stakeholders with a consistent, defendable, and repeatable process. Wherever possible, metrics should be supported by historical and model-driven key performance indicators. They could include past forecasting accuracy to measure the certainty of future load growth or past DER performance in helping reduce peak load. However, care should be taken when building penalties and rewards around key performance indicator performance, as doing so can lead to unintended consequences.

Lack of Distribution Planning Guide

Unlike the transmission system that has the North American Electric Reliability Corporation's Transmission System Planning Performance Requirements,[21] there is currently no federal, state, or local guidance on conducting DSP or defining the distribution system requirements and performance metrics. The industry would benefit from having a distribution planning guide that could serve as a reference and provide for best practices on conducting distribution planning activities and creating evaluation frameworks, without prescribing an "one-size fits all" approach to distribution planning.

[21] Transmission Planning Reliability Standard TPL-001-5, 85 Fed. Reg. 8155 (Feb. 13, 2020). Transmission Planning Reliability Standard TPL-001-5. https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

Decision Support Methods

As utilities develop long-term spatial forecasting capabilities, integrated data stores, and standardized objective metrics, engineers will see an exponential rise in the number of scenarios they need to analyze and a commensurate increase in discrete decision points. Decision support tools could help utilities choose between switching options, traditional wire solutions, and the many NWA configurations available to address capacity constraints. Forward-looking decision support methods could be developed that align with the forward-looking nature of IRP and IGP planning frameworks. For example, an IGP with decision support tools could proactively assess how long-term distribution capacity costs would change with and without managed EV charging, DERs, and other load management options. Such forward-looking analytical capability could help utilities both (1) address cost causation questions caused by DERs and electrification and (2) better holistically plan for DER interconnection and capacity expansion needs.

Forward-looking decision support tools could be complementary to NWA frameworks. While NWA frameworks are executed with relatively short lead times in response to capacity constraints, a forward-looking decision support tool could help utilities develop NWA strategies over longer time horizons. Forward-looking distribution capacity decision support tools could draw on many of the best practices of bulk grid planning.

Bulk grid planners have an array of production cost modeling and generation capacity expansion models to inform IRP proceedings and proactively assess future scenarios. The bulk system also relies on the concept of resource adequacy, which is used to assess whether a power system has an appropriate set of resources to maintain continuous service to demand with a desired level of reliability. To inform the uncertainty discussion, resource adequacy studies rely on adequacy assessment metrics and minimum criteria for low-carbon systems in the face of a changing climate.[22] The goals of such metrics are to provide a comprehensive picture of system risk to planners, regulators, and policymakers, and to help establish minimum adequacy criteria that reflect the costs and benefits of avoiding unserved energy. Distribution capacity planning could incorporate similar risk-based planning methods, adapted to the needs of the distribution systems, to better capture uncertainty and scenario-based modeling to evaluate capacity expansion needs and solutions. These methods add complexity to the distribution planning process, and it will be important to understand the added benefit.

Distribution capacity planning decision methods are needed to simulate future scenarios and proactively assess potential strategies. These decision support frameworks should have several requirements.

1. **Interoperability Between Data and Software Tools:** Common data stores and their integration with existing distribution analytical tools (e.g., power flow, spatial load forecasting, and rate databases) represent a growing requirement for utilities to make more integrated decisions across departments. For example, new distribution operations software and hardware solutions such as DERMS, Volt/VAR (volt-amps reactive) optimization, flexible interconnection methods, smart load panels, and home energy

[22] See Electric Power Research Institute (EPRI), *Resource Adequacy for a Decarbonized Future: A Summary of Existing and Proposed Resource Adequacy Metrics*, April 2022. https://www.epri.com/research/products/000000003002023230.

management systems will ultimately affect the assumptions for distribution planning, and new decision support methods would need to model the effect of such real-time controls in capacity planning. Some utilities may apply these operational tools as NWAs. Distribution capacity planning methods could provide locational capacity value information to the rate design process, which could be used to better capture cost shifts caused by the difference between the value of DERs and DER tariffs. They could also inform the price responsiveness of customers to new rate structures in the modeling assumptions and uncertainty of load forecasts.

2. **Probabilistic and Scenario-Based Planning Tools:** New decision support tools should support scenario and probability-based uncertainty quantification. The nature of the risk analysis should be flexible and depend on utility needs with defined industry standard risk tolerances. Industry would benefit from expanded scenario analysis based on the uncertainty in DER and EV growth. Probabilistic-based uncertainty quantification requires extensive designation of random variables. This process is overly burdensome for many utilities today, but it will become increasingly necessary as the amounts of DER, EV, electrification, and other prosumer technologies grows. If probabilistic methods are adopted, distribution resource adequacy metrics will become especially important. It would be exceedingly risky to plan system infrastructure for average conditions and expensive to plan for the worst-case scenario.
3. **Enable Stakeholder Engagement:** Decision support methods should provide common metrics to help engineers make consistent, defendable, and repeatable planning decisions. At a minimum, these metrics would include cost and reliability. With stakeholder and regulator input, they may also include cost of service, resilience, energy efficiency, equity, emissions, and hosting capacity. A utility can use a framework weighing the relative value of these metrics developed through stakeholder collaboration to make transparent decisions.

Conclusion

Excellent research and development are being conducted to improve operations (e.g., DERMS) and short-term planning (e.g., hosting capacity) for EVs and DERs. However, DER, EVs, EVSE, and other electrification technologies will continue to challenge long-term distribution planners. These challenges also come with opportunities. Improved load and DER forecasting, data integration and storage, metrics and key performance indicators, and decision support tools can help utilities make capacity investment decisions while supporting all stakeholder interests.