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Integrated Resilient Distribution Planning

May 2022

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U.S. DEPARTMENT OF ENERGY

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Acronyms and Abbreviations

CAIDI	Customer Average Interruption Duration Index
CPUC	California Public Utility Commission
DDIF	Distribution Investment Deferral Framework
DER	Distributed Energy Resources
DOE	Department of Energy
DSPx	Distribution System Platform
GCM	Global Climate Model
GIS	Geographic Information Systems
GNA	Grid Needs Assessment
HFTD	High Fire-Threat District
IDP	Integrated Distribution System Planning
IOU	Investor-Owned Utility
IPCC	International Panel on Climate Change
IRDD	Integrated Resilient Distribution Planning
IRD	Integrated Resource Planning
MAIFI	Momentary Average Interruption Frequency Index
MIR	Microgrid Incentive Program
PSPS	Public Safety Power Shutoff
RWG	Resilience Working Group
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
VSE	Value-Spend Efficiency

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1.0 Introduction

The federal government, states, local communities and utilities recognize the need to enhance the resilience of the nation's electric grid to reduce the impact from major events. These types of events include natural disasters and cybersecurity incidents that impact quality of life, economic activity, and national security. Resilience events occurring within electric distribution grids involve similar types of infrastructure failures (e.g., wires down, poles broken, transformers failed, fuses blown, etc.) witnessed in reliability events, but at a greater scale involving a more complex and widespread set of operations for restoring the electric grid.

While distribution reliability assessments have traditionally been performed annually, over the past decade, states and utilities have increasingly sought to enhance distribution resilience as well. Resilience planning is becoming a major consideration within the context of comprehensive system planning[1] which includes integrated distribution system planning (IDP), integrated resource planning (IRP), and transmission planning. The Integrated Resilient Distribution Planning (IRDP) process described in this paper provides an approach for incorporating resilience into distribution system plans; a necessary step towards incorporating resilience into larger, comprehensive plans.

The IRDP process is designed to employ both near-term and long-term grid assessments to facilitate effective decision-making regarding distribution grid needs and expenditures. The goal of the IRDP is to demonstrate the interconnected relationships between several objectives, which will then lead to more effective grid investments. Unlike traditional siloed distribution planning, the IRDP process includes a number of interrelated activities that are driven by planning objectives based on customer needs and public policies. Some of these objectives include decarbonization, equity, electrification, the integration and utilization of distributed energy resources[2] (DER), and use of non-wires alternatives to optimize infrastructure investments.

Additionally, planning must address engineering criteria with a focus on safety and reliability. These planning criteria define the minimum performance requirements for the distribution system and inform the engineering analysis, grid needs, and solution identification. Prioritization of investments and implementation roadmaps are also shaped by policy and stakeholder priorities within given financial constraints. Ultimately, the performance of these implementation plans should be assessed against the planning criteria metrics that together provide feedback into the next planning cycle. This process is summarized in Figure 1.

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[1] See NARUC-NASEO Task Force on Comprehensive Electricity Planning. https://www.naruc.org/taskforce/background/

[2] DERs are resources sited close to customers that can provide all or some of their electric power needs or can be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the grid. The resources are small in scale, connected to the distribution system, and close to load. Examples of different DER types include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), grid-interactive buildings and other flexible loads, electric vehicles (EVs), microgrids, and energy efficiency (EE).

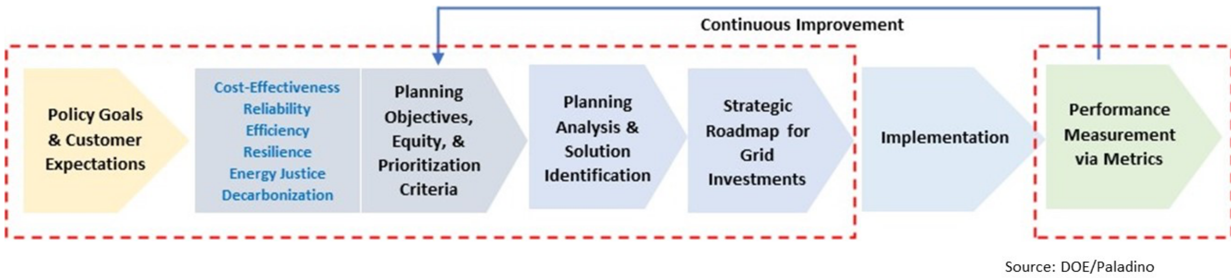


Figure 1. Planning Lifecycle

This paper is intended to provide an update to the IRDP discussion in DSPx Volume 4 Guidebook[3] (DSPx Guidebook) and the earlier Integrated Distribution Planning for Minnesota.[4] Specifically, this paper provides a discussion of the overall integrated process elements in summary along with a deeper view of the current and emerging best practices for resilience planning as well as stakeholder informed prioritization of investments. This paper also draws on the prior Pacific Northwest National Laboratory work on resilience engineering analysis, resilience solution portfolio development, and energy equity and justice work.[5, 6,7]

[3] P. De Martini, J. Taft, et al., Modern Distribution Grid, Volume IV: Strategy and Implementation Planning Guidebook v1.0, DOE-OE, 2020. Available at: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf
[4] P. De Martini, Integrated Distribution Planning, ICF-DOE, 2016
[5] P. De Martini and J. Taft, Distribution Resilience and Reliability Planning, Pacific Northwest National Laboratory, January, 2022. Available at: https://gridarchitecture.pnnl.gov/media/advanced/Resillience_Solution_Analysis_paper.pdf
[6] PNNL, What is Energy Equity? https://www.pnnl.gov/projects/energy-equity
[7] Tarekegne B,W., B. Pennell, D.C. Preziuso, and R.S. O'Neil. Review of Energy Equity Metrics, PNNL 2021. https://www.pnnl.gov/publications/review-energy-equity-metrics

2.0 Integrated Resilient Distribution Planning

The goal of the IRDP process is to demonstrate the interconnected relationships between several planning objectives, which will then lead to more effective grid investments. At the highest level, the IRDP process includes these basic elements:

- Identifying near-term and longer-term grid planning objectives (including traditional and emerging objectives) and criteria (including minimum reliability performance requirements, code and regulatory requirements), which together drive the planning process as well as;
- Performing best-practice engineering analysis for safety, resilience and reliability, and DER integration and utilization,
- Determining incremental grid needs, system changes, or changes to existing plans; and
- Identifying and evaluating potential solutions (e.g., those associated with capital expenditures, operations and maintenance expenses, and customer and third-party solutions) using risk-based engineering-economic methods.

A stepwise view of an integrated planning process is provided in Figure 2 below. The Steps 1A and B boxes represent the higher-level planning inputs and assumptions along with the formulation of planning priorities and criteria (green). These efforts may involve community or state-level risk assessments that inform policies and planning priorities. The Step 2 box (grey) represents the utility specific climate threat risk and system resource and load forecasts and scenarios. The Step 3 box (orange) highlights the interactive relationships between resource, transmission, and distribution system planning. The Step 4 boxes (yellow) depict the set of distribution level engineering analyses. Distribution plan development activities (blue) are depicted in the Step 5 box. Finally, regulatory approval and ex-post evaluation of implementation results is illustrated in Step 6 (darker blue). The figure also depicts key interaction with stakeholders (green boxes) in the planning cycle.

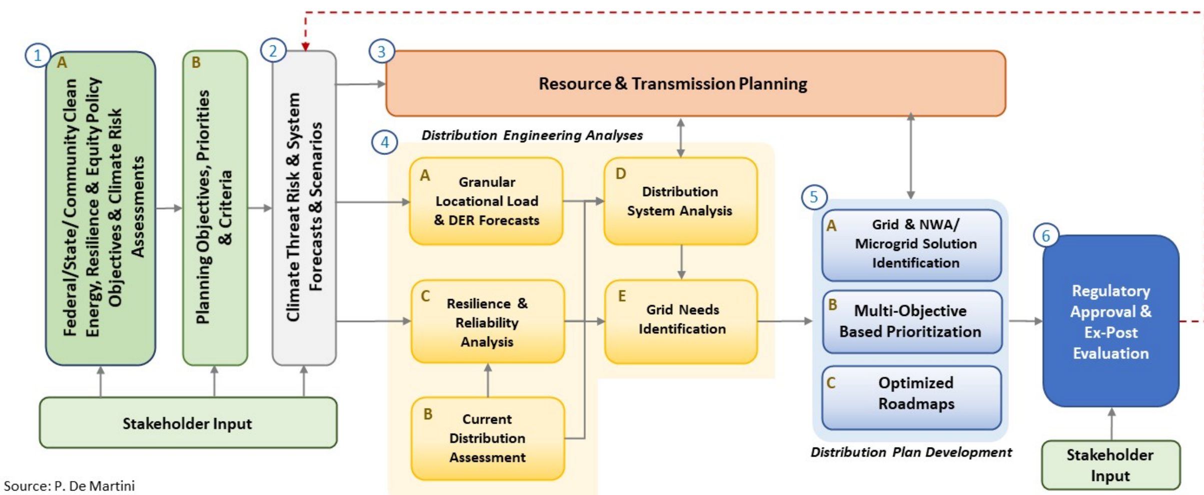
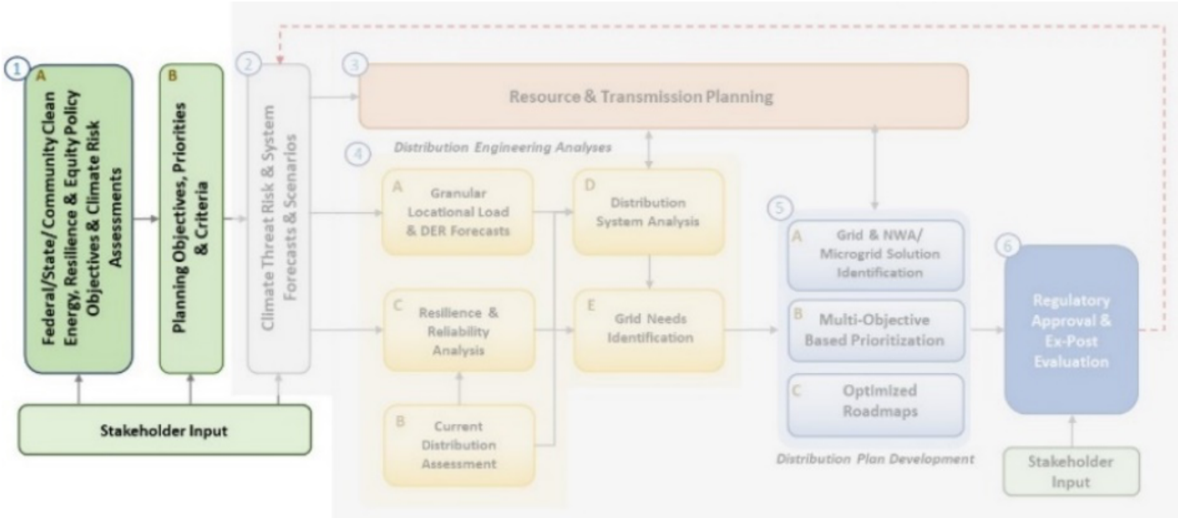


Figure 2. Integrated Resilient Distribution Planning Process

This paper describes these process elements and interrelationships in more detail in the numbered sequence consistent with the Figure 2. This sequence is generally reflective of emerging best practices for the industry and is performed to determine both near-term (0-3 year) and long-term (5-15 year) investment strategies.

2.1 Step 1. Government & Community Objectives, Priorities, & Criteria



2.1.1 Objectives, Priorities, & Criteria

As a starting point, integrated resilient distribution planning must consider a wide range of federal, state, local, and tribal government goals and policies. Regulatory jurisdictions or public/community governing boards translate these policies into a specific set of planning-related objectives and criteria. As part of this process it is essential to acknowledge and incorporate communities and vulnerable populations negatively impacted by environmental, social, and economic inequities. Recent equity and justice education now recognizes communities not previously acknowledge or included in the process. There is increased intentionality to partner with these individuals and communities for effective engagement and collaboration that leads to desired outcomes from the planning effort.

The resulting objectives are intended to address decarbonization, social equity, changing customer expectations, and service quality requirements. These objectives may involve improving existing capabilities or adding new ones, often related to enabling distributed resource adoption, electrification, and improvements in resilience and reliability, in addition to statutory operational compliance.

2.1.1.1 Objectives & Priorities

An objective is a desired outcome with an associated timing and/or performance criteria.

For planning purposes, an objective is generically defined as a desired outcome with an associated timing and/or performance criteria. Objectives may include a) specific customer, policy, and/or business outcomes and b) associated timing and/or performance requirements. Objectives inform what is needed by when and guide the subsequent steps in the process. This is illustrated with Vermont's overall policy drivers that included clear objectives and timelines with grid planning implications, shown in Figure 3.[8]

[8] Office of Electricity Delivery and Energy Reliability, "Strategic Planning for Grid Modernization: DSPx Phase 2" PowerPoint presentation provided at New England Conference of Public Utility Commissioners (NECPUC) Vermont Sessions, October 9, 2018, accessed June 2020, http://necpuc.org/.

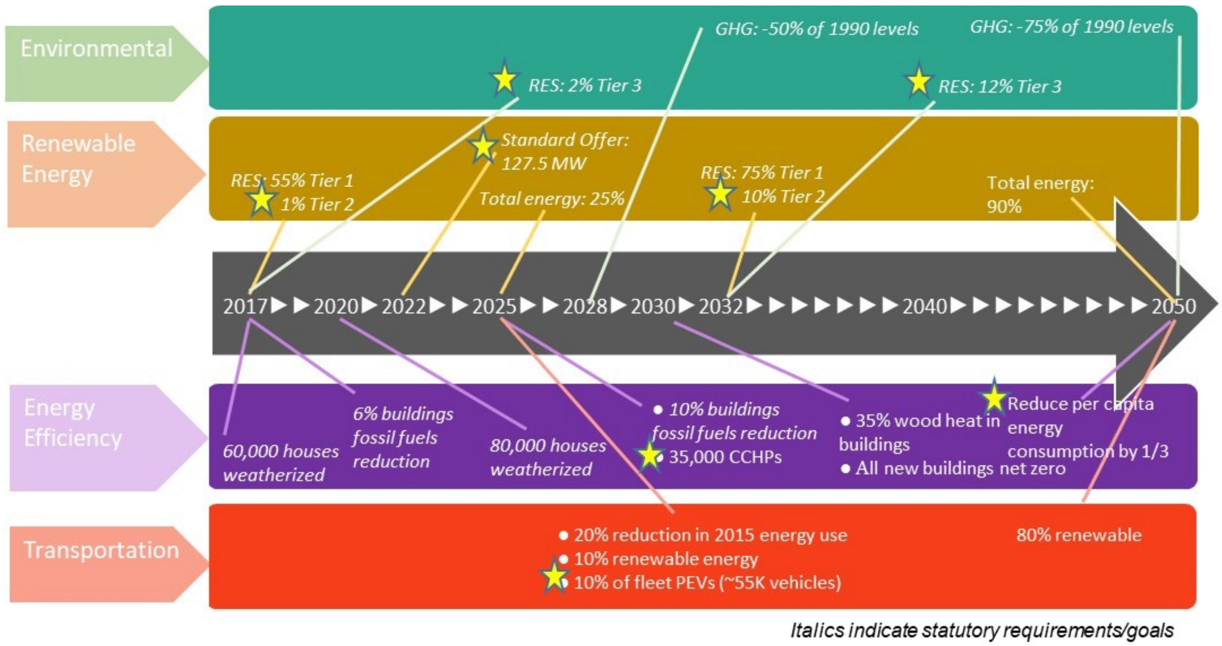


Figure 3. Vermont Policies with Grid Planning Implications

Given the increasing range of objectives to consider, there is a need to strategically prioritize and contextualize the objectives to support planning development with stakeholder involvement, recognizing that tradeoffs may occur with prioritizations, and unintended consequences should be considered. These objectives are gathered in Step 1 with key stakeholder involvement, It is also preferred that the regulatory commission provide the forum to identify the prioritization through engagement of relevant stakeholders, as discussed below, to ensure alignment with policy intent including equity goals. Prioritization can include differentiation among competing policies as well as equity priorities associated with certain populations.[9] Prioritization at this step involves developing the prioritization criteria and/or weighting factors to be applied later in Step 5.

2.1.1.2 Climate Risk Assessment

A key consideration for electric system planning is assessing climate change impacts. The starting point is often a state and or local government[10] climate threat-risk assessment, such as that by Michigan's 2019 Hazards Report illustrated in **Error! Reference source not found.** Also, California's Planning and Investing for a Resilient California: A Guidebook for State Agencies is an example guide for development of these threat assessments.[11]

[9] California Executive Order B-30-15, Resiliency Guidebook-Vulnerable Populations.2018. Available at: https://opr.ca.gov/docs/20180312-Vulnerable_Communities_Descriptions.pdf
[10] Resilient Cities Network https://resilientcitiesnetwork.org/
[11] Available at: https://opr.ca.gov/docs/20180313-Building_a_Resilient_CA.pdf

Quantitative Summary by Region
Source: NCEI Storm Events online database* (1996-2017)

Geographic Division→	Upper Peninsula: Average annual events	Upper Peninsula: Average annual deaths	Upper Peninsula: Average annual injuries	Upper Peninsula: Average annual property and crop damage	Northern Lower Peninsula: Average annual events	Northern Lower Peninsula: Average annual deaths	Northern Lower Peninsula: Average annual injuries	Northern Lower Peninsula: Average annual property and crop damage
Hail	2.2	0	0	$3,302,677	1.3	0	> 0	$2,012,844
Lightning	0.1	0.1	0.2	$24,600	0.1	0.3	1.3	$49,337
Ice and sleet storms	0.2	0	0	$14,063	0.1	0	0	$83,205
Snowstorms	8.8	0.1	0.1	$70,900	3.7	0	0	$1,243,754
Severe winds	3.0	0.1	0.1	$1,064,335	1.9	0.2	2.6	$4,647,190
Tornadoes	0.1	0	0	$351,568	0.1	> 0	0.2	$348,474
Extreme heat	> 0	0	0	$0	> 0	0	0	$0
Extreme cold	1.4	> 0	0	$0	0.1	0	0	$3,492,242
Fog	0.2	0	0	$0	> 0	0	0	$0
Flooding	0.8	> 0	0	$2,374,256	0.3	0	0	$2,591,244
Shoreline hazards	1.1	0.5	0	$9,469	> 0	0.2	> 0	$0
Drought*	> 0	0	0	$0	> 0	0	0	$0
Wildfires	> 0	0	0.2	$849,201	> 0	0	0	$109,689

Source: 2019 Michigan Hazard Mitigation Plan

Figure 4. 2019 Michigan Risk-Threat Summary Table Excerpt

The United Nations International Panel on Climate Change (IPCC) collects and freely distributes multiple “Global Climate Models” or GCMs. This information supports the identification of climate trends to inform public policy as well as supports the development of planning objectives. For example, Figure 5 shows Con Edison’s projections of sea rise through 2100[12] that has significant consequences for the community as well as for the electric system.

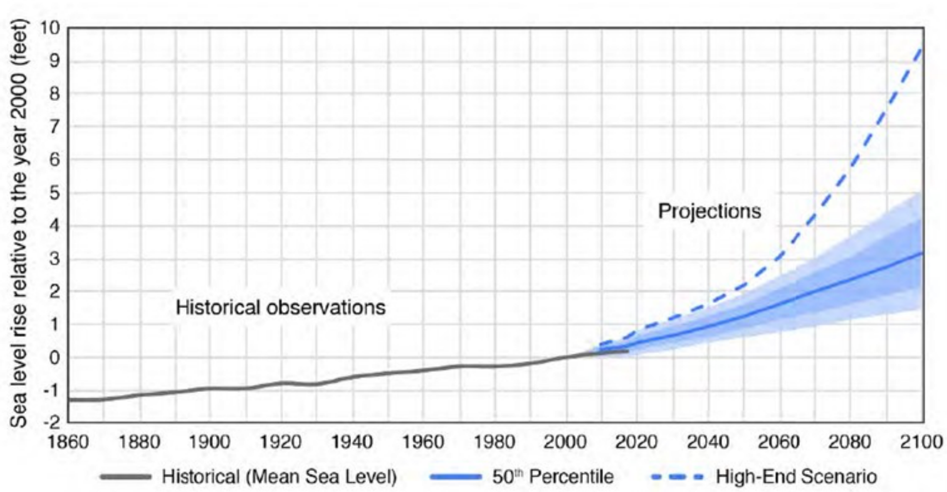


Figure 5. ConEdison Climate Threat Risk Projection Due to Sea Level Rise

[12] ConEdison, Climate Change Vulnerability Study, 2020. Available at: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-resilience-adaptation-2020.pdf

These types of state, county and city hazard risk assessments provide the scope and societal impacts to inform resilience and equity policies that ultimately define electric system planning objectives.

2.1.1.3 Criteria

Planning criteria are derived from the objectives and priorities as discussed above. Planning criteria are system design and operating parameters established to ensure safe and reliable grid operation under normal, transient, and contingency conditions, and they must be considered in planning processes. Such criteria often define requirements for the management of current thermal limits, voltage, and frequency, as well as service quality to customers.[13] They are often expressed in national, state, and regulatory standards for service quality and reliability that may also be codified in regulation. Planning criteria are also informed by decarbonization, equity, and resilience objectives. These objectives should be translated into planning and operating criteria. Taken as a whole, these criteria define acceptable and unacceptable levels of distribution system performance, utility reporting requirements, and applicable incentives and/or penalties for utility performance.[14]

2.1.2 Stakeholder Engagement

A critical dimension for Step 1 and Step 2, in particular, as well as throughout the planning cycle is effective stakeholder engagement. The decision-making processes of regulatory commissions and utilities are becoming challenged with increasingly complex, strategic, and potentially precedent-setting issues that have significant consequences for an expanding set of constituents. The scope of planning now involves addressing climate change threats, decarbonization goals, changing consumer expectations, and equity considerations which are constantly evolving. Tackling this expanding scope will require meaningful stakeholder engagement to shape the objectives, criteria, and priorities as inputs into the planning process. As such, an essential dimension to comprehensive system planning, especially with IRDP, is effective and equitable stakeholder engagement.[15]

Goal is meaningful stakeholder engagement to shape the planning objectives, criteria and priorities for the planning process.

Such an engagement may create a shared consensus among stakeholders of the ultimate strategies and implementation plans for grid transformation needed to meet resilience, decarbonization, and equity objectives. As shown in Figure 6, this fundamentally involves stakeholder engagement in two aspects: 1) policy formulation identifying societal objectives and priorities (e.g., priotitization criteria/scoring frameworks), and 2) development of grid planning objectives and performance criteria.

[13] An example of a high-level planning criterion that would then guide more detailed engineering requirements may be articulated as follows: “neither end-use customer load nor interconnected customer generation shall cause any power quality-related issues to the utility grid or any utility end-use customer.”
[14] An example of such a standard may be found in: Michigan Department of Public Labor and Economic Growth, Public Service Commission, Service Quality and Reliability Standards for Electric Distribution Systems, https://www.michigan.gov/documents/mpsc/Service_Quality_Standards_672262_7.pdf.
[15] P. De Martini, C. Brouillard, M. Robison, and A. Howley, The Rising Value of Stakeholder Engagement in Today’s High-Stakes Power Landscape, ICF, 2016. Available at: https://www.icf.com/-/media/files/icf/white-paper/2016/energy-regulation-stakeholder-engagement.pdf

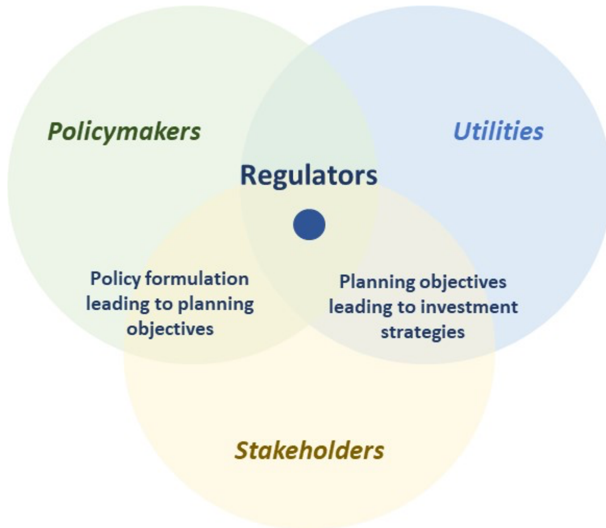


Figure 6. Stakeholder Engagement Model

The focus of stakeholder engagement over the past decade has primarily involved a discussion of the integration and utilization of DER. This has historically largely drawn consumer, environmental, and DER advocates into planning discussions. However, resilience considerations are now expanding the set of interested constituents to include equity advocates, utility customers, community groups, and local governments. For example, Section 40108 of the Infrastructure Investment and Jobs Act of 2021 (Public Law 117-58) requires that states undertake a threat-based risk assessment of energy infrastructure and identify mitigation strategies.[16] A summary of the Section 40108 requirements is provided in the Appendix.

As shown in Figure 7, the scope and scale of identified threat-risks often shapes who will likely be involved in process. This figure illustrates the types of stakeholders that should be engaged based on whether the threat-risk is localized (e.g., city/county), larger major local risk (e.g., multi-county), or regional (multi-state scale).

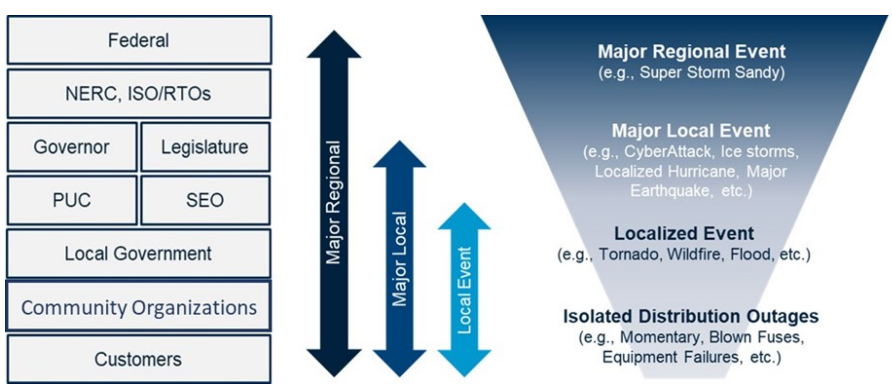


Figure 7. Stakeholder Engagement in Resilience Planning

Stakeholders are increasingly providing necessary input into prioritization of threat-risks, identifying critical and essential facilities, and vulnerable and access-needs populations. This input is foundational to establishing planning objectives and criteria for the engineering analyses

[16] The Infrastructure Investment and Jobs Act (Pub. L. 117-58) is available at https://www.congress.gov/bill/117th-congress/house-bill/3684/text

that follow, as well as in shaping ultimately, the resilience and associated grid modernization strategy of IRDPs. Many non-energy impacts focus on direct and measurable financial impacts on ratepayers[17], where the full scope extends past this population and economy; a more inclusive stakeholder group better defines the program impacts on disadvantaged communities and how to minimize those impacts. Figure 8 presents a prioritization of customer types developed by the Hawaii Resilience Working Group through a stakeholder-led process involving federal, state, and local government, as well as critical infrastructure representatives and consumer advocates.[18] This report was reviewed for input by Hawaiian Electric's Stakeholder Council which includes a wider set of local community advocates from each island they serve. However, it is important to effectively engage vulnerable and disadvantaged communities earlier in the planning process along with relevant federal, state, and local governments, agencies, and industries.

Source: HECO Resilience Working Group Report, 2020

Figure 8. Customer Prioritization of the Hawaii Resilience Working Group

The preparation of the implementation plan for California's Microgrid Incentive Program included extensive stakeholder engagement with a particular focus on vulnerable and disadvantaged communities and populations.[19] A key aspect of these discussions was on the development of a prioritization model for the purpose of distinguishing various proposed community microgrid projects for limited program funding allocation. Figure 9 below is an initial draft of a prioritization framework used to facilitate discussion among stakeholders. While this framework is specific to this program, the figure illustrates a method for identifying priorities, criteria, and scoring based on priorities aligned to the enabling legislation. This method can also be used to enable thoughtful stakeholder input.

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17 National Association of Regulatory Utility Commissioners, 2021. "The Role of State Utility Regulators in a Just and Reasonable Energy Transition"

18 Hawaiian Electric Resilience Working Group Report, 2019. Available at: https://view.hawaiianelectric.com/jupiter-intelligence-special-report/page/1

19 https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/microgrid-incentive-program.page?WT.mc_id=Vanity_mipworkshops

Evaluation Category	Subcategory	Scoring Parameter/Criteria	Scoring Specification	Scoring Weight
Customer & Community Benefits	Low Income Customers	# CARE/FERA customers in CMG	# of customers or % population	50%
	Vulnerable Customers	# AFN/Medical Baseline/Life Support customers in CMG	# of customers or % population	
	Critical Facilities (CF)	Number of Critical Facilities in CMG	Each CF in CMG Each CF serving DVC	
	Community Services	# Community Services in CMG	Each facility	
Community Resilience Benefits	Vulnerable to Outages	HFTD/HFRA Prior PSPS Earthquake/flood-prone Lower Reliability	Hazard Exposure	30%
Community Environmental Benefits	Clean Energy	% Clean Energy Used	Installed renewable capacity (MW) divided by peak load	20%
	Fossil Fuel Displacement	# Critical Facilities in CMG	Each CF displacing fossil fuel BUG as primary back-up	

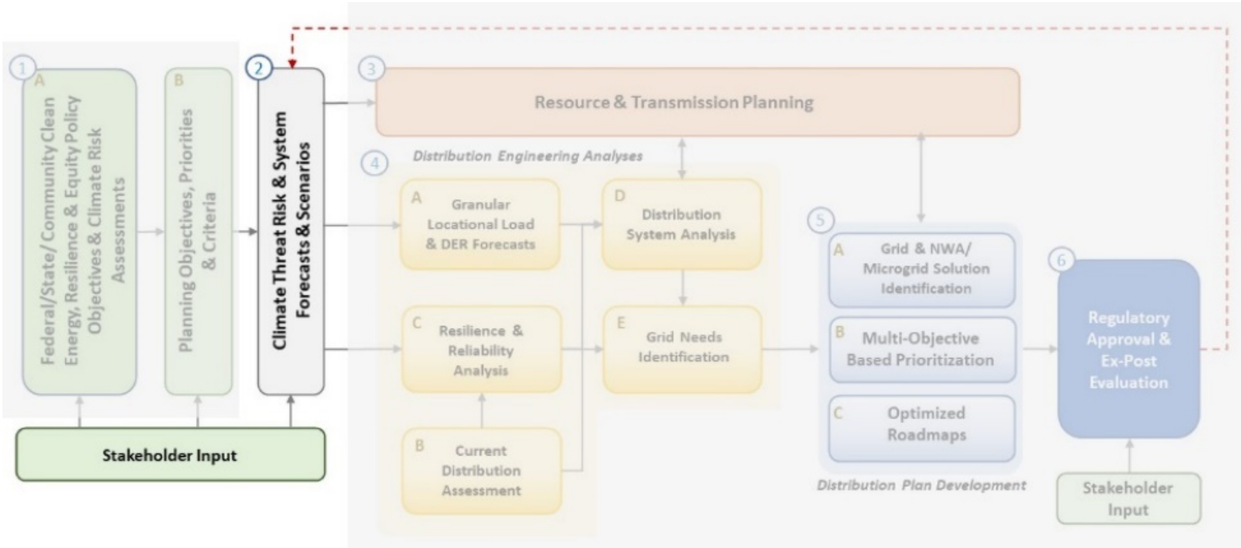
Source: CA IOUs Proposed Microgrid Incentive Plan based on Stakeholder Input , 2021

Figure 9. Draft Microgrid Incentive Plan Prioritized Scoring Framework Example

Stakeholder engagement today is a much more complex undertaking. This requires understanding the respective interests of a wider set of stakeholders and developing a process to engage these constituencies in defining planning objectives, priorities, and criteria for an integrated, resilient distribution planning process. This includes recognizing that some stakeholders are new to regulator-driven, utility planning processes and may have limited resources to engage effectively in them. Partnership programs are developing mentorship and technical assistance to community programs to assist in education in grid planning and to allow diverse access to a historically technocratic conversation[20]. The role of social justice in grid planning is complex and continually expanding.

[20] J. Eagles, "In Pursuit of Equitable Clean Energy: The Power of Coalitions for Utility Regulatory Transformation," Institute for Market Transformation, 30 March 2021. [Online]. Available: https://www.imt.org/in-pursuit-of-equitable-clean-energy-the-power-of-coalitions-for-utility-regulatory-transformation/. [Accessed 8 November 2021].

2.2 Step 2. Climate Threat-Risk and System Forecasts



The next step in an IRDP process is identifying relevant forecasts and scenarios for local weather changes, distributed resources, and load applicable to the specific distribution systems under review. These forecasts and scenarios are a particularly important area of interest for stakeholders as they are key inputs used in the engineering analysis step that follows. As illustrated in Figure 10 there are many potential forecasts and plans developed by other entities outside a utility that may need to inform a distribution plan. Also, these forecasts may or may not be consistent with regards to underlying assumptions about the rate of electrification, DER adoption, and climate change impacts. This requires a level of reconciliation of these starting system forecasts with the policy objectives to create reasonable consistency before initiating the distribution engineering analyses processes.

A comprehensive approach to planning inputs supports the identification of opportunities for multi-objective solutions.

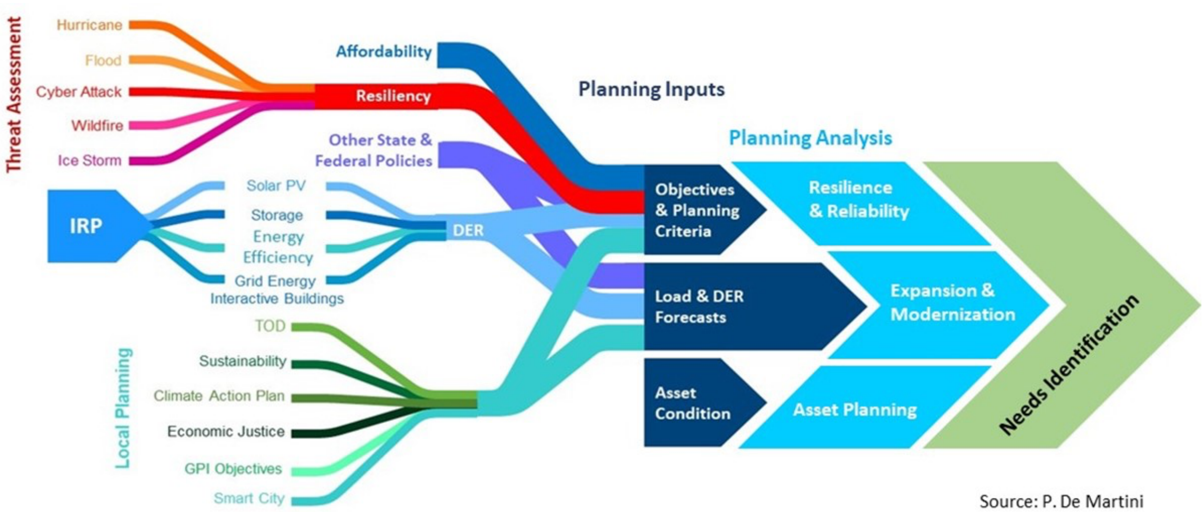


Figure 10. Distribution Resource Planning Inputs

The following discussion summarizes three important areas of input identified above in Figure 10: climate and security threat-risk assessment, resource and load forecasts from integrated resource planning (IRP), and local government plans. This comprehensive approach to planning inputs supports the identification of opportunities for multi-objective solutions.[21]

2.2.1.1 Threat-Based Risk Assessment

Increasingly, it is important to consider climate change impacts as part of an integrated distribution plan given the interrelationship with other forecasts and ultimately investment decisions. Therefore, an important step is to perform a threat assessment with key federal, state, and local stakeholders, as appropriate (discussed above in Step 2), to identify the potential threats and assess the risk of their probable impacts. As discussed in detail in NREL's Resilience Planning Guidebook, this involves a structured assessment of the threats together with their impacts and likelihoods, as well as the associated power sector vulnerabilities and their severities.[22] The following discussion focuses on threat-based risk assessment methodology addressing weather- and climate-related impacts. Although beyond the scope of this paper, it is equally important to assess and address cyber-threat risks, as well.

A threat-based risk assessment involves identifying and prioritizing the scale and scope of resilience threats based on assessing their impacts to specific components of the electricity delivery system and the communities it serves. Environmental and other threats are individually assessed and prioritized in terms of propensity to impact specific geographical areas. This includes identifying specific grid infrastructure that may be at risk and assessing its vulnerability and consequences if impacted.

However, it is necessary to translate the higher-level climate forecasts into more granular assessments for a utility's system. This requires converting climate data into local weather information. Changes in local weather is what policymakers and planners need to assess to determine distribution system risks. As a result, climate forecasts are just often the starting point. Climate is a description of a long-run average over a large area and the weather is the realization of climate in a small geographic and time scale. A complex, computing intensive effort called "downscaling" is required to transform low-resolution environmental information from large-scale GCMs into high-resolution spatial and temporal scales. This process is necessary in order to model and probabilistically predict hyper-local impacts of extreme weather. Downscaling can refine the "coarse" resolutions of climate-model data to much more granular scales—from 30 km to as fine as one meter (Figure 11). This capability is critically important for resiliency planning and risk management in use cases across the economy.[23,24]

Changes in local weather is what policymakers and planners need to assess distribution risks.

[21] Grid planning processes will need to address several objectives simultaneously, for example, those related to reliability, resilience, efficiency, decarbonization, equity, and cost-effectiveness. The ability to normalize and prioritize potential solutions within a multi-objective domain is an emerging challenge.

[22] National Renewable Energy Laboratory, Power Sector Resilience Planning Guidebook, Sherry Stout, et al. (2019), accessed June 2020, https://www.nrel.gov/docs/fy19osti/73489.pdf.

[23] R. Vaughn, Granularity Matters, Jupiter Intelligence, 2021. Available at: https://medium.com/jupiterintel/granularity-matters-2d3c22d6568c

[24] Jupiter Intelligence, The Right Approaches to Climate Model Downscaling, 2021. Available at: https://jupiterintel.com/wp-content/uploads/2021/06/Jupiter-Brief-Approaches-to-Downscaling.pdf

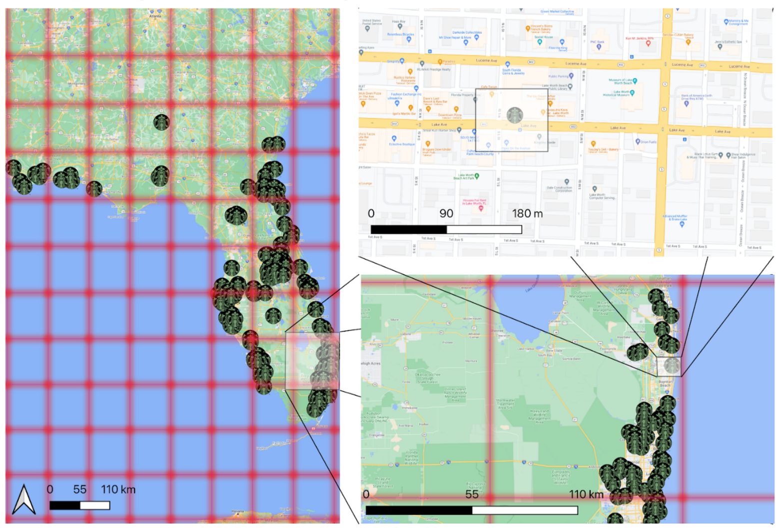


Figure 11. Downscale Threat-Risk Assessment

This type of climate risk data will help communities and utilities to prioritize geographic locations and related critical facilities and customers that are most at risk. The effort involves stakeholder-driven threat identification and prioritization, combined with customer segmentation and prioritization, and is a key input into the resilience planning process. An example of this approach is provided within the Hawaiian Electric Resilience Working Group (RWG) report[25] which includes their assessment and prioritization of resilience threats from natural causes, man-made physical attacks, and cybersecurity attacks shown in Figure 12.

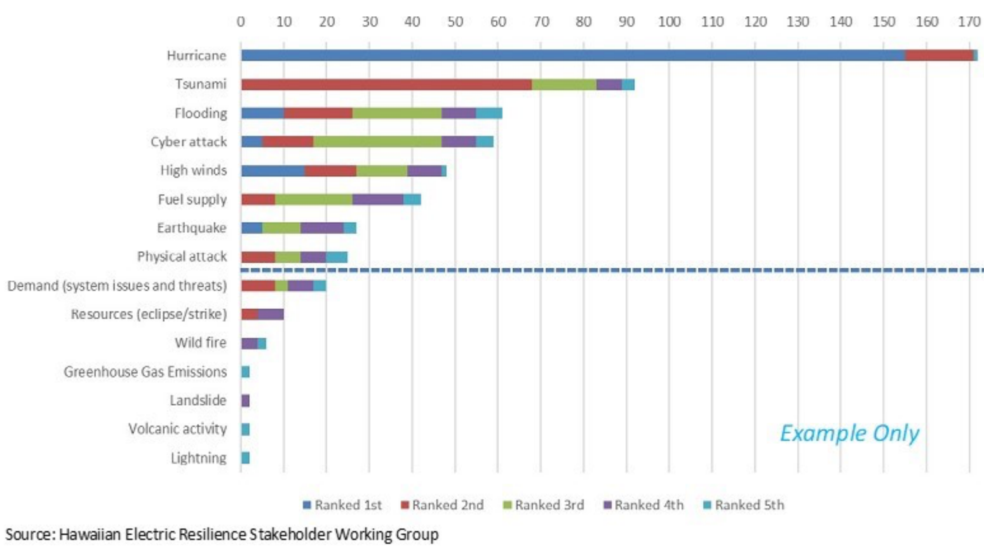


Figure 12. Stakeholder Informed Threat-Risk Prioritization

25 Hawaiian Electric Resilience Working Group Report, 2019, is available at: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-and-community-engagement/working-groups/resilience-documents?msclkid=e1dca83ac0cf11ec9b6bdd075bd11085.

The scale, scope, and duration of disruptions also shape the economic impact of solutions. It is essential to unpack distribution resilience threats to gain the insights necessary for planning and solution development.

Unpacking distribution resilience threats is needed to gain the insights for planning and solution development

2.2.1.2 System-Level Load and DER Forecasts

System-level DER and customer load forecasts are key inputs to both resource planning and distribution planning. These forecasts reflect macroeconomic trends, policy changes, retail rates, technology advancements, and diffusion patterns. The load forecasts are developed using long-term forecasts of aggregate consumer energy consumption (demand and load profiles) for a specific area (e.g., state, utility service area). This base load forecast is adjusted to reflect the net effects of customer adoption of distributed generation, storage, electric vehicles, and other load-modifying devices.

System load and resource forecasts, inclusive of DER, reflect broad changes across a jurisdictional area and are not detailed to a specific location at the distribution system in an IRP. Distribution planning requires a more granular forecast that is derived from this system-level forecast along with the incremental DER identified in an IRP.

Distribution studies beyond the three-year horizon are inherently uncertain and complex given the underlying forecasts for load changes, DER adoption, microgrid development and electrification. Therefore, using several potential scenarios can be helpful to inform strategic direction in longer-term distribution plans.

As shown in Figure 13 below, there are various methods to help assess different levels of uncertainty ranging from a discernable future to one that may offer many potential pathways. Level 1 involves the use of deterministic “point” forecasts. This has been the historical approach distribution planners have employed. However, as uncertainty increases (e.g., DER adoption, electrification, and load changes due to climate change), as is occurring on many distribution systems, deterministic forecasts alone will no longer be viable for distribution planning. In response, many planners are incorporating assumption sensitivities and alternative scenarios (Level 2) related to the factors mentioned above. Alternative scenarios are effective for most distribution systems experiencing/anticipating higher DER/EV adoption over the next decade. A Level 3 analysis would involve probabilistic techniques, or minimally bookend scenarios with some sensitivities within the range to potential futures.

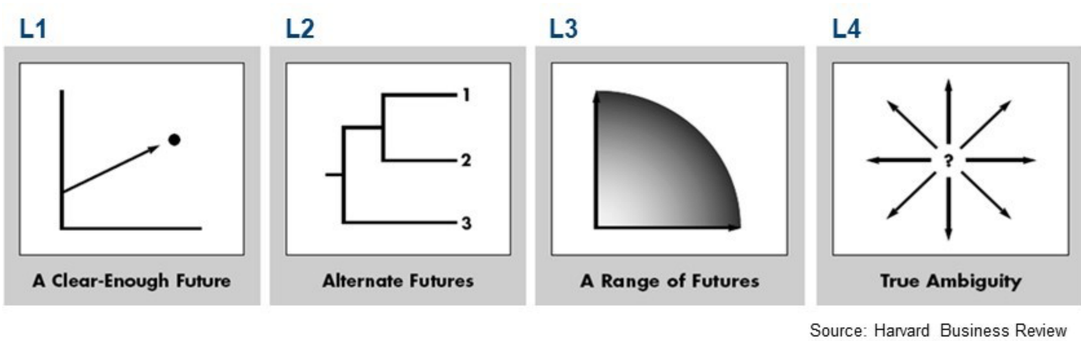


Figure 13. Four Levels of Uncertainty

A shift towards Level 3 scenario analysis is starting to be pursued as some distribution systems are experiencing significant DER adoption, electrification, and customer loads shaped by climate change. Specifically, changes in high and low temperature ranges are reshaping distribution level load characteristics, including creation of a second significant annual peak. That is, winter peaking systems are now also forecasting a large summer peak, and summer peaking systems are also seeing comparable winter peaks.

Longer-termed, scenario-based planning enables a robust consideration of the timing and magnitude of grid resilience needed over a 5- to 10-year period. As these longer-term plans are routinely updated every one to three years, there is an opportunity to update the associated grid modernization strategies to reflect changes in customer adoption of DER, advancement of technologies, policies, and other key factors. Long- and short-term planning is discussed in more detail in Step 5.

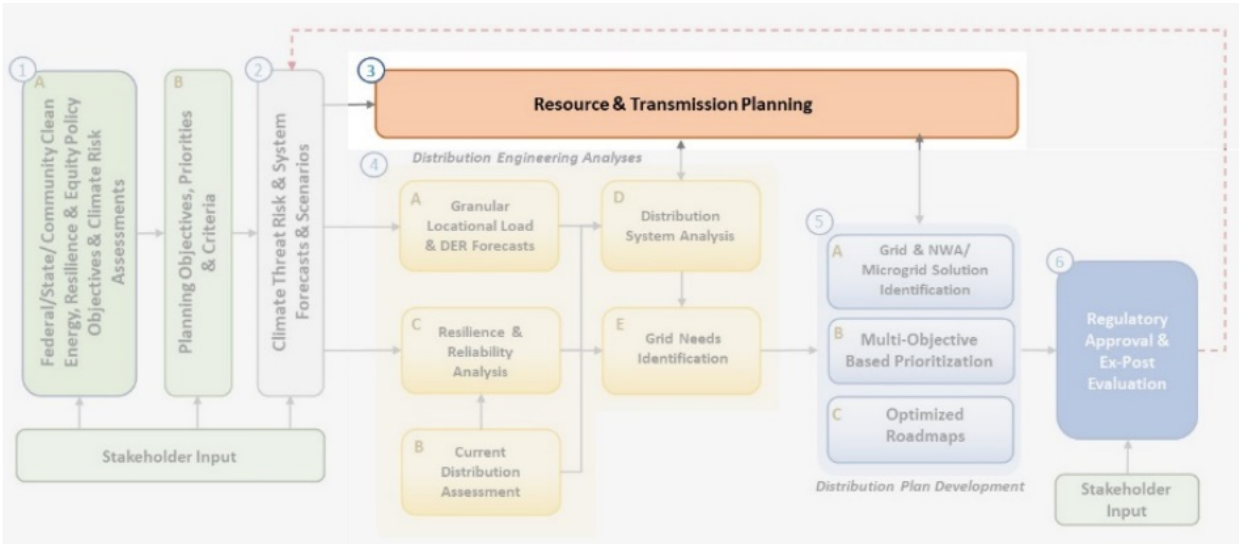
2.2.1.3 Local Community Planning

In addition to the local resilience planning, communities have increasingly identified specific goals and actions towards climate change mitigation, decarbonization activities, and importantly social equity and economic justice. As an example, the Sierra Club's "Ready for 100" initiative[26] is supporting local community development of 100% clean energy plans, including electrification, DER development, and microgrid development in conjunction with resilience objectives. A community such as Ann Arbor, Michigan, is an example pursuing both climate mitigation and adaptation strategic initiatives that inform planning.[27] Such local plans often directly change the requirements for the distribution grid in that locale and need to be considered in the planning process.

Additionally, a critical consideration for distribution planning is addressing energy justice. Energy justice refers to the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those disproportionately harmed by the energy system.[28] California's CalEnviroScreen[29] methodology is an example of a tool that can be used in the planning process to help identify California communities that are disproportionately burdened by multiple sources of pollution. When combined with identified disadvantaged and vulnerable populations the planning process can more effectively address the holistic needs of communities.

[26] Available at: https://www.sierraclub.org/ready-for-100
[27] Available at: https://www.a2gov.org/departments/sustainability/Adaptation-Resilience/Pages/default.aspx
[28] Energy Justice Network
[29] Available at: https://oehha.ca.gov/calenviroscreen

2.3 Step 3. Resource and Transmission Planning



The objective of integrating distribution with resource and transmission planning is to enable identification of opportunities for optimizing grid resources and infrastructure investments. The planning inputs and assumptions from Steps 1 & 2 also inform resource and transmission planning. Consistent use of these inputs is a minimum requirement to achieve alignment across these three planning activities that are often conducted by separate entities. This can be a challenge as the planning cycles may not coincide. Another consideration is addressing any alignment differences such that the planning analysis can be “integrated.” This integration may involve direct process and modelling integration and/or more simply through comparative assessment of the respective analysis results. No matter the sophistication of the approach, planning entities and stakeholders need a structured collaborative evaluation of the results. This can be a significant challenge for a number of jurisdictions, particularly those with relatively rigid RTO/ISO planning processes.

Consistent use of inputs is a minimum requirement to achieve alignment across resource, transmission and distribution planning activities that are often conducted by separate entities.

2.3.1.1 Integrated Resource Planning

Integrated resource plans (IRP) identify the incremental generation, storage, and demand-side management resources required to meet changes in energy demand over a long term, often 10–20 years. Resource plans increasingly include identification of additional distributed generation, storage, demand management, and energy efficiency programs needed to contribute to overall resource needs for energy, capacity, and ancillary services. Plans for the incremental use of these distributed resources are combined with consumer DER adoption forecasts to inform distribution planning.

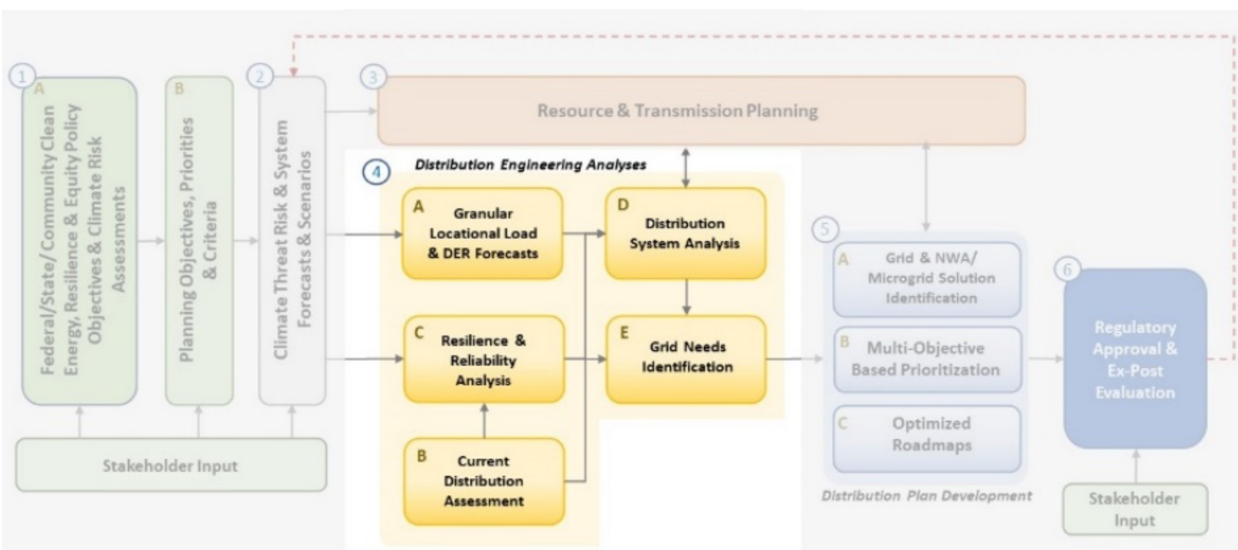
Long-term, system-level, net-load forecasts are a key input to an IRP as discussed above. These forecasts include customer adoption of DER to create a baseline for determining incremental resource needs. An IRP also addresses contributing factors that impact electricity supply and delivery. These also include renewable portfolio standards, electrification, as well as DER (including energy efficiency) policies at both federal and state levels.

2.3.1.2 Transmission Planning

Transmission planning is the process of planning and implementing a resilient, operationally stable, and cost-effective system to share generation resources between service areas, and transport power to and from distribution systems. The fundamental aspects of transmission planning address operational stability under various forecast conditions and contingencies, as well as resilience considerations based on various threat-risks. Additionally, transmission planning is a key element in comprehensive transmission, distribution, and resource planning.

As such, transmission planning is required to anticipate how supply, storage, load, distribution, and related power flows are intertwined.[30] These transmission planning analyses are conducted at regional, intraregional, and utility service area scales. The integration with distribution planning becomes more important at the utility service area level given the increasing bi-directional power flows and grid services across the transmission-distribution interface at substations. For example, an increasing number of local transmission systems are experiencing hosting capacity constraints related to DER adoption occurring at the distribution system level. There are many destabilizing factors that must be considered in transmission planning: higher integration of renewables, aging infrastructure, increasing loads, cyber threats, and decrease in sources of supply[31]. There is a large body of work on the role of transmission in resilience objectives, but typical transmission planning processes have not yet adapted to encompass distribution level resilience efforts.

Step 4. Distribution Engineering Analyses



Distribution engineering analyses apply the planning inputs and criteria developed in Steps 1 and 2 to determine needed system upgrades. These analyses span a range of engineering

30 J. Lau and B. Hobbs, Electric Transmission System Research and Development: Economic Analysis and Planning Tools, DOE, 2021.

31 Resiliency Planning for the Transmission Grid, ABB 2013. https://library.e.abb.com/public/041ac7ae0de9e6a7c1257bfe0065b3de/ABB-755-WPO.pdf

considerations based on more granular forecasts of DER and load characteristics, as well as granular resilience threat-risks. Each of the related sub-steps (4A through 4E) are discussed in its typical sequential order performed starting with converting system forecasts into granular forecasts (4A) and ending with an identified set of grid needs (4E). Additional discussion of reliability and resilience analysis is provided based on leading practices.

2.3.2 Granular Locational Load & DER Forecasts

Distribution planning requires a closer examination of the potential changes to load and DERs at the level of a substation, feeder, and in some cases sections of a feeder. This involves developing a granular locational forecast as well as more detailed temporal forecasts. These locational forecasts incorporate information regarding specific new housing and commercial developments based on existing or anticipated customer service requests, DER adoption and use patterns, as well as other relevant information that will shape the forecast.

System forecasts of DER adoption and their use inform the development of more "bottom-up" granular locational forecasts that are applicable to the specific distribution planning areas under assessment. The aggregate results are typically compared with system-level projections; ideally, the granular distribution forecasts in aggregate comport with the system-level forecasts.

Distribution planning requires a closer examination of the potential changes to load and DERs at the level of a substation, feeder, and in some cases sections of a feeder.

Distribution locational forecasting also involves development of circuit-level load forecasts. This analysis draws upon substation transformer (and circuit) loading data sourced from a SCADA system, historical circuit data (e.g., from load studies), and customer meter readings (i.e., AMI or other metering, as available). Forecasted increases in electricity demand due to increasing temperature extremes combined with electrification is becoming a challenge for traditional design standards and operational considerations.

An example of the development of locational DER forecasts is illustrated in Figure 14 below from Southern California Edison. This figure is from a presentation on the adaptation of system-level DER forecasts and related uncertainty considerations held in the California Distribution Forecasting Working Group.[32] These granular locational forecasts in turn inform both near-term and longer-term distribution planning.

[32] Institute of Electrical and Electronics Engineers Standards Association, "IEEE Guide for Electric Power Distribution Reliability Indices," (2012), accessed June 2020, https://standards.ieee.org/standard/1366-2012.html.

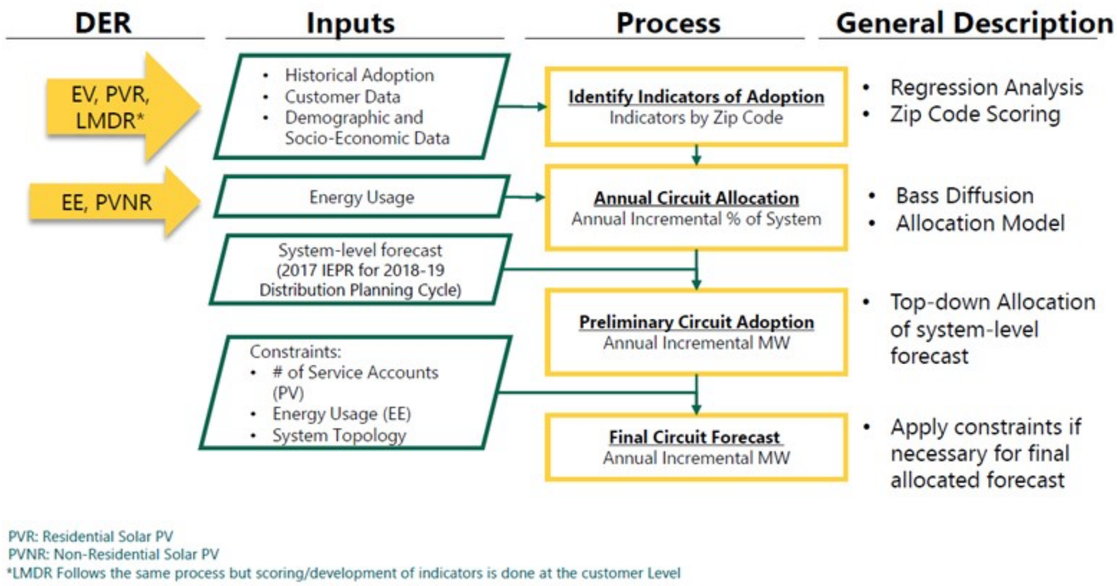


Figure 14. SCE's Granular DER/Load Forecast Process

2.3.3 Current Distribution Assessment

Any planning effort must begin with a clearly established starting reference point. In distribution planning, this reference point is the existing system condition and operational performance since the last plan. System condition refers to the "health" of individual infrastructure components (e.g., service transformer, pole, substation breaker), whereas operational performance refers to the performance of both individual pieces of equipment and apparatuses, as well as the collective system. Determining system condition requires effective data on distribution infrastructure including relative age, current condition, and stress conditions experienced (e.g., faults and overloads), among other sources. Determining operational performance requires data on the performance metrics of equipment, feeders, and systems. That data is then used to maintain customer service quality, as well as meeting reliability and resilience criteria.

Starting reference point is the existing distribution system condition and operational performance since the last plan.

2.3.3.1 System Condition

The assessment of the current asset condition and operational performance of a system is essential to determine compliance with planning criteria and service standards to fulfill obligations to provide safe, reliable service to customers at a reasonable cost. This assessment includes determining the current condition of grid assets, asset loading, asset utilization, feeder reliability, and substation reliability. These assessments are done in relation to standards and operational performance criteria. In addition, monitoring, tracking, and assessing the performance of distribution equipment allows utilities to plan and implement timely corrective actions. These actions are used to achieve desired resilience and reliability objectives and/or standards. Determining asset condition requires effective data on distribution infrastructure, including relative age, current condition, and stress conditions experienced (e.g., faults and overloads), among other aspects.

2.3.3.2 Operational Performance

Operational performance assesses the performance of the distribution system since the previous distribution plan (typically, the previous year's annual plan). It helps identify the performance required of equipment and control systems to maintain customer nominal voltage, as well as customer exposure to outages. This performance information provides the basis for identifying the frequency, duration, and nature of outages as reported in the IEEE 1366 standard[33] on reliability, e.g., the System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI). These reliability metrics are typically reported by utilities annually and used to benchmark performance against peer utilities with similar distribution system characteristics. Benchmarking results are used to inform capital investment prioritization (e.g., focusing efforts on improving the worst-performing feeders).

2.3.4 Resilience and Reliability Analysis

Resilience and reliability analyses assess a distribution system's capability to withstand potential threats (large and small) and recover quickly. Resilience and reliability planning cover a spectrum of event types as outlined below:

- **Reliability events** have a local impact with short duration outage—generally less than 24 hours and not classified as "Major Events" according to IEEE 1366.
- **Resilience events** cause larger geographic impact on distribution and/or bulk power system with long-duration outage—typically greater than 24 hours and classified as "Major Events" according to IEEE 1366. Distribution-level resilience events occur when there are similar infrastructure failures as those in reliability events (e.g., wires down, poles broken, transformer failure, fuses blown) but at a greater scale involving an extended outage duration.

The fundamental scale and duration difference between resilience and reliability events is illustrated in Figure 15.

[33] Institute of Electrical and Electronics Engineers Standards Association, "IEEE Guide for Electric Power Distribution Reliability Indices," (2012), accessed June 2020, https://standards.ieee.org/standard/1366-2012.html.

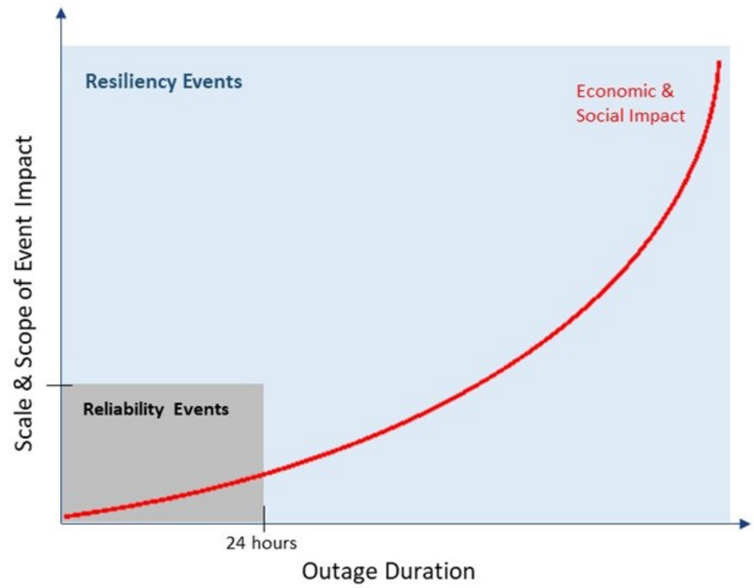


Figure 15. Reliability-Resilience Event Continuum

2.3.4.1 Reliability Analysis

Reliability planning is typically evaluated in the context of performance based on reliability indices in IEEE 1366 that reflect the annual average duration and frequency of outages experienced by utility customers as well as other key performance indicators by feeder, region, and service territory. This performance assessment also usually includes identifying worst-performing circuits and conducting associated root cause analysis.

For example, Ohio's utility code on distribution circuit performance[34] requires an annual performance report and remediation plan that provides information for each reported worst-performing distribution circuit (i.e., the worst 8 percent of all circuits), including:

- Circuit characteristics (e.g., number of customers and critical facilities, etc.),
- Each circuit's service reliability metrics related to number of momentary and sustained outages,
- Number of safety and reliability complaints,
- Any major factors or events that specifically caused the circuit to be reported among the worst performing circuits and, if applicable, the analysis performed to determine those major factors.

Most utilities conduct similar, detailed engineering analyses on the worst-performing circuits to identify root causes of poor performance and service interruptions. These analyses include location and duration of the interruptions, number of customers affected, root causes (e.g., weather events, equipment failure, animal contact, human contact), and physical environmental characteristics (e.g., surrounding vegetation) of the circuits.

[34] LAWriter Ohio Laws and Rules, "Distribution Circuit Performance," Ohio Administrative Code Chapter 4901:1-10-11, accessed June 2020, http://codes.ohio.gov/oac/4901:1-10-11.

2.3.4.2 Resilience Analysis

One element of resilience analysis involves applying downscaled forecasts of climate change to identify specific grid asset vulnerabilities. This involves a multi-layered approach given the multiple climate-based threats as identified in the Hawaii example in Figure 12. Each risk-threat is geographically assessed in relation to specific grid assets. One layer for utilities with coastal facilities is applying sea level rise forecasts to a service area to identify grid infrastructure at risk. Figure 16 illustrates such an analysis identifying substations at risk given certain levels of sea rise in Southern California.[35] A similar analysis is conducted for other types of flooding risks.

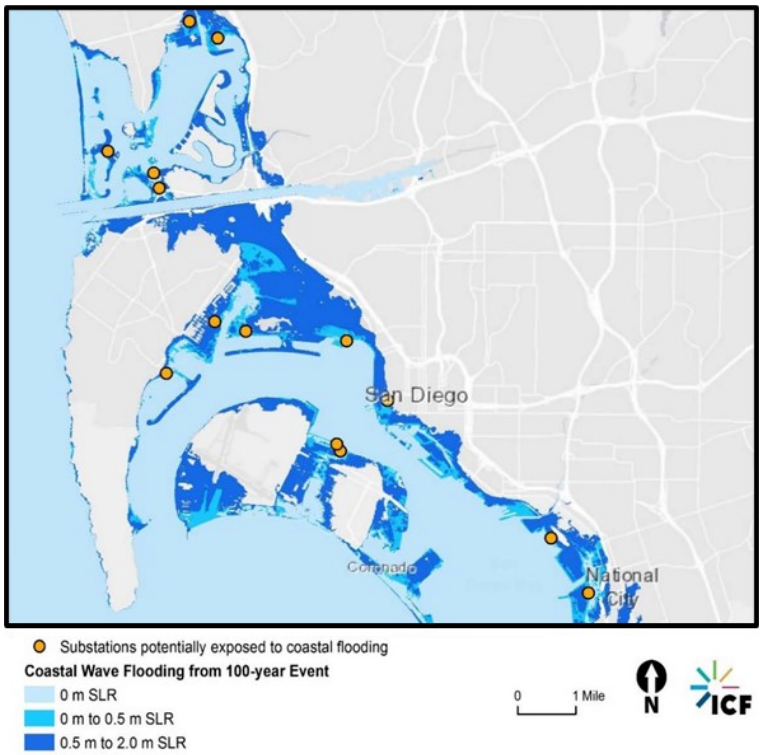
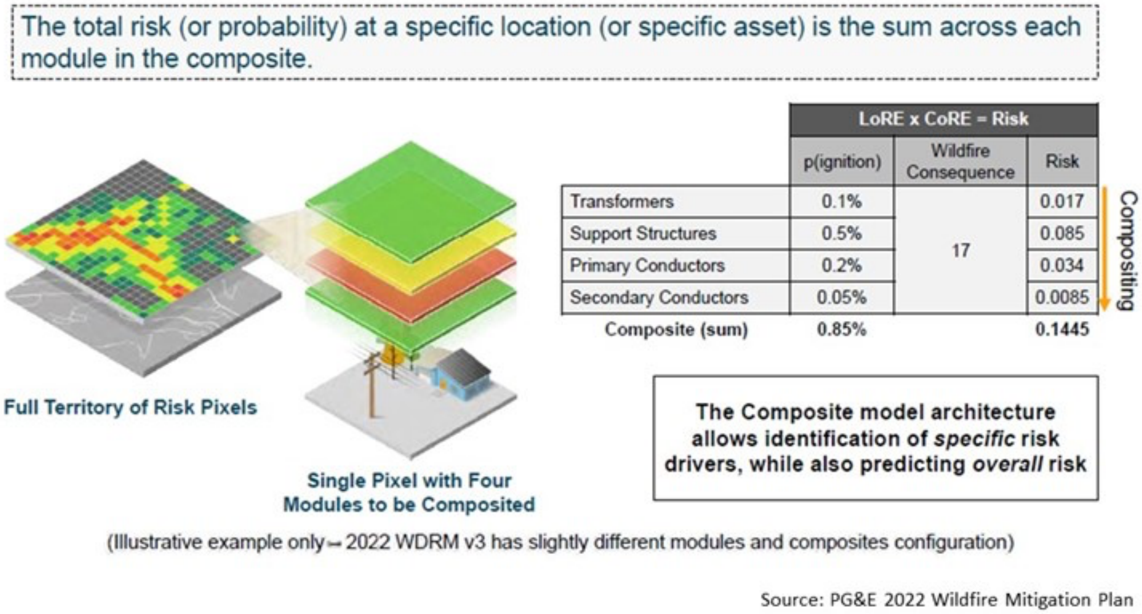


Figure 16. Sea Level Rise Risk-Threat Identification

Another layer of threat risk analysis is that done for wildfire risks due to long-term climate impacts on vegetation combined with weather conditions involving wind, humidity and temperature. The California Public Utility Commission (CPUC) produced High Fire-Threat District (HFTD) maps to identify areas of the state most at risk for wildfires and related potential ignition risk. The CPUC also provided a public online interactive geospatial map.[36] These HFTD maps and the state-level hazards assessment in Michigan (**Error! Reference source not found.**) are useful for identifying broad areas and communities of risk but are not sufficient to determine specific grid risk threats. For grid resilience planning, it is necessary to apply downscaled weather information to identify very specific grid infrastructure (i.e., apparatus and equipment) in specific locations. This type of granular assessment for wildfire risk is illustrated below in Figure 17.

[35] ICF, Rising Seas and Electricity Infrastructure: Potential Impacts and Adaptation Options for San Diego Gas & Electric (SDG&E), California Energy Commission, 2018. Available at: https://www.energy.ca.gov/sites/default/files/2019-11/Energy_CCCA4-CEC-2018-004_ADA.pdf
[36] https://capuc.maps.arcgis.com/apps/webappviewer/index.html?id=5bdb921d747a46929d9f00dbdb6d0fa2



	LoRE x CoRE = Risk		
	p(ignition)	Wildfire Consequence	Risk
Transformers	0.1%	17	0.017
Support Structures	0.5%		0.085
Primary Conductors	0.2%		0.034
Secondary Conductors	0.05%		0.0085
Composite (sum)	0.85%		0.1445

Figure 17. PG&E Risk Identification Method

This reliability and resilience analysis solution identification phase of Step 5A in Distribution Plan Development is incorporated with the other planning considerations, such as DER and electrification forecasts to conduct the power engineering studies as part of the Distribution System Analysis to inform the solution identification phase of Step 5A in Distribution Plan Development.

2.3.5 Distribution System Analysis

Distribution system analysis is the heart of the engineering analyses as the laws of physics ultimately dictate the physical operation of the electric system. The purpose of distribution system analysis is to ensure that the distribution system can meet the planning objectives (Step 1) while maintaining safety and power quality within established standards. This requires a rigorous power flow analysis of the current system based on the all the outputs of the prior steps discussed above. This includes the planning objectives and criteria, forecasts and scenarios, system condition, resilience and reliability factors, and related operational data. The system engineering analyses involve assessing thermal loading, power quality, protection, contingency and hosting capacity. Each of these analyses are briefly described below. A more complete discussion is included in the DSPx Guidebook.[37]

Distribution system analysis is the heart of the engineering analyses as the laws of physics ultimately dictate the physical operation of the electric system.

[37] P. De Martini, J. Taft, et al., Modern Distribution Grid, Volume IV: Strategy and Implementation Planning Guidebook v1.0, DOE-OE, 2020; located at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

2.3.5.1 Thermal Loading Analysis

Thermal loading analysis includes assessing forecasted equipment loading in the context of equipment and conductor ratings for both normal and contingency conditions based on power flow in either direction.

2.3.5.2 Power Quality Analysis

Power quality analysis, primarily voltage analysis, examines the impact of loading levels on overall feeder voltage and on the voltage for specific customers under normal and abnormal (e.g., outages or scheduled maintenance) conditions when circuits are reconfigured to stay within the applicable ANSI standard. Harmonic analysis is typically done on an as-needed basis; for example, in specific instances of unusual customer device/equipment characteristics.

2.3.5.3 Protection Analysis

Protection analysis for distribution systems with high DER and/or microgrid development will be an important consideration in the system analysis because the output of distributed generation or storage resources can cause mis-operation of distribution protection systems that lead to failures.

2.3.5.4 Contingency Analysis

Contingency analysis evaluates distribution conditions when outages occur, and alternative transformers and/or circuits are then used to restore all or a portion of the load. Metropolitan radial distribution systems are often designed to withstand planned and unplanned contingency or emergency situations to enhance reliability and resilience.

2.3.5.5 Hosting Capacity Analysis

Hosting capacity analysis estimates the amount of DER that can be accommodated, regardless of location, on a sub-transmission distribution system, substation, or a feeder without violating power quality, thermal loading, or protection requirements. Hosting capacity has largely been discussed in terms of interconnection assessment but forecasting hosting capacity analysis can also inform the planning process and identify circuit constraints to be resolved to facilitate DER growth.[38] Further, to the extent that distribution-connected DER provides wholesale energy services, it is necessary to consider the deliverability of that DER across the distribution system to the wholesale transaction point.

[38] Hawaiian Electric Companies, Planning Hawai'i's Grid for Future Generations, Integrated Grid Planning Report (2018), accessed June 2020, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20180301_IGP_final_report.pdf.

2.3.6 Grid Needs Identification

Grid needs identification involves identifying the specific substations and circuits where planning criteria is already violated, or forecast to become violated over the planning period.

Grid needs identification involves consolidation of the several preceding engineering analyses regarding specific substations and circuits where planning criteria are already violated, or forecasted to become violated over the planning period. The initial efforts in several states, such as California, requires the summation of this information into an annual Grid Needs Assessment (GNA) report as part of their Distribution Investment Deferral Framework (DDIF). The objective of this GNA is "to allow the Commission and parties to review the list of grid needs along with the planning assumptions that underlie these needs, in order to provide transparency into the Investor-Owned Utility's (IOU) distribution planning process."[39] Similarly, other states have adopted similar requirements that focus on four areas for potential non-wires alternatives: capacity, voltage support, reliability, or resiliency. A GNA typically includes identification of substations and circuit locations with deficiencies, forecasted planning criteria violations (e.g., overload, voltage variation, reliability deficiency, etc.) of the existing equipment, and the forecasted timeframe by which the deficiency must be addressed. An example of the type of data provided in a GNA is listed in Table 1 below adapted from Hawaiian Electric.[40]

Table 1. Grid Needs Assessment Data

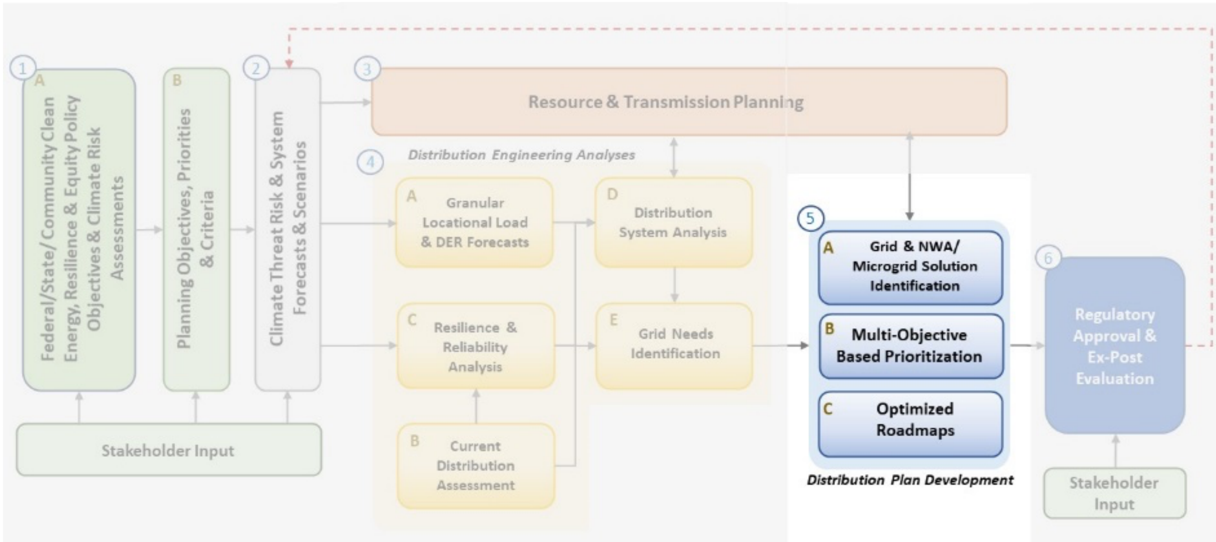
Specification	Definition
Substation	Transformer asset identification
Circuit	Feeder asset identification
Distribution Service Required	Distribution Capacity, Voltage Regulation, Reliability and/or Resilience
Primary Driver of Grid Need	Defines whether the identified grid need is primarily driven by: DER growth, demand growth, reliability, resiliency, other factor(s), combination of factors
Operating Date	The date at which traditional infrastructure must be constructed and energized, in advance of the forecasted grid need to maintain safety and reliability
Equipment Rating (MW)	Defines the equipment's rated capacity
Deficiency (%)	The deficiency % is the deficiency divided by the rating for each of the forecasted years, or deviation from other planning criteria

These GNAs provide the basis for the development of distribution implementation plans involving identification and prioritization of various alternatives for each identified need.

[39] California Public Utility Commission, Decision on Track 3 Policy Issues, D.18-02-004. 2018. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF

[40] Adapted from Hawaiian Electric's Grid Needs Assessment & Solution Evaluation Methodology, 2021. Available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/solution_evaluation_and_optimization/20210330_wg_seo_deliverable_draft.pdf

2.4 Step 5. Distribution Implementation Plan Development



2.4.1 Long-Term and Short-Term Planning

Distribution implementation plans translate the grid needs identified in the previous distribution engineering analyses step into actionable long-term and nearer-term expenditure plans. This requires taking a holistic view to address both normal conditions and resilience needs to optimize expenditures equitably. This includes a recognition that modern grids are dependent on a resilient foundation. The result is an investment pyramid, shown in Figure 18, that is comprised of layered interdependent capabilities to achieve the set of objectives identified in Step 1 discussed earlier. The investment pyramid shows the prioritization of grid modernization investments and is structured hierarchically where the bottom most layers must be addressed prior to moving to more advanced layers at the top. These layers involve addressing the following capabilities as part of a long-term distribution plan and a related annual short-term action plan (top to bottom):

- Enabling community and customer resilience solutions.
- Enhancing reliability & providing additional resilience functionality.
- Improving customer reliability & operational flexibility.
- Foundational safety, resilience, & service quality requirements.

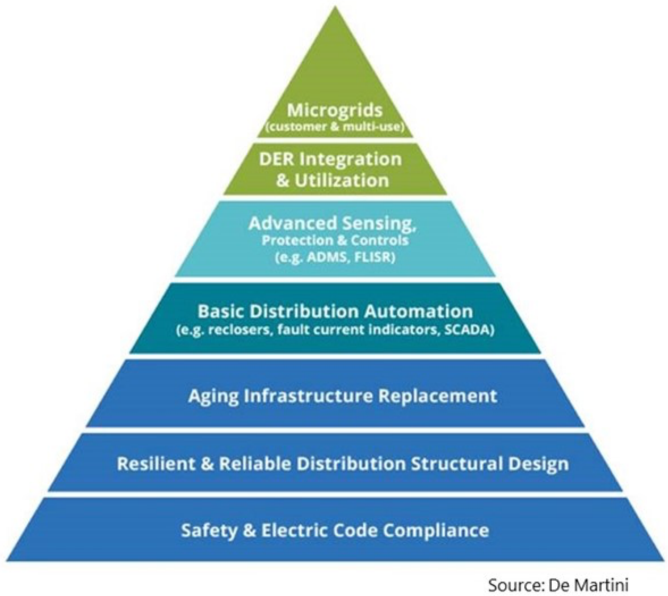


Figure 18. Distribution Modernization Pyramid

2.4.1.1 Long-Term Planning

Long-term distribution planning, typically 10 years, is more strategic in nature and is undertaken to understand the potential major grid changes that may be needed and any adjustments to ongoing programmatic efforts. Long-term plans primarily focus on identifying and assessing the systemic impacts to an existing distribution system design. Examples of systemic impacts may include fundamental changes to the flow of electricity from exporting DER and weather-related climate change impacts, as well as socioeconomic conditions. They also determine any needed longer-term operational changes that will be necessary. This includes, for example, addressing large-scale DER, microgrid, and electrification utilization. This contrasts with the near-term plans that are focused on specific immediate grid needs within the context of the longer-term plan and tactical projects that are required within two years.

Longer-term distribution planning is cyclical reflecting progress of programmatic asset plans, adjustments based on actual DER and electrification adoption. Additionally, these plans allow for opportunities to optimize distribution upgrades, modernization plans given technological advancements, procure non-wires alternatives, and allow for microgrid developments.

2.4.1.2 Short-Term Planning

Short-term planning is typically conducted annually as an input into the utility annual budget planning process to determining the one- to two-year incremental grid needs and areas for operational performance improvement. This planning process is used to refine internal utility capital and operational budget allocations in order to define specific project and program activities for the following year. A representative illustration of a utility annual distribution budget allocation is illustrated below in Figure 19. The blue shaded areas either directly (dark blue) or indirectly (light blue) contribute to grid resilience.

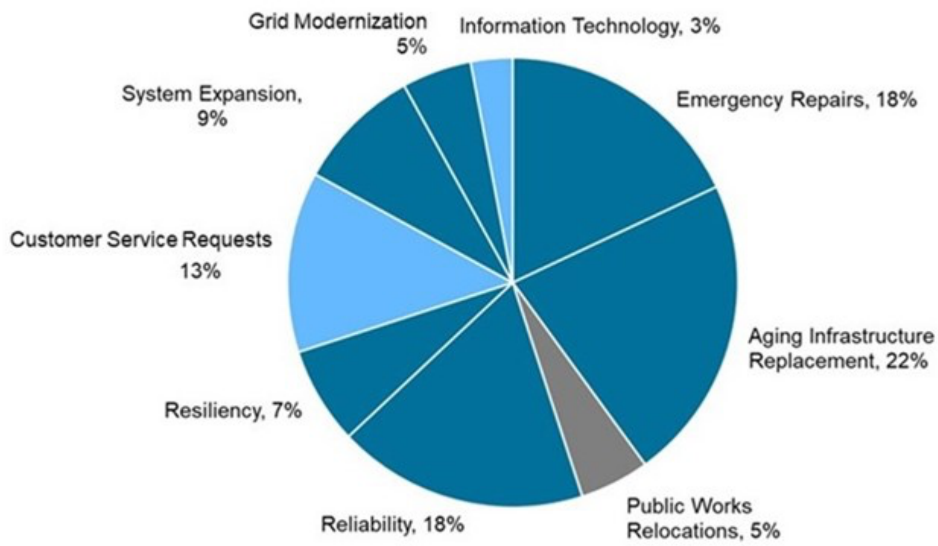


Figure 19. Annual Distribution Budget Allocation Example

This tactical planning effort is informed by the longer-term strategic roadmap and considerations. The actual implementation of the utility's investment, as well as those of customer and third-party non-wires alternatives in turn, inform cyclical updates to the long-term plan.

Long- and short-term implementation plan development involves three sequential activities: a) identification of potential solutions to address the grid needs, b) multi-objective prioritization of the solutions, and c) development of flexible, optimized implementation roadmaps.

2.4.2 Solution Identification

Solution identification to address grid needs involves consideration of a range of potential solutions including:

Goal is to identify solutions that address multiple planning objectives that provide the greatest relative value.

- No-cost solutions, such as operational changes to system configuration,
- Low-cost solutions such as new design standards,
- Capital expenditures on system improvements such as resilience improvements, programmatic asset replacement, infrastructure upgrades, and modernization investments, and
- Various non-wires alternatives.

Increasingly, the goal of this step is to identify solutions that address multiple planning objectives that provide the greatest relative value. The earlier integrated distribution planning papers[41,42] and related state efforts[43] to launch integrated distribution system planning discussed the solution identification methods for addressing load growth and DER adoption. This paper recognizes this continued need plus the increasing requirement of resilience solution evaluation as part of a multi-objective based integrated distribution plan. The following discussion adds to the earlier work by providing emerging best practices regarding resilience solution identification.

2.4.2.1 Resilience Solution Identification

For context, this discussion is focused on identification of solutions that may prevent an outage or reduce the scope of an outage through corrective actions as illustrated in Figure 20. This analysis is informed by the grid needs identified in Step 4, which considered the threat-risks and other identified needs.

In Figure 20, Phase II activity involves preparing for emergency coordination of personnel, equipment and inventory. It is a critical activity, but typically addressed outside the distribution engineering analyses. Similarly, the Phase III restorative activity involving the operational implementation of the emergency coordination effort to repair damaged circuits and restore service is also outside the distribution planning process.

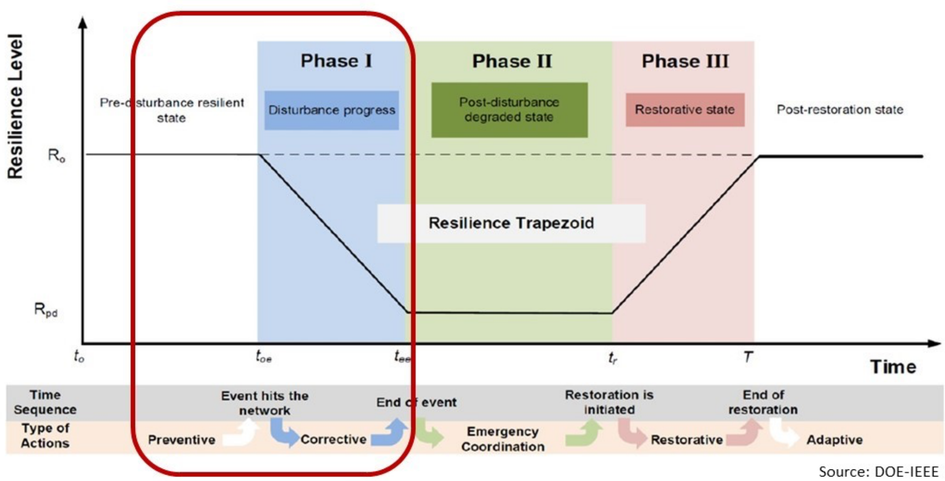


Figure 20. DOE-IEEE Resilience Framework

Fundamental to distribution resilience investment planning in Step 5 is determining a risk management strategy integrated within overall distribution planning. This involves using the specific infrastructure threat-risks identified in Step 4C to determine preventative and mitigation solutions. The “bowtie method,” shown in Figure 21, is a best practice in many sectors and increasingly in use in the electric industry. This method translates the earlier threat-risk assessment and asset vulnerabilities in Step 4C into a combination of preventative and mitigative solution options. These solutions may include various grid infrastructure upgrades, as

[41] P. De Martini, Integrated Distribution Planning, ICF-DOE. 2016. Available at: https://www.energy.gov/sites/default/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf
[42] GridLab, Integrated Distribution Planning, A Path Forward. 2018. Available at: https://gridlab.org/works/integrated-distribution-planning/
[43] An example is Oregon Public Utility Commission’s Distribution System Planning, https://www.oregon.gov/puc/utilities/Pages/EO20-04-UtilityServices-Activities-DSP-Interconnection.aspx

well as customer and third-party solutions. A bow-tie approach helps identify where and how solutions would have the greatest impact for customers and communities.

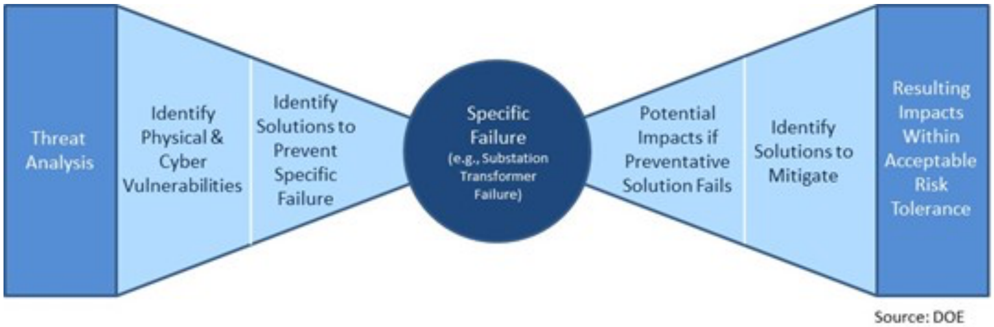


Figure 21. Bowtie Resilience Solution Identification Method

Preventive solutions are shown on the left side of the bowtie. Preventative solutions involve those that can either avoid (e.g., undergrounding) or withstand (e.g., pole hardening) a specific risk. Mitigation solutions can reduce the scope or duration of a resulting outage caused by a major event. Mitigation solutions are shown on the right side of the bowtie. The specific prevention and mitigation solutions are identified through both grid options, as well as by employing potential customer and third-party solutions. The utility asset options may involve vegetation management, hardening, undergrounding, and increasing automated switching flexibility, for example. Third-party solutions may involve microgrids, local generation and storage resources, and load management.

A portfolio of grid, customer, and 3rd party solutions is often needed to fully address societal resilience objectives.

Given the range of threats and various needs of communities and customers, a portfolio approach, shown in Figure 22, is often required to efficiently address resilience objectives including equity considerations. This includes multi-community and community-scale grid-based solutions, as well as specific point solutions for critical facilities and vulnerable populations. Collectively, however, the point solutions may not achieve all the societal benefits intended by government policies in an effective or efficient manner. As such, a portfolio of grid, customer, and third-party solutions is often needed to fully address the societal resilience objectives.

Figure 22. Resilience Solution Portfolio Matrix

An important dimension in the identification of potential solutions is effective engagement of communities, vulnerable constituents, and third-party developers, with active participation of the utility. This involves a comparative assessment of the proposed solutions against the objectives and priorities identified by stakeholders in Steps 1 and 2. This is essential to align solution options with the planning objectives in order to achieve an appropriate portfolio that ensures the overall affordability, resilience, and efficiency desired.

2.4.3 Multi-objective Prioritization

Multi-objective prioritization involves the consolidation of the full set of solutions to address all the grid needs identified earlier in Step 4E of the process. The purpose is to develop a prioritized list of solutions for potential implementation owing to practical constraints, such as budget limits. The challenge is that this list will require normalizing the relative value provided by each solution given the disparate and conjoined needs addressed. For example, a solution that addresses a specific resilience risk needs to be compared to a solution that enables DER adoption on an equitable comparison basis to develop an overall prioritized list and ultimately an optimized expenditure plan. This is an emerging area of inquiry by regulators, utilities, and the research community.

Challenge is that prioritization requires normalizing the relative value provided by each solution given the disparate and conjoined needs addressed.

Therefore, the following discussion is intended to frame the considerations and provide a few early examples of how multi-objective prioritization is being incorporated, particularly in resilience planning. However, there is considerable research required to more fully develop a holistic multi-objective prioritization methodology. It is also important to recognize that it is not possible to apply simple cost-benefit analyses as is done for energy efficiency, for example. As described in the DSPx Guidebook[44], the nature of grid expenditures and non-wires alternative

[44] DSPx Guidebook, Chapter 5, Methodology to Evaluate the Cost-Effectiveness of Investments, p.108; located at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

more often than not do not fit the Standard Practice Manual[45] constructs for cost-effectiveness. This is increasingly recognized by state regulators.

Building upon the DSPx Guidebook approach to cost-effectiveness, the proposed multi-objective framework offered in this paper involves three additional sequential sub-steps:

1. Ranking planning objectives and criteria based on stakeholder input.
2. Normalizing the value contribution of each solution in relation to one or more objectives.
3. Developing a prioritized list based on a normalized value-spend efficiency metric.

2.4.3.1 Ranking Planning Objectives

The starting point for prioritization of solutions is the set of planning objectives identified at the start of the planning process in Steps 1 and 2. These objectives will each have attributes, such as timing, scope and relative importance. So, a challenge is determining a ranking or weighting method that appropriately provides foundational guidance on priorities. This is best accomplished through a stakeholder engaged process at the outset in Steps 1 and 2, and not left for determination toward the end of the IRDP process at this step.

The objectives from Steps 1 and 2 used for this initial prioritization step relate to specific grid infrastructure and operational capabilities. Prioritization of the multiple objectives may take the form of a relative ranking as illustrated in the example below. The objectives in this example combine policy and customer objectives with statutory operational requirements, such as safety and service compliance.

Planning Objectives Ranked (1-5)						
Safety (5)	Service Compliance (5)	Reliability (3)	Resilience (4)	Electrification (3)	DG/DS Integration (3)	Equity (4)

Figure 23. Objectives Ranking Example

The numerical ranking can be replaced with a percentage-based weighting method. It is recommended to provide sufficient differentiation in the ranking (or weights) of the selected objectives to facilitate the overall prioritization process. An early example of such a multi-objective ranking method for distribution plans was developed by DTE Energy.[46] The next step is to consider the relative value contribution of each proposed solution to achieve one or more of the planning objectives. Objectives related to electricity affordability are addressed in the subsequent cost-effectiveness steps in this prioritization process.

2.4.3.2 Normalize Solution Value Contribution

Each proposed solution identified has a specific value contribution to one or more planning objectives. Each objective has different performance criteria and therefore proposed solutions will need to be normalized to be able to comparatively assess them within a portfolio. For example, here are a few typical planning criteria that may require solutions:

[45] T. Woolf, and et al. National Standard Practice Manual, National Energy Screening Project (NESP), August 2020. Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

[46] DTE Electric Company's 2021 Distribution Grid Plan Final Report. pp. 82-90. Available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000Uc0pkAAB

- Service voltage compliance standards.
- Reliability criteria, such as a SAIDI goal.
- Safety compliance criteria regarding aging/damaged infrastructure replacement (e.g., wood pole decay based on compliance inspections).
- Planned operational criteria such as exceeding normal and emergency ratings.
- Planned operational criteria to enable DER aggregation.

Each of the criteria above have different value characteristics that are not easily translated into a simple cost-benefit analysis. This is further compounded as potential solutions may address more than one of the grid needs identified to address these criteria. As such, there is a need to normalize the relative value contribution of each solution. This enables a comparative assessment to develop an overall solution portfolio including expenditures for grid, and customer and third-party solutions.

One approach to assess value contribution is to consider evaluating a solution's (i.e., utility project or NWA) contribution toward achieving each objective in relation to the maximum ranking score. For example, if undergrounding a circuit fully addresses an important resilience threat then it would receive a score of "4" in the example ranking above in Figure 23. If it also addressed the resilience threat for an identified vulnerable community, then it would also receive a "4" regarding equity objective in this example. In practice, regulatory and utility efforts have begun to identify this relative contribution to resilience and equity. In California, the Wildfire Mitigation Planning[47] process also includes methods for determining the relative contribution to improving resilience as shown below (Figure 24).

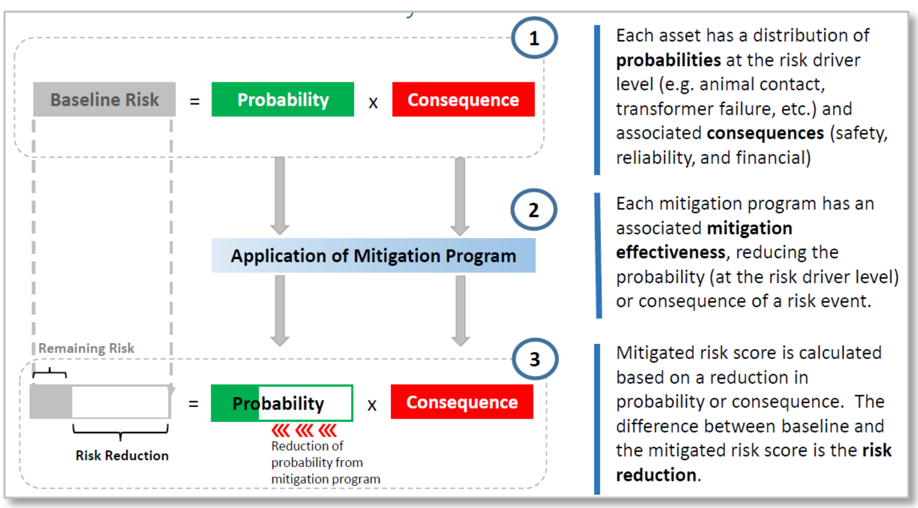


Figure 24. SCE Resilience Risk Reduction Evaluation

Likewise, early efforts at assessing a project's value in addressing equity issues in the context of resilience needs of vulnerable communities has been pursued in California's Microgrid Incentive Program (MIP). That program is specifically focused on enabling development of community microgrids. While this program funding is through a rate surcharge outside of a

[47] California Public Utilities Commission (CPUC), Wildfire Safety Division (now Energy Safety) 2021 Wildfire Mitigation Plan Guidelines Template. Available at: https://www.cpuc.ca.gov/industries-and-topics/wildfires/utility-wildfire-mitigation-plans

distribution planning process and utility distribution budget, there are insights into how stakeholder priorities can be incorporated into a method for determining the relative contribution to an equity objective. Figure 25 below is an excerpt from a draft proposal discussed in MIP stakeholder workshops showing the customer and community benefits scoring method (note: other project attributes were also scored).[48]

<table>
<tr><th>Benefit Scoring Category</th><th>Subcategory</th><th>Scoring Parameter / Criteria</th><th>Validation</th><th>Points</th><th>Points Cap</th><th>Max Points</th></tr>
<tr><td rowspan="4">Customer & Community Benefits</td><td>Low Income Customers</td><td>Number of CARE/FERA customers within MIP Project</td><td>Utility Records</td><td>0.1</td><td>8</td><td rowspan="4">50</td></tr>
<tr><td>Vulnerable Customers</td><td>Number of AFN/Medical Baseline/Life Support customers within MIP Project</td><td>Attestation from Authority having Jurisdiction</td><td>0.2</td><td>10</td></tr>
<tr><td rowspan="2">Critical Facilities (CF)</td><td>Number of Critical Facilities within MIP Project Boundary</td><td>CPUC Definition</td><td>5</td><td rowspan="2">30</td></tr>
<tr><td>Number of Critical Facilities within MIP Project</td><td>CPUC Definition</td><td>10</td></tr>
</table>

Figure 25. Customer & Community Benefits Excerpt

The resulting equity "score" for a specific solution would then need to be compared in relation to achieving the overall equity objective. The resulting equity contribution value is then included along with the other value contributions the solution may provide. For example, methods for determining the relative value of reliability improvements estimate the relative improvement in regard to standard metrics such as SAIDI and CAIDI, as well as related performance objectives. The result can then be used to normalize in relation to the associated ranking for reliability and equity objectives as conceptually illustrated in Figure 26.

[48] Proposed Microgrid Incentive Program Implementation Plan of San Diego Gas & Electric Company (U 902-E), Pacific Gas and Electric Company (U 39-E), and Southern California Edison Company (U 338-E). Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M428/K469/428469637.PDF

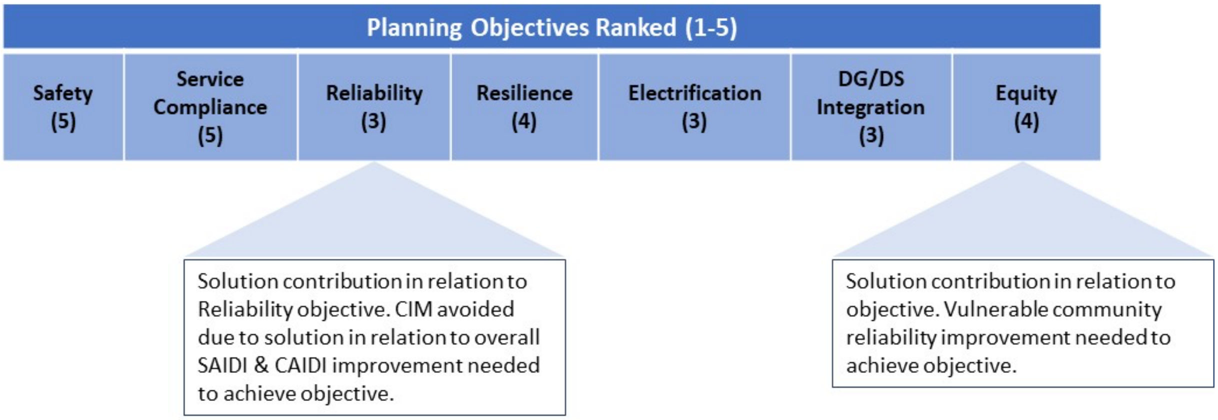


Figure 26. Solution Value Contribution Normalization

However, as illustrated in the equity example above, an important challenge is that many objectives do not have such clearly defined methodology for determining a solution's contribution to the overall desired outcome. As such, it may involve expert judgement (e.g., utility, stakeholder, or independent) with substantiation to assess the contribution of a solution's contribution. This is not unlike how many distribution projects and programs are justified in general rate cases and grid modernization applications. These will need to be more clearly described in relation to achieving defined objectives such that a normalized score can be supported.

2.4.3.3 Value-Spend Efficiency

The cost-effectiveness method proposed here is a value-spend efficiency (VSE) approach. VSE is an estimate of the normalized cost-effectiveness based on the relative value score and respective cost for a specific solution. This VSE method is a generalized adaptation of the California method and that employed by DTE Energy. A VSE score is determined for specific solutions by dividing the normalized total value score by the solution cost (i.e., capital investment or third-party solution expenditures) as shown in Figure 27. The resulting spend efficiency scores enable the creation of a prioritized list of solutions.

	Planning Objectives Ranked (1-5)									
Specific Projects	**Safety (5)**	**Service Compliance (5)**	**Reliability (3)**	**Resilience (4)**	**Electrification (3)**	**DG/DS Integration (3)**	**Equity (4)**	**Score**	**Cost ($mm)**	**Spend Efficiency (S/C)**
Tree Trimming[1]	5		3	3				11	$2.5	4.4
Undergrounding[2]	3		3	4	1	1	2	14	$5.0	2.8
Pole/Tower Hardening	2	2	3	4			1	15	$2.0	7.5
4kV Voltage Upgrade Conversions	4	4	2	3	3	3	3	22	$10.0	4.5
Substation Breaker Replacement[2]	5	5	3		1	1		15	$2.0	7.5
ADMS		3	3	3	2	3	1	15	$2.5	6.0
Field Automation[2,3]	3	3	3	3		1	2	15	$3.0	5.0
Advanced Metering	1	2	2	1	1	3	1	11	$2.5	4.4

1. Improved reliability & resilience supports greater consumer reliance on electrification
2. If program involves using larger conductor or higher capacity equipment
3. Improved reliability and resilience of grid improves the availability for DER to provide bulk power & grid services

Figure 27. Illustrative Value-Spend Efficiency Method

The next step is to translate this prioritized list of solutions into an optimized implementation roadmap reflecting the highest value contribution over a specific planning period relative to a given budget and resource (e.g., qualified workers and equipment to implement the plan) constraints.

2.4.4 Optimized Implementation Roadmap

Given the changing and uncertain future operating conditions and requirements for distribution systems, there is a need for a flexible, adaptive approach to the implementation of a modern grid. Managerial flexibility, for example, is needed to defer, avoid, proportionally deploy, and adapt. This is especially necessary given the expected long transformation time that grid infrastructure and modernization will take in most instances. Such flexibility designed into a roadmap and implemented can create value for customers. Crafting such a flexible approach involves a prioritized progression and periodic recalibration opportunities to achieve a more optimal implementation. The following discussion offers an approach to address this need.

Need for a flexible, adaptive approach to the implementation of a modern grid.

In practice, there are often two parallel plans, one for long-term solutions to address systemic grid needs, and one for potential intermediate capital deferral and/or resilience mitigation measures. Intermediate mitigation measures may include customer and third-party non-wires alternatives, temporary generation, or implementation of a storage or microgrid solution until a circuit can be undergrounded to address wildfire ignition risk. These long-term and intermediate solutions need to dovetail to achieve an optimal outcome for all ratepayers. Also, these plans will require implementation over several years and require adjustments as conditions change. For example, an integrated distribution plan often will have a 10-year horizon, with a related short-term plan that identifies specific projects for each year. As such, development of an optimal roadmap involves a multi-stage decision process, where a total plan is built up in 10 one-year stages in such a way that an overall objective is optimized.[49]

In this multi-stage decision process, the results from a preceding year become the initial conditions for the next year. The objective is to maximize a measure of total achievement of planning objectives within the bounds of certain key constraints (e.g., budget and resources). Also, the intent is for the total objective curve to rise as fast as possible over the course of the multiyear plan. For resilience, it would involve reducing outage risk for the benefit of the greatest percentage of population served. This would require an optimal combination of the preventative and mitigation measures. Therefore, the resulting total objective curve is a composite of two sub-curves, one for preventative measures and one for mitigation measures.

This method involves starting with the prioritized solutions and for each year in succession. Next, the measures are selected in order of relative value, but adjusted by applying the given constraints to determine limits on what can be done that year. Once that year's work plan is chosen, the objective curve is updated to show the cumulative results of the present year and any preceding years. The results of the current year plan include a stack of projects to be applied that year, along with how much of each project to apply (which determine that year's cost and contribution to cumulative risk reduction curve). The process continues in successive years until the full 10-year plan reflecting both the preventative and mitigation plans is complete as shown in Figure 28

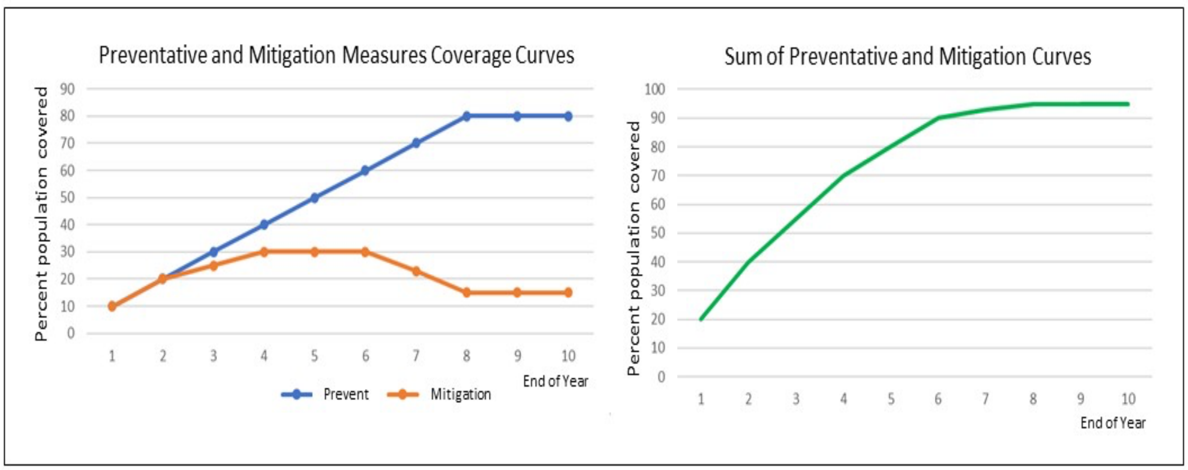


Figure 28. Example Curves from the Portfolio Roadmap Optimization Process

For example, a resilience objective may be to reduce the outage risk for the total percentage of a utility's service population by either long-term preventive solutions and/or intermediate mitigation solutions. In this example, it involves selecting a multi-stage plan that causes the resilience objective curve (in this case, the percentage of population covered) to rise as fast as possible, given the constraints that must be satisfied. These include constraints such as:

- Present year budget limit – the total cost of the measures for that year must not exceed the budget for that year.
- The total coverage must not exceed 100%.

[49] P. De Martini and J. Taft, Distribution Resilience and Reliability Planning, Pacific Northwest National Laboratory, January 2022. Available at: https://gridarchitecture.pnnl.gov/media/advanced/Resillience_Solution_Analysis_paper.pdf

- Amount of any measure to be used must not exceed the opportunity for that measure. For example, if the measure is undergrounding circuits, that measure cannot exceed the number of circuits remaining to be undergrounded at that stage.
- Amount of any measure must not exceed the resource limit for that measure in that year. For example, if the measure involves hardened utility poles, there may be a staffing resource limit on how many can be done in that year.

The starting point for each planning cycle are the a) cumulative results of previous years, b) updated constraints, and c) updated prioritized solution list. The next step is to select solutions from the prioritized list toward achieving the long-term cumulative curve objective. This involves determining how many of the prioritized and mitigation solutions can be implemented in the planning cycle within the given constraints. This use of a value-spend efficiency merit order allocation is similar to the use of merit order dispatch of generators in a bulk power system.

Example of these two complementary preventative and mitigation plans are reflected in the California Wildfire Mitigation[50] plans. The illustration below in Figure 29 shows the cumulative outage risk reduction from Public Safety Power Shutoff (PSPS) events due to both the implementation of wildfire prevention measures and mitigation measures.

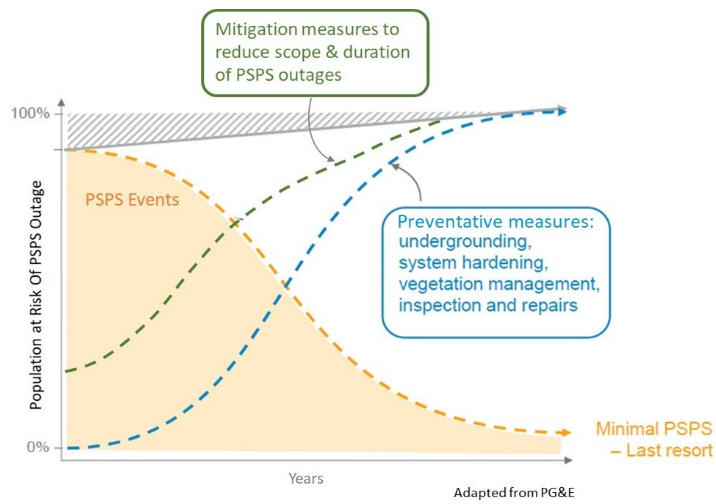
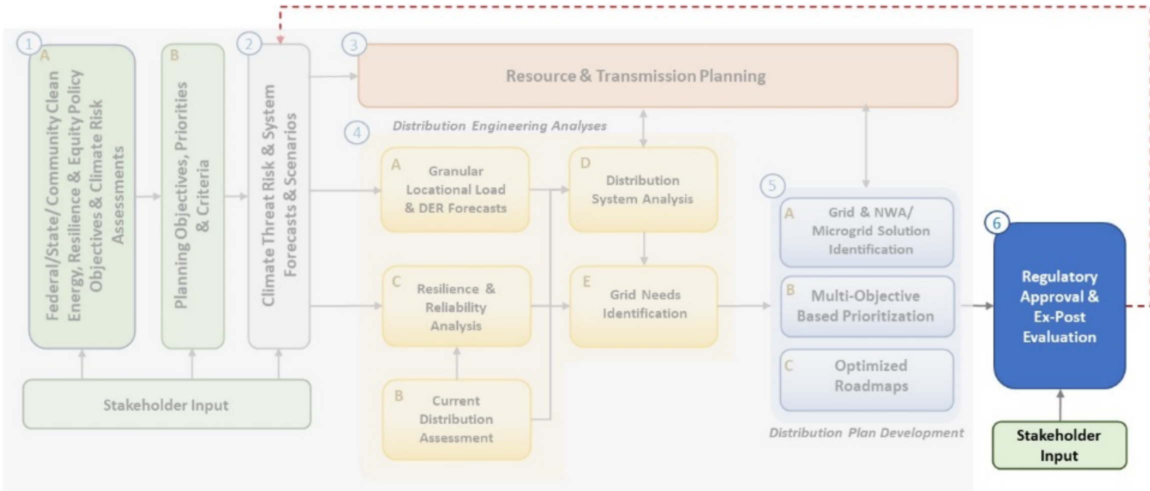


Figure 29. Combined Outage Risk Reduction from Preventative & Mitigation Measures

This type of multistage decision process provides an efficient, optimized plan based on how much of what measures are to be applied in each year within financial and other constraints. The resulting long-term and near-term plans inform applications and/or general rate case submissions for regulatory approval discussed in Step 6.

2.5 Step 6. Regulatory Approval & Ex-Post Implementation Evaluation



State regulatory review and approval of integrated distribution plans and related implementation roadmaps may involve multiple proceedings that employ one or more mechanisms for funding approval. For example, several states have instituted requirements for utilities to develop and file ongoing cyclical distribution plans with long-term implementation roadmaps including near-term action plans. These plans are often reviewed for completeness and reasonableness as well as to provide greater transparency for stakeholders. However, funding approval may involve both a general rate case for much of the proposed expenditures as well as separate grid modernization, DER, or resilience proceedings for certain expenditures.

As discussed at length in Chapter 5 of the DSPx Guidebook, state commissions have increasingly employed several cost-effectiveness methods to assess distribution plan expenditures in relation to achievement of specific objectives. Commissions' have also sought to identify the overall ratepayer impact of proposed plans and by extension set spending limits based on maximum rate increases ($/kWh) for each utility over a near-term implementation period related to distribution investments. These limits are subsequently translated into utility internal capital and operating expense budget limits that informs the 1 to 2-year utility work plans described earlier. It is important to note that most distribution investments result in net incremental capital and/or operating expenses that are not offset by utility operational savings or a reduction in the distribution expenditures in their revenue requirements. As such, customer rate impact assessment, related approved revenue requirement, and internal utility budget limits are very important criteria in development of an implementation plan.

Most distribution investments result in net incremental capital and/or operating expenses that are not offset by utility operational savings or a reduction in the distribution expenditures.

2.5.1 Ex-Post Implementation Performance Evaluation

The cycle of design to project completion can range from several months to multiple years based upon the scope and scale of the work. Distribution planning organizations are typically responsible for tracking the status of proposed and approved projects as they progress through the construction process. Upon project completion, these organizations should provide updates to asset and operational databases, such as the Geographic Information System (GIS) database, in order to document asset changes that can help facilitate the quality of system data models for use in operational tools and future engineering planning cycles. Additionally, post-project evaluation of a system's efficacy and performance is conducted annually as part of the system analysis. These annual evaluations inform the longer-term plans both in terms of progress toward longer-term objectives, remaining gaps, and lessons learned during implementation to inform future projects.

3.0 Conclusions

The process for developing an integrated distribution implementation plan is a complex undertaking given multiple objectives, variety of grid needs to address, and a wide range of potential long-term and intermediate solutions that may address more than one grid need. Substantial progress has been made over the past decade on distribution planning, including cost-effective investment frameworks, methods and processes. However, there remains considerable work to more fully develop the methods, tools and practice required to address the challenge of multi-objective decision-making for integrated distribution planning.

Therefore, the integrated resilient distribution planning process framework provided here should not be considered a prescriptive approach. Rather, it is most useful as a guide that provides a set of considerations regarding specific processes and methods that may serve the unique circumstances and objectives of individual jurisdictions and utilities. This paper intentionally did not replicate in whole part the many preceding papers discussing integrated distribution planning. As such, it is necessary to also consider the earlier work that is only summarized here regarding DER integration considerations and grid modernization.

This IRDP framework should not be considered a prescriptive approach - it is most useful as a guide.

Lastly, the extensive research by the national laboratories under way regarding multi-objective planning by the DOE Office of Electricity[51] is expected to continue to yield beneficial methods and tools for more refined approaches to multi-objective decision-planning that addresses equity, resiliency, and decarbonization. Likewise, the industry is also tackling this need as highlighted in the examples referenced. The combined efforts will very likely provide more robust methods and processes in the near future.

[51] Available at: https://energy.sandia.gov/programs/electric-grid/mod-plan/

Appendix A – IIJA Section 40108 Language for State Energy Security Plans

Under Section 40108, States are required to develop and revise State Energy Security Plans, in consultation with owners and operators of energy infrastructure, to:

1. Assess the existing circumstances in the State.
2. Propose methods to strengthen the ability of the State to:
   a. Secure the energy infrastructure of the State against all physical and cybersecurity threats,
   b. Mitigate the risk of energy supply disruptions to the State,
   c. Enhance the response to, and recovery from, energy disruptions, and
   d. Ensure that the State has reliable, secure, and resilient energy infrastructure.

In addition, a State Energy Security Plan shall:

1. Address all energy sources and regulated and unregulated energy providers.
2. Provide a state energy profile, including an assessment of energy production, transmission, distribution, and end-use.
3. Address potential hazards to each energy sector or system, including:
   a. Physical threats and vulnerabilities, and
   b. Cybersecurity threats and vulnerabilities.
4. Provide a risk assessment of energy infrastructure and cross-sector interdependencies.
5. Provide a risk mitigation approach to enhance reliability and end-use resilience.
6. Address:
   a. Multi-State and regional coordination, planning, and response, and
   b. Coordination with Indian Tribes with respect to planning and response.
7. To the extent practicable, encourage mutual assistance in cyber and physical response plans.

State Energy Security Plans are to be administered through the State Energy Offices. Efforts undertaken to support the State energy security planning process, e.g., the risk assessment activity, should inform the grid resilience planning process under Section 40101(d).

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