Distribution System Gap Analysis

Maine Public Utilities Commission

Gap Analysis for Versant Power and CMP's Distribution Systems

ELECTRIC POWER ENGINEERS

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The contents of this report are based on interviews, discussions, and documents provided by Versant and CMP, and summarized in Distribution Utility Investigation Reports. Electric Power Engineers did not audit, study, or otherwise have access to circuit models, data sources, or software systems and, subsequently, makes no claims with regards to the accuracy or veracity of the information provided and used as basis for preparing this report.

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Distribution System Gap Analysis

1 Introduction

Climate change, electrification, and the increased integration of renewable energy resources and other distributed energy resources (DERs) present major challenges to the distribution system. Addressing these challenges is necessary for utilities to continue to provide safe and reliable service at the lowest practical cost while enabling the proliferation of renewable energy resources to combat climate change. Maine has set goals to transition their electric generation portfolio to consist of only renewable energy resources by 2050, which highlights the degree of changes in the future of distribution systems.

To help Maine prepare their distribution systems for the future, Electric Power Engineers (EPE) has conducted a thorough examination of Maine's distribution systems that are maintained by Versant and CMP. EPE has documented current capabilities and practices in the Utility Investigation Reports, which provide a comprehensive knowledge of the current distribution systems' capabilities. The next step is to identify gaps and opportunities between the current capabilities of the utilities and what is needed to be ready for the future of distribution systems in Maine. To do so, it is important to realize the limitations of the utilities and the role of Efficiency Maine Trust (EMT) in the state of Maine. The EMT is the administrator for programs to improve the efficiency of energy use and reduce greenhouse gases in Maine. EMT serves all sectors and all regions of the state. Its suite of nationally recognized programs provide consumer information, discounts, rebates, loans and investments for high-efficiency, clean energy equipment and strategies to manage energy demand. EMT is a quasi-state agency governed by a Board of Trustees with oversight from the Maine Public Utilities Commission (MPUC)[1]. Current chapters of Maine Law that affect the EMT include[2]:

- **Efficiency Maine Trust Act: Maine Statute Title 35-A, Chapter 97**: In 2009, the Efficiency Maine Trust—consisting of a nine-person board of directors—was created to administer energy efficiency and alternative energy programs in Maine under the banner of Efficiency Maine.
- **Property Assessed Clean Energy: Maine Statute Title 35-A, Chapter 99**: In 2010, the legislature passed a law making it possible for a homeowner to receive a loan for home energy savings improvements, and for that loan to be transferred from the first homeowner to a subsequent purchaser of the property.
- **General Provisions – Energy Planning; Construction; Purchases: Maine Statute Title 35-A, Chapter 31, Subchapter 2**: In 2019, the legislature amended the process for planning and approving investments in the electric utilities' transmission and distribution system. The new law incorporates a formal, independent process for the consideration of Non-Wires Alternatives (NWAs). The law established an NWA Coordinator position

[1] https://www.efficiencymaine.com/about/
[2] https://www.efficiencymaine.com/about/library/policies/

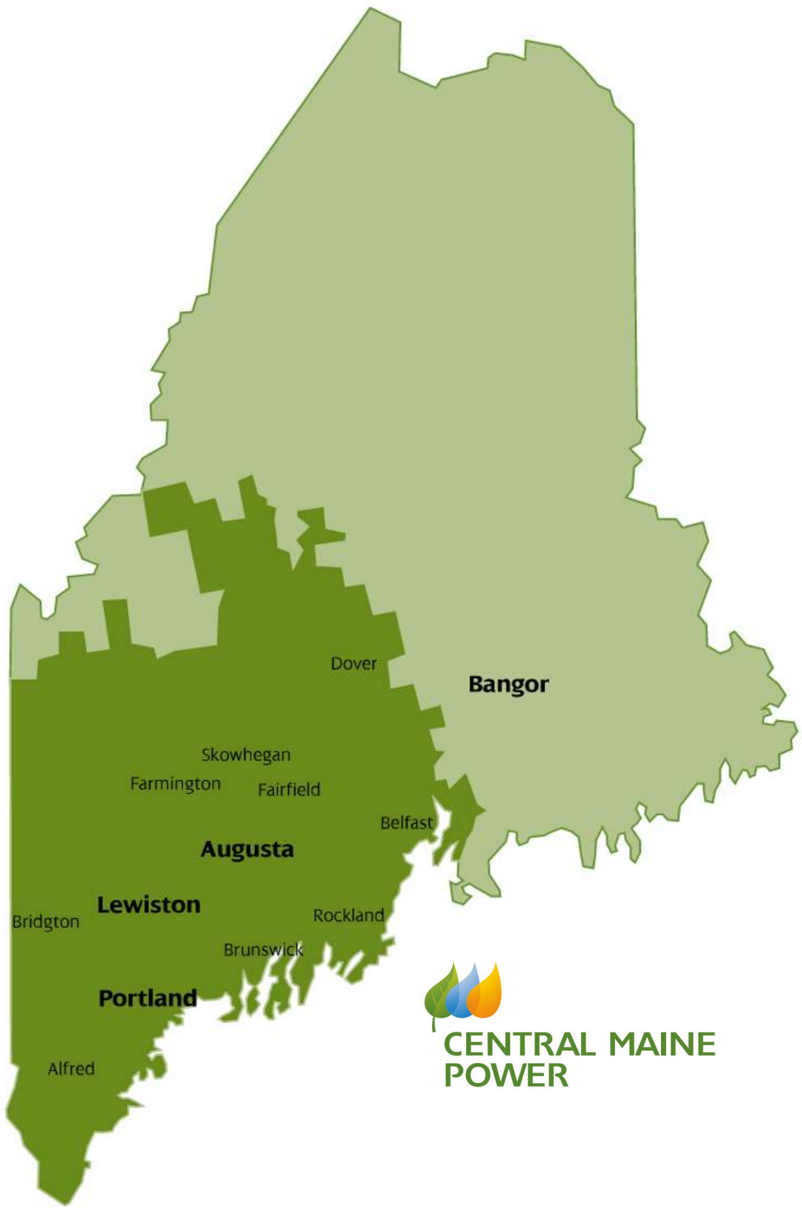
within the Office of the Public Advocate to review annual plans and individual project proposals. In these reviews, the law requires the EMT to analyze the potential for cost-effective NWA resource located on the customer's side of the meter (also called "behind the meter" or BTM) such as energy efficiency, distributed generation, load management, or energy storage. It assigns the EMT the role of developing and delivering all customer-sited NWA resources that are determined to be more cost-effective than the proposed transmission and distribution system investments.

The existence of EMT in Maine is a factor that needs to be considered when planning for the future of the distribution systems or when comparing Maine utilities to leading examples from other states. There are also size, geographical, and other factors that are important to consider when comparing Maine utilities to industry peers. These differences in regulatory structures, quantity and types of customers, land availability, system load, reliability drivers, and other key factors are necessary considerations to ensure a reasonable and efficient path forward to meet Maine's goals.

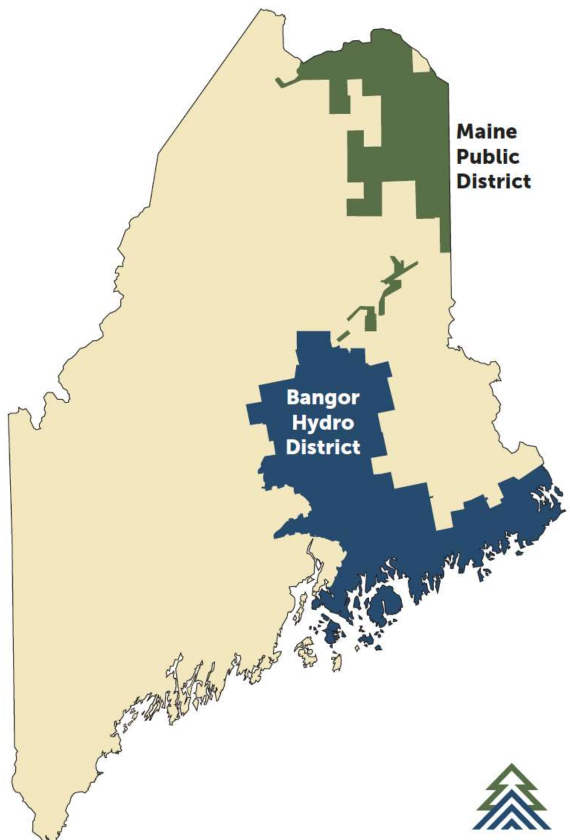
This report provides a thorough analysis of the gaps between the current state of distribution systems maintained by Versant (which consists of the Maine Public District (MPD) region in the North and Bangor Hydro District (BHD) in the South) and CMP, and the operation of distribution systems. The analysis utilizes regulatory requirements in Maine, the needs and desires of other stakeholders, and various elements of a modern grid to determine what gaps and opportunities there are. The information and analysis contained within this report are based on the Distribution Utility Investigation reports, which were previously filed within Docket 2021-00039. The organization of this report is as follows:

- Section 2 provides an executive summary of the information and analyses being provided.
- Section 3 discusses distributed energy resources (DERs) integration, control, and management. Additionally, regulatory requirements, stakeholder needs, and current best practices regarding DERs integration, control, and management are provided. Finally, a gap analysis between these requirements and the current state of distribution systems operated by both Versant and CMP is presented.
- In Section 4, a gap analysis regarding Electric Vehicles (EVs), electrification adoption modeling, and planning is provided.
- Section 5 follows the same approach for advanced distribution management system (ADMS) and distributed energy resources management (DERM) systems, as well as providing a gap analysis.
- Integrated distribution planning is another important subject which is discussed in Section 6 of this report, along with a gap analysis.
- Section 7 of this report provides concluding remarks.
- Finally, Section 8 is an appendix that summarizes both utilities' capabilities.

Service Territory



Service Territory



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2 Executive Summary

Transitioning to a modernized grid is a process, not necessarily an endpoint. As more complex technologies make their way to the distribution system, more traditional methods, assumptions, and tools become less useful, and new capabilities are required to maintain and improve cost and reliability outcomes for customers. Navigating this transition effectively means understanding the current practices, relevant stakeholders, future needs, and priorities of all involved. Electric Power Engineers (EPE) initially conducted a distribution system examination to explore the current operation of distribution systems in the State of Maine that are maintained by Versant Power (Versant) and Central Maine Power (CMP). The results of distribution system examinations were summarized in two reports and provided to Versant, CMP, and Maine Public Utility Commission (MPUC) to be used as a basis for a gap analysis between the current and desired operation of the distribution system. A summary table of both utilities' capabilities are provided in the Appendix. There are three main factors that are considered to identify potential gaps between current capabilities and those likely to be necessary to achieve Maine's goals and vision for the distribution system. These factors, summarized in Figure 1, are as follows:

1. Regulatory Requirements: These requirements are identified and provided in this report based on the most up-to-date rules and regulations set by the federal government, as well as the State of Maine. It is clear these requirements must be considered and satisfied by any and all proposed solutions.

2. Modern Grid Elements and Leading Practices: There are 6 elements (see Figure 2) defined by U.S. department of energy (DOE) that can be addressed when evaluating the performance of a distribution system. These elements are shown in the DOE's Grid Modernization Multi-Year Program Plan[3], and can be qualitatively defined as follows.
   - **Resilient:** Recovers quickly from any situation or power outage.
   - **Reliable:** Improves power quality and leads to fewer power outages.
   - **Secure:** Increases protection to the critical infrastructure.
   - **Affordable:** Maintains reasonable costs to consumers.
   - **Flexible:** Responds to the variability and uncertainty of conditions at one or more timescales, including a range of new energy resources introduced to it.
   - **Sustainable:** Facilitates the broader deployment of clean generation and efficient end-use technologies.

   Leading practices in other jurisdictions or which are being undertaken by other utilities are also important considerations for a gap analysis, as they can serve as important sources of information with regard to future needs, likely challenges, and potential solutions.

3. Stakeholder Needs: Stakeholders' needs are significant factors that should be considered when planning for the future of Maine's distribution systems. Grid Strategies conducted numerous outreach discussions and conversations with a variety of stakeholder groups and individuals and compiled the key concerns and recommendations identified within the

[3] *Grid Modernization Multi-Year Program Plan*. Department of Energy. Jan. 14, 2016. Link

Stakeholder Summary Report. These inputs were utilized in the identification of potential gaps and in the development of potential solutions.

This report provides a thorough analysis of regulatory requirements (both by the Federal Government and State of Maine), modern grid elements including current industry best practices, and stakeholder needs. Taken together, these elements identify the goals for the distribution system and are used to highlight the key areas where there are opportunities for system improvements.

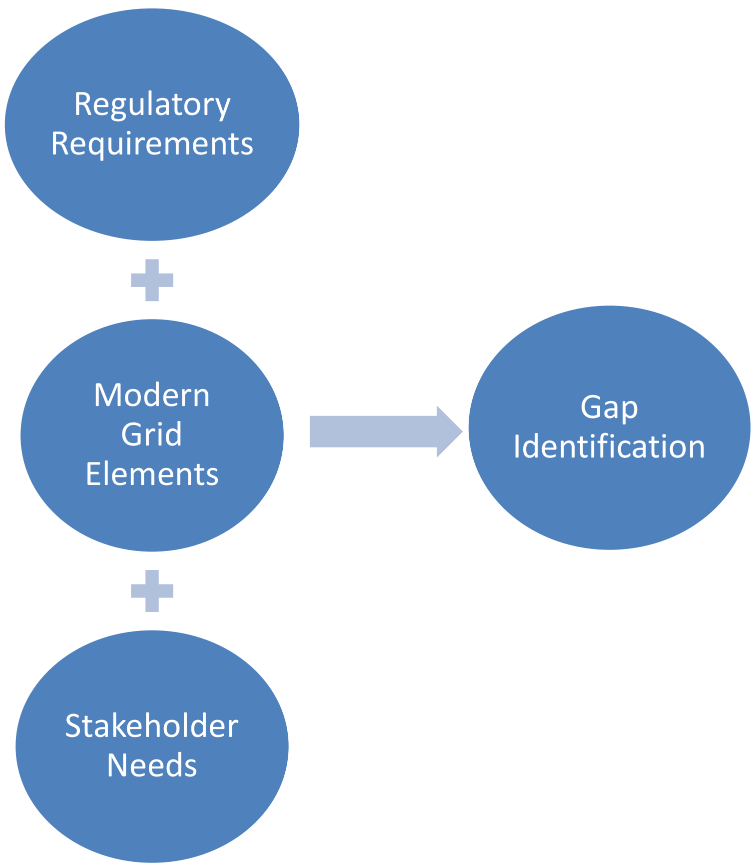

Figure 1. Three main elements used for gap analysis

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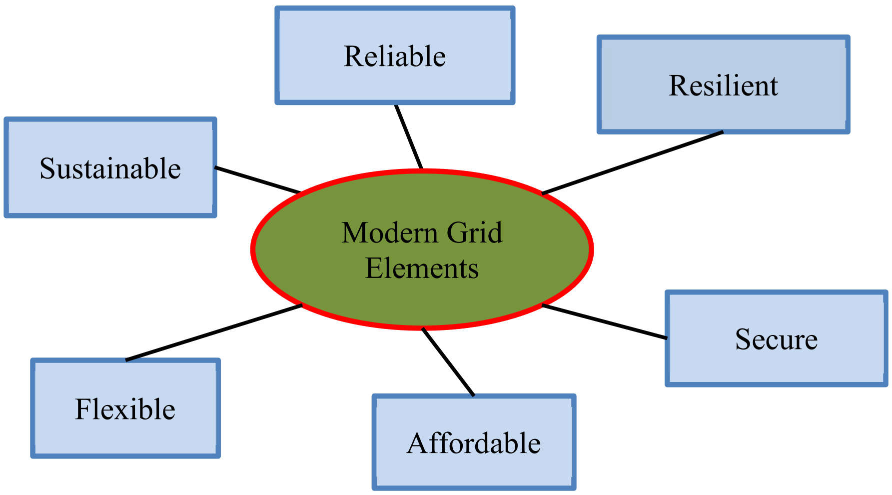

Figure 2. Modern grid elements

Two key areas of concern from various stakeholders are the reliability and resiliency of each utility's distribution system. Stakeholders would like to see utilities communicate to ratepayers what improvements are being made and how cost effective the improvements are. Increasing reliability and resiliency while keeping costs low are significant factors when customers are considering EV adoption and electrification. Additionally, high reliability leads to increased trust among customers and encourages industrial customers to connect with Maine's grid. Both CMP and Versant identified reliability initiatives that should improve customer reliability outcomes, but the criticality of the distribution system and, consequently, customer expectations, continue to increase in kind. To ensure all customers have reliable and cost-effective services, CMP and Versant need to maintain focus on proactive and comprehensive plans that target both reliability and resiliency.

Affordability and rate design were also frequently mentioned as stakeholder concerns. Rates and rate design are a more complex issue that must consider both the benefits and cost burdens on a wide variety of customer groups as well as the utilities. Since the Investigation and Gap Analysis efforts within this and previous reports are primarily utility focused, specific rate structure and recovery elements have been omitted from the Gap Analysis in favor of referencing a more consensus-driven approach exemplified by the Maine Utility/Regulatory Reform and Decarbonization Initiative (MURRDI) report. Rate and incentive design have important consequences on affordability, technology adoption, and overall economic efficiency, and should be developed, proposed, and presented in the appropriate channels as to enable all voices to be heard.

Stakeholders also repeatedly identified the need to improved communication, information availability, and consistency related to DER interconnections. Hosting Capacity was most frequently cited as a desirable improvement that would help steer developers and DER applicants to less costly, more practical areas. While neither utility currently published Hosting Capacity Maps, CMP identified a current pilot program with plans to publish maps in 2022, and Versant stated they were evaluating solutions. With that said, the data available from Hosting Capacity maps can vary significantly across different states, as well as the underlying methodology used in Hosting Capacity calculations. Continued engagement and dialog between all parties will be necessary to ensure that the information provided is useful and that the cost to generate such maps is reasonable.

Fundamentally, the purpose of this report is to utilize the regulatory requirements, modern grid elements, utility leading practices, and stakeholder feedback to identify gaps between Versant and CMP's current practices, capabilities, and results. This includes gaps of what is likely to be necessary to satisfy customers and delivery of optimal value in the face of significant changes and growing complexity related to distribution system resources, loads, technologies, data, and control capabilities. The forthcoming Roadmap Report will continue to build on the gaps identified by providing more details related to the expected costs, timelines, and underlying driving factors which will trigger the need for more advanced capabilities.

3 DER[4] Integration, Control, and Management[5]

The State of Maine has seen significant increases in DER penetration and has set goals to further increase the share of renewable energy resources for electric power generation. As a result, continuing and increasing focus on the impacts and accommodation of the adoption of DERs in distribution systems is necessary. In this section, regulatory requirements are first presented to demonstrate legislators' interest in facilitating the integration of DERs with the electric power system and, specifically, distribution systems. Then, stakeholder concerns and suggestions are provided for consideration when performing the gap analysis. Additionally, best practices by leading distribution utilities are included to help provide potential options to prepare for the future of distribution systems.

3.1 Regulatory Requirements

This section summarizes regulatory requirements regarding DER integration into the distribution system that are impactful to distribution system operation and planning, including their relevance and degree of impact.

3.1.1 MPUC Rule 407 Chapter 311 Requirements:[6]

- **Purpose:** Chapter 311 establishes requirements and standards for implementing eligible new renewable and efficient sources and thermal energy portfolio requirements in order to diversify electricity production in Maine. This rule is in pursuit of meeting legislation discussed in sections 3.1.4 and 3.1.5.
- **Summary:** This rule establishes requirements for competitive energy providers to include

[4] Distributed Energy Resources
[5] The general material of best practices section for DER interconnection are derived from NREL report that can be found at https://www.nrel.gov/docs/fy19osti/72102.pdf
[6] Chapter 311: Renewable Resource Portfolio Requirement. MPUC. Dec. 15, 2020.

a minimum percentage of renewable energy resources for electric and thermal energy generation.
- **Impact on Distribution Utilities:** This rule increases the penetration level of intermittent renewable energy resources in distribution systems in Maine.

3.1.2 MPUC Rule 407 Chapter 312 Requirements:[7]

- **Purpose:** Chapter 312 provides details of procurement of distributed generation resource attributes and other measures within Maine. This rule is in pursuit of meeting legislation discussed in sections 3.1.4 and 3.1.5.
- **Summary:** Investor-owned utilities should utilize the requirements in accordance with Chapter 312 to aggregate and purchase the output of shared DERs to sell or use the output in a manner that maximizes gained value for ratepayers.
- **Impact on Distribution Utilities:** This rule increases DERs interconnection applications in the distribution system.

3.1.3 MPUC Rule 407 Chapter 324 Requirements:[8]

- **Purpose:** Chapter 324 establishes procedures for small generator interconnections to utility T&D systems.
- **Summary:** This rule defines various DERs levels for interconnection to utility systems, cost responsibilities, standard forms, standards, pre-application report, technical screening criteria, cost-sharing, feasibility study, impact study, and inspection and witness testing.
- **Impact on Distribution Utilities:** This rule establishes a framework for DER interconnection criteria that need to be applied by distribution utilities.

3.1.4 Public Law No. 1494 Requirements:[9]

- **Purpose:** PL 1494 reforms Maine's renewable portfolio standard to encourage and diversify renewable energy generation.
- **Summary:** This act requires competitive electricity providers in Maine to demonstrate in a manner satisfactory to the commission that the percentage of their portfolio of supply sources for retail electricity sales accounted for by renewable capacity resources is 50% by 2030 and 100% by 2050.
- **Impact on Distribution Utilities:** This act increases the penetration level of distributed renewable energy resources in distribution systems in Maine.

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[7] Chapter 312: Distributed Generation Procurement. MPUC. Dec. 24, 2019.
[8] Chapter 324: Small Generator Interconnection Procedures. MPUC. Mar. 15, 2020.
[9] LD No. 1494 An Act to Reform Maine's Renewable Portfolio Standard. 129th Maine Legislature. Apr. 4, 2019.

3.1.5 Public Law No. 1711 Requirements:[10]

- **Purpose:** PL 1711 promotes solar energy projects and distributed generation resources in Maine through amendments to NEB.
- **Summary:** This act amends and enacts provisions regarding NEB and the Maine Solar Energy Act to support the integration of solar by:
    - Increasing the maximum capacity of eligible facilities from 660kW to less than 5MW.
    - Removing limits on the number of meters or accounts that can be associated with an eligible facility.
    - Replacing an ownership requirement with a "financial interest" requirement, which includes a purchase power arrangement; and
    - Adopting "commercial and institutional" NEB.
- **Impact on Distribution Utilities:** This act promotes solar energy projects and NEB programs and will cause an increase in distributed solar and specifically NEB-enabled solar energy.

3.1.6 FERC Order No. 2222:[11]

- **Purpose:** FERC 2222 establishes a foundation for the future integration of DERs into electric power systems and wholesale electricity markets by establishing requirements to modify ISO/RTO tariffs.
- **Summary:** ISO-NE, the primary RTO for Maine, will file their plan for compliance on February 2, 2022. FERC requires ISOs/RTOs to establish their plan of integrating DERs into the wholesale market and develop a comprehensive and non-discriminatory process for timely review of the individual DERs by a distribution utility that comprises a DER aggregation.
- **Impact on Distribution Utilities:** Once requirements are established, utilities will see an increase in DERs interconnection applications, resulting in the potential for:
    - More frequent dispatch of DERs (EVs, battery storage, workplace charging, etc.).
    - Increase in residential demand response and energy efficiency (Smart thermostats, water heaters, etc.).
    - Increase in residential behind-the-meter resources (solar and storage, EV charging, etc.).
    - Increase in front-of-the-meter distribution-connected resources (grid-scale battery storage, etc.).

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[10] LD No. 1711 An Act to Promote Solar Energy Projects and Distributed Generation Resources in Maine. 129th Maine Legislature. May 9, 2019.

[11] Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators. FERC Order No. 2222. Sep. 17, 2020.

3.2 Stakeholders Needs

This section provides one or a group of involved stakeholders' concerns, ideas, opinions, and suggestions which are taken from "Maine DER Roadmap- Stakeholder Feedback" report directly and summarized in this report. While this process reached a diverse group of stakeholders, it does not reflect all stakeholders engaged in these issues. The goal of this work is to capture the broad concerns and diverse visions among energy businesses, elected officials, system operators, and advocates in an accessible, clear and anonymous summary. No attempts were made to verify any of the factual assertions in the stakeholder comments, except where footnoted. No statement has unanimous agreement from stakeholders – there is a wide diversity of views on the sources, severity and solutions to the challenges of DER integration, and no statement in this report should be attributed to any specific stakeholder. Even when "many stakeholders" raise a concern or support a position, this should not be read to suggest that even a majority of stakeholders hold such a belief.

- **Stakeholders Concerns**

  - Stakeholders raised concerns that Maine ratepayers were hearing more about the costs than the benefits of electrification and the transition to clean energy.
  - Slow timelines and difficult approval processes for DER integration were similarly seen as having a cooling effect on economic development.
  - Entities working in the electricity industry were highly concerned about a lack of access to data on grid utilization and hosting capacity and the impact of existing distributed resources.
  - Some ratepayers have noted concern or surprise about where DERs are being built. Including ratepayers to ensure optimal location is important.
  - Stakeholders do not believe that utilities currently use mapping, modeling, or management tools to achieve widespread DER integration. Utility data that is available can be inaccurate.
  - Utilities and DER developers do not have access to the same system data or maps and should be in closer coordination. There is concern that data is excessively siloed even within the utility, such that departments which interface with DER developers are not able to share information about where hosting capacity exists, where existing distributed energy assets are located, and other important contexts.
  - DERs, including rooftop solar and home batteries, do not always help with reliability when there is a broader system outage. Stakeholders would like to see more of this capability.
  - The number of successfully integrated DER installations is low compared to the number of applications, and new processes and investments are needed to support the level of interest.
  - DER developers and Maine utilities are working together, but their work proceeds on different timescales, and it is difficult to reconcile the decentralized and centralized planning of DERs and wires, respectively. Utilities are not able to move as fast as DER developers hope, largely because of the planning and upgrade timelines.

- Renewable energy developers do not know where the grid has hosting capacity to accommodate new renewable energy. This leads to interconnection requests piling up in locations that are infeasible.
- Developers are not able to get clear evaluations of the cost of interconnection in a timely manner and have faced changes in cost estimates that derail projects. Stakeholders acknowledged that the distribution grid would need significant investment to accommodate DERs at the pace and scale of Maine's DER legislation.
- Stakeholders suggested that utilities did not have proper incentives to facilitate DER interconnection, and that a lack of system knowledge and awareness was restricting quicker action.
- Peak electricity demand is very low for some circuits, which is a significant obstacle for integrating new variable generation on short timescales. Northern Maine is expecting DER generation to at least double in the near term - a significant but manageable change, though the region is not expecting significant load growth in the absence of further public policy supporting electrification.
- Some stakeholders are skeptical that focusing on DERs is the right solution for Maine when utility-scale renewables may cost less. They are interested in seeing more data about the various approaches.
- Maine's DER installations have unique accounting problems. Renewable Energy Credits generated by DERs in Maine can be sold by marketers in Massachusetts, thereby removing their worth in Maine's sustainability goals while potentially costing ratepayers in grid upgrades. There is also concern that community-owned DERs will be sited far from the load that invested in them, increasing local costs while allegedly serving ratepayers far away.
- Maine has a higher-than-average share of emissions coming from transportation, so increasing consumer enthusiasm (and price accessibility) for zero-emission transportation is critical.
- Although utilities have sustainability goals and adopt electric vehicles, Maine's IOUs[12] generally do not have an obvious incentive to integrate the new generation well.

- **Stakeholders Suggestions**

- More information about where new DERs should be sited will be key to achieving Maine's DER goals with the highest consumer value on circuits that have hosting capacity or need generation to defer upgrades.
- Transparency in DER siting is needed by developers and would be welcomed by ratepayers.
- Stakeholders saw value in public investment in efficiency, demand response, and other behind-the-meter interventions that Efficiency Maine Trust (EMT) can support. They contrasted the investment in these measures to the renewable energy subsidies, suggesting the two should be equally valued in Maine's energy transition strategy.
- Developers and customers would like to see faster and more definitive action from the utilities on their DER projects.

[12] Investor-owned utilities

- More data about areas where new resources can interconnect would be helpful to integrate more DERs.
- Successful DER integration will require more visibility into each circuit and more active resource management. Stakeholders suggested that simply overbuilding infrastructure on a circuit is not the best choice, even with substantial uncertainty about future needs.
- Different market rules outside of the ISO-NE region will require a slightly different approach to Maine's DER goals. Overall, in Maine, the peak load is growing.
- Making DERs dispatchable through aggregation, price signals, or automation will help with integration in the longer term. Stakeholders see decentralized control as an approach that will leave room for more innovation and faster integration.
- System operators are working on implementation plans for FERC Order 2222, which will give DER aggregators access to the wholesale markets.
- High costs to individual customers looking to integrate DERs or electric vehicles on their properties undermine sustainability goals. Utilities must find more affordable ways to integrate these new technologies.

3.3 Best Practices and Emerging Strategies

This section addresses current leading or innovative practices and recommendations in one of the most evolving areas within distribution systems, i.e., DER integration with the electric distribution system. The importance of DERs integration with distribution systems is clear as State, and Federal governments have goals of achieving high penetration levels of DERs and, specifically, renewable DERs. Therefore, developing and adopting efficient strategies and plans for best-utilizing potentials of DERs for benefitting the distribution system operation, moving towards a modern grid that is more affordable, flexible, sustainable, reliable, resilient, and secure, and meeting the goals and requirements of stakeholders and the people of Maine is necessary.

In this section, general requirements and practices for efficient integration, control, and management of DERs in distribution systems based on a report by NREL[13] are discussed in detail, and also, some utilities which are currently implementing state-of-the-art practices are provided as examples. Many of these modern practices are still in the development stage and being tested as pilot projects; however, they provide a good understanding of emerging new strategies with significant promise.

3.3.1 Interconnection Application Procedures[14]

Due to the expected high volume of applications from DER developers for interconnection to the distribution system, an efficient and automated application process can facilitate DER interconnection applications handling and review, which would otherwise cause delays and inefficiencies in the process.
A central information webpage is used by some utilities with the following key elements to facilitate interactions and data collection from DER developers.

[13] https://www.nrel.gov/docs/fy19osti/72102.pdf
[14] https://www.nrel.gov/docs/fy19osti/72102.pdf

- **Application Forms:** The website should act as a guide for the users to find appropriate forms required by the utility.
- **Application Checklist:** A customer-facing document that provides all the details of the process, including the timeline for major milestones, requirements, fees, any pre-application reports, construction of upgrades, and meter installations.
- **Contact Information:** Single points of contact on both the utility and developer sides.
- **Reference Materials:** Resources such as example application documents (e.g., one-line drawings) or instructional videos along with frequently asked questions (FAQs) can help in educating developers and reduce the number of questions utility staff must respond to.
- **Dispute-Resolution Processes:** Providing a clear pathway for resolving disputes in a timely manner.
- **Pre-application Reports:** Providing technical information to the developers to help them get a good understanding of the point of interconnection and associated potential interconnection limitations. FERC's[15] SGIP[16] can be used as a template for pre-application reports. As an example, in Minnesota, Xcel Energy provides example drawings that customers can use as references.
- **Application Clarity:** Clear information and data request in the applications.
- **Workflow Efficiency:** Removing redundant requests for information.
- **Signatures and Payments:** Allowing online payment options and electronic signatures instead of cash/check or wet signatures can help to avoid delays and difficulties.
- **Communication:** Designating a single point of contact or team to handle interconnection-related requests and questions.
- **Application Tracking:** A clear way of tracking DER interconnection applications by DER developers once they are submitted is necessary. As an example, California Rule 21 requires investor-owned utilities (IOUs) to post interconnection queue information publicly for certain projects.
- **Automation and Integration:** Tasks such as document generation (e.g., meter exchange orders), workflow reminders, and application status updates can all be automated to minimize the resources needed to handle them. In addition, integrating interconnection application data with mapping or analysis tools also can enhance efficiency and reduce labor.
- **Implementing Considerations:** There are a few factors that need to be taken into account before implementing any improvements in the application management procedures listed below.
  - Regulation: Utilities may require approval from regulators to make any changes, or regulators may require specific procedures. For instance, New York established a requirement for all IOUs to deploy an online application system.
  - Resource Availability: Considering the availability of staff or operational funds.
  - Interconnection Activity: Automated application systems may even be unnecessary if the current and expected interconnection requests/applications are very low.
  - Utilities Operational Preferences also play an important role.

[15] Federal Energy Regulatory Commission
[16] Small Generator Interconnection Procedures

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3.3.2 Technical Screens for DER Interconnection[17]

Technical screening of DER systems that intend to interconnect to the distribution system is vital for ensuring a reliable, safe, and cost-effective interconnection. When a complete interconnection request is submitted by a DER developer, technical screens can be used to approve or disapprove the application. Moreover, if an application does not pass the initial screening, many states are allowing a supplementary review to determine a detailed impact study.

Many states have adopted FERC SGIP procedures which involve a series of 10 initial review screens; if any of these technical screens are failed, the DER application may be required to go through supplemental technical screens. FERC SGIP also provides a Supplemental Review process for the DERs that do not pass the 10 Fast Track screens as they are very conservative. In the state of Maine, in MPUC's Rule 407 Chapter 324, Fast Track technical screens are provided for DERs of different levels (Level 1, Level 2, Level 3, and Level 4) which utilities are required to utilize when DER interconnection applications are submitted.

In the state of Maine, it was noted by the utilities that due to the high volume/size of DER interconnection applications, most applications fail these screens and need to go through an impact study to determine the costs and required upgrades to the distribution system. CMP currently has 17 Level 4 installations of solar and energy storage interconnected which total 64.76 MW of nameplate capacity. There are an additional 487 Level 4 installation requests totaling 1,871 MW in queue.[18] CMP currently has more than 5,000 Level 1 and Level 2 systems interconnected, which total more than 73 MW. CMP states that the cumulative capacity of currently active interconnection applications is over 2,000 megawatts, which is more than CMP's current peak demand of 1,707 megawatts[19]. Versant is also experiencing significant DER application requests, namely 147 projects are queued at Level 4 which are roughly 530 MW and 150% of Versant's peak load. These challenges with the efficiency and inability to effectively use screens due to high penetrations are not unique to Maine. In California, it has been observed that[20] DER interconnection delays have increased from about 4 months to 2 years since 2014 as a result of grid upgrade requirements mainly due to reverse power flow.

In addition to Fast Track screens and Supplemental Review discussed above, depending on system conditions and the characteristics of DERs applying for interconnection, Power Flow and Hosting Capacity analyses can be used to determine interconnection impacts more accurately. Pepco Holdings Inc. (PHI), which is a power delivery company headquartered in Washington D.C., is one utility that has begun using power flow modeling for PV[21] systems evaluation in collaboration with Electrical Distribution Design (EDD). The automated process they use for distributed PV (DPV) applications screening is summarized in Figure 3. This approach requires significant data and modeling capabilities as well as integration between different utility systems.

[17] https://www.nrel.gov/docs/fy19osti/72102.pdf
[18] The details of these installations were provided to EPE and marked as confidential.
[19] Docket No. 2021-00082
[20] https://www.calcomenergy.com/distributed-energy-resource-saturation/
[21] Photovoltaic

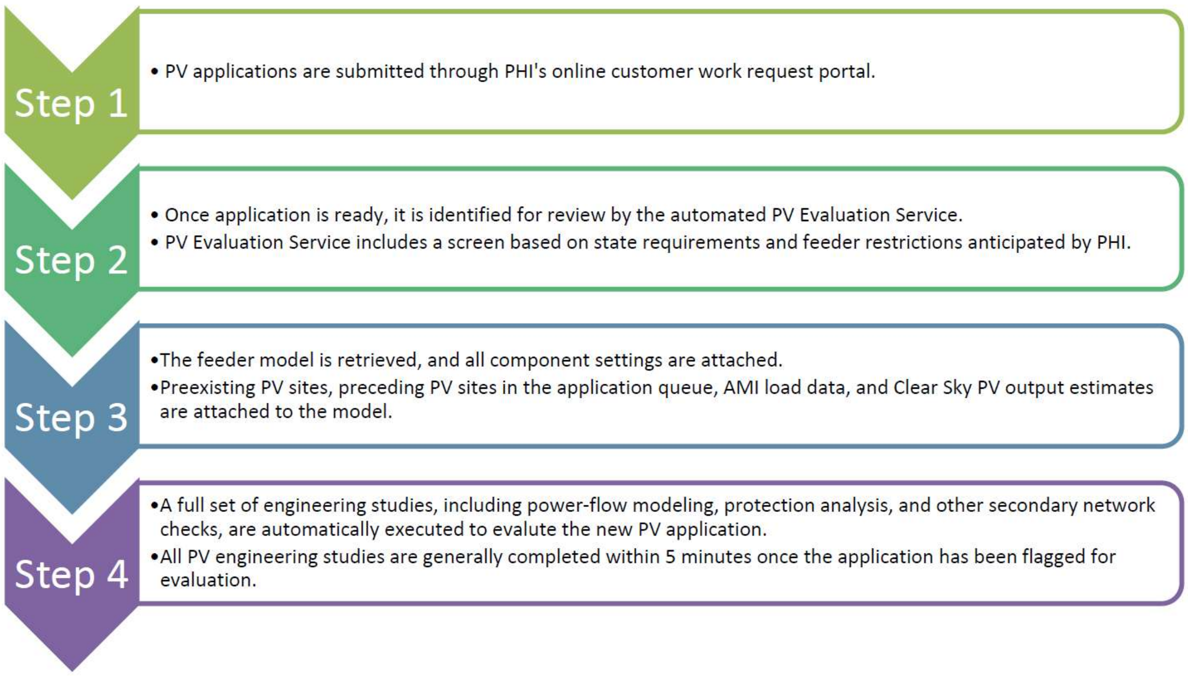

Figure 3. PHI process for automated DPV screening using power flow modeling[22]

As another example[23], utilities in California publish integration capacity analysis (ICA)[24] maps which are designed to help contractors and developers find information on potential project sites for DERs. ICA is a complex modeling study that uses detailed information about the electric distribution system, which includes items such as physical infrastructure, load performance, and existing and queued generators. The analysis simulates the ability of individual distribution line sections to accommodate additional DERs without potentially causing issues that would impact customer reliability and power quality or require system modifications to resolve. The ICA maps provide two types of information: feeder level and line section level. The feeder level displays information for entire feeders, including voltage, generation, and customer count, to help users understand the grid at a macro level. The line section level displays ICA results for line sections or segments of a feeder. An example of ICA maps for a line section is shown in Figure 4, and Figure 5 shows the hourly load profiles for low and high load periods. This map shows a color-coded existing capacity (with and without DER operational flexibility), and detailed information for the specific identified point, as well as circuit load profiles, at the Paul Sweet substation in Live Oak, California,[25] maintained by PG&E.

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[22] Bank, J. 2017. "DEW-ISM Implementation at PEPCO: A Model and Data Driven Approach to Automating PV Interconnection Studies." Presented at IEEE PES, July 20, 2017. http://www.edd-us.com/wp-content/uploads/2017/07/IEEE-PES-GM-2017-Pres-jbank.pdf.

[23] https://www.pge.com/b2b/distribution-resource-planning/downloads/integration-capacity/PGE_ICA_Map_User_Guide.pdf

[24] ICA is the hosting capacity used by utilities in California.

[25] https://www.solarpowerworldonline.com/2019/01/california-utilities-release-maps-showing-where-solar-generation-projects-can-easily-be-developed/

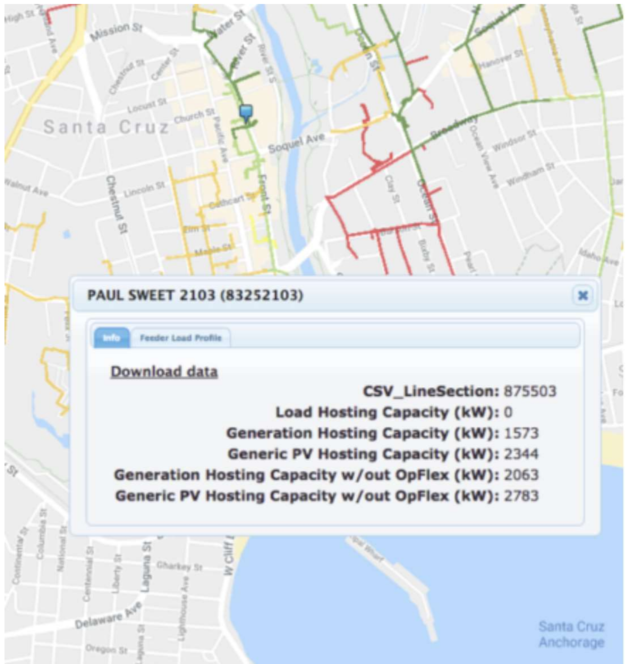

Figure 4. An example of ICA maps in Live Oak, California

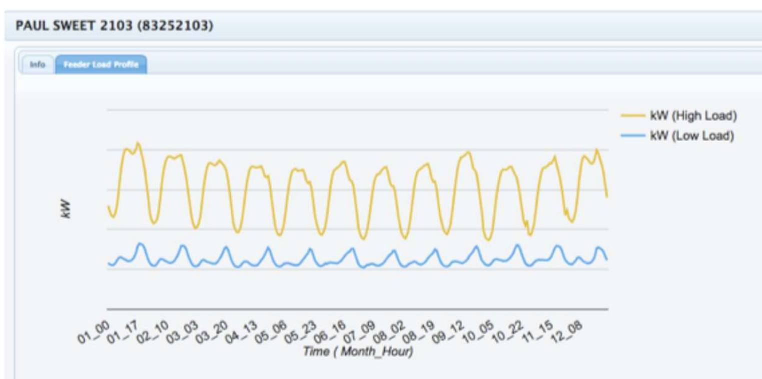

Figure 5. Load profiles for ICA map example in Live Oak, California

3.3.3 Advanced Inverters

Many DER systems use inverters to deliver AC[26] power to the grid at 60 Hz frequency and use inverters' features to provide support to the grid through reactive power control, active power control, remote connect/disconnect, etc. When the solar PV industry first started being introduced to electric distribution systems, utilities mandated that all distributed generation comply with extremely narrow windows of operation (if the voltage or frequency stayed outside narrow bounds, inverters were forced to trip offline). DERs were allowed to reconnect to the system 5 minutes after the system went back to normal. In addition, the original IEEE 1547 standard prohibited inverters from helping regulate voltage and mandated them to operate at unity power factor.

[26] Alternating current

Inverter-based DERs were not even allowed to modify their output and help stabilize and support the grid.

However, today DERs like solar PV and wind are a substantial part of the energy mix in the U.S. Hence, utilities can no longer have DERs trip offline in the event of a grid disturbance and need all generations to stay online as much as possible to ride through the disturbance and help clear the fault. Also, the inverter-based DERs can provide additional grid supporting functions to help further increase the hosting capacity in a region. To address these critical needs, states and utilities have been changing their grid interconnection standards to allow and even require grid-supporting functions. As a first step, IEEE 1547 was amended in 2014 to remove restrictions against inverters actively participating in voltage regulation and to allow voltage control and disturbance ride-through. At the same time, utilities, developers, manufacturers, and other industry stakeholders worked collaboratively to define a range of new “Smart Inverter” functions which inverters can provide to support the grid and allow increased percentages of solar, followed by a new expansion of UL 1741 to test and certify these new functions under UL 1741 SA.

The 2014 UL 1741 SA standard served as an effective bridge between the initial 1547-2003 standard and the 1547-2018 updated standard, which solidifies and expands on many of the elements within UL 1741 SA, including grid support functions, communications, and interoperability, among others. IEEE 1547-2018 compliant hardware will be certified to UL 1741 SB and is expected to become commercially available in 2022. Advanced inverters can be either controlled by customers or, where applicable, the utility to provide grid support functionality. Figure 6 shows two categories of functionalities that can be activated on advanced inverters.

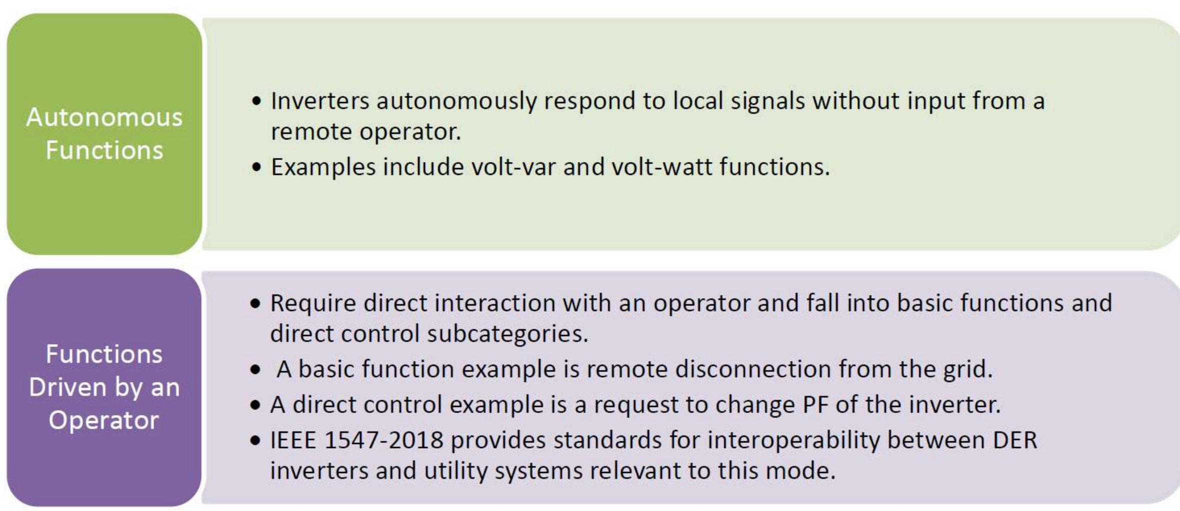

Figure 6. Smart inverter functional categories

Constant PF[27] mode, voltage and reactive power control, and voltage and active power control are the three most commonly used advanced inverter voltage regulation functions. Voltage and active power control are typically only used as a backup function for temporary abnormal conditions,

[27] Power factor

such as when the voltage is outside of Range B voltage limit defined by ANSI[28]. Below is a brief description of different control schemes used for advanced inverters.

- **Constant PF Mode:** In this mode, the PF of the DER is kept constant and is not typically lower than 0.9. Constant PF mode with a PF of 1 is the default mode in standards and typical interconnection procedures. The disadvantage of this mode is that reactive power is provided (at times unnecessarily lowering active power output compared to unity PF) even when the voltage is in the normal range.
- **Voltage and Reactive Power Control (Volt-Var Control):** This control mode is used when situational changes to reactive power as a function of voltage is desired. Figure 7 shows a typical Volt-Var curve used for the control of output reactive power by monitoring the voltage at the PCC[29] or the point of interest. For most applications, the Volt-Var curve is predefined, and the advanced inverter operates autonomously. In Figure 7, V_{ref} is the reference voltage considered "normal" or desirable which can be set based on the location of the inverter on the circuit and the application[30]. Moreover, some commercial ADMS[31] products can compute optimal V_{ref} for the smart inverters to adjust their power output accordingly.

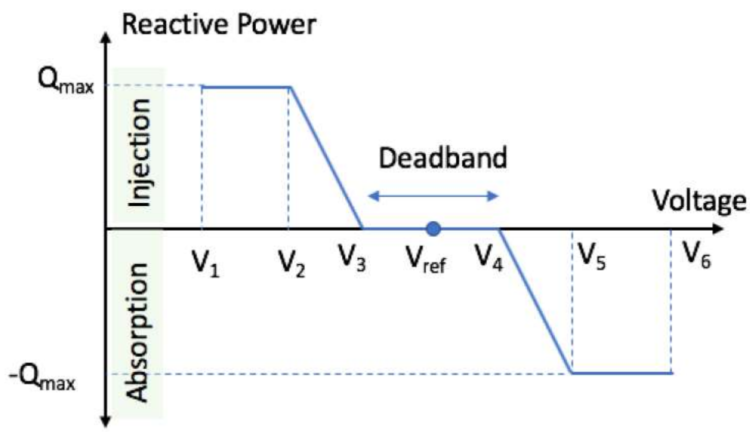

Figure 7. Example of a Volt-Var curve[32]

The one possible disadvantage of Volt-Var control is the potential for control interactions or oscillatory behavior where not appropriately addressed in the planning and design phases. The remedy for this issue is by setting an appropriately wide dead-band or evaluating feeder voltage control schemes for potential negative impacts.

- **Voltage and Active Power Control (Volt-Watt Control):** As shown in Figure 8, in this control mode, active power is controlled as a function of voltage in an autonomous way. Volt-Watt control is typically used in combination with other control modes as an

[28] American National Standards Institute (Range B voltage based on this standard is plus 6% and minus 13% of nominal voltage)
[29] Point of common coupling
[30] For example, implementation of CVR which lowers the distribution system voltage to reduce energy consumption may use a lower V_{ref}, e.g., 0.96 p.u.
[31] Advanced Distribution Management System
[32] https://www.nrel.gov/docs/fy19osti/72102.pdf

"emergency backup"; for instance, Volt-Var or constant PF is used unless the voltage moves into an abnormal range, in which case Volt-Watt control is activated. In the IEEE 1547-2018 standard, the lowest allowable threshold for the use of volt-watt is the threshold between ANSI Range A and ANSI Range B, with the default setting at 1.06 p.u. This approach is used to avoid excessive or unnecessary real power curtailment from the DER.

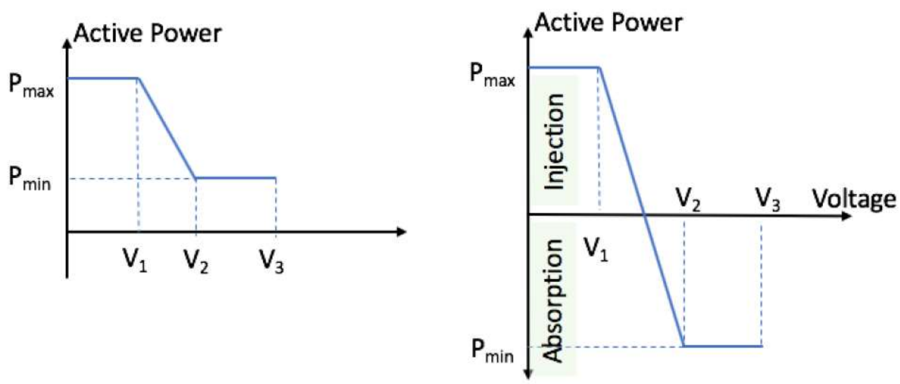

Figure 8. Two examples of Volt-Watt controls: Generating active power only (left), both generating and absorbing active power (right)[19]

- **Active Power-Reactive Power Mode:** In this mode, the reactive output power is controlled as a function of output active power based on a piecewise linear curve shown in Figure 9. This method is used to keep PF within the desired range while not injecting/absorbing substantial reactive power. However, it can be challenging to come up with an effective control curve to adjust the voltage since the inverter is not responding to the voltage, which is why this control mode is rarely used in practice.

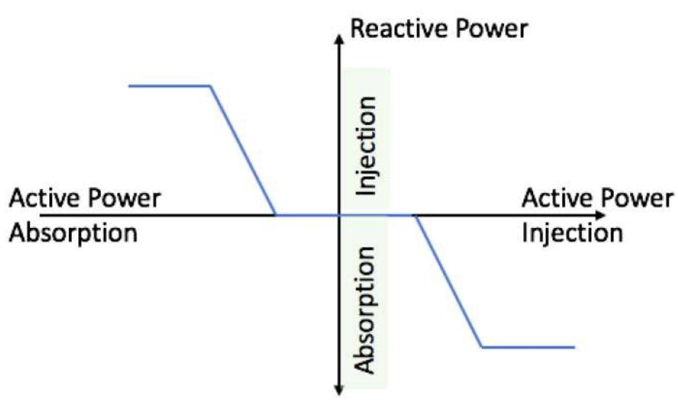

Figure 9. An example of active power-reactive power control

- **Constant Reactive Power Mode:** The issue with this control scheme is that VARs are provided (injection or absorption) even if the voltage is in the normal range.

Overarching Notes: In selecting the proper control scheme and setting parameters, some learned lessons from real-world implementation should be taken into account since some parameter settings can cause undesirable behavior like hunting (unwanted oscillations of the inverters or voltage regulating equipment). Examples are the use of very steep slopes for Volt-Var or Volt-Watt control curves, extremely fast response times, or intentional delays in the control system. Also, when using Volt-Var combined with Volt-Watt control with "active power priority mode[33]," instabilities may happen. IEEE 1547-2018 defines reasonably slow default response times and eliminates "active power priority mode."

3.3.4 IEEE 1547 Standard (2003-2018)

The main standard in the United States for interconnection of DERs has been IEEE 1547 family first published in 2003, then updated to IEEE 1547a, and recently updated to its newest version, i.e., IEEE 1547-2018. IEEE 1547 first applied only to the PCC or local DER interface, with the revised version covering other important system criteria such as the point of connection (PoC), which may be far away from the PCC.

- **Changes in IEEE 1547-2018:** The 2018 version of the IEEE 1547 family of standards has some changes as compared to the original 2003 version, which are summarized below.
  - DER Size Limitations

  The 10-MW cap on the standard's applicability is eliminated, and as a result, the standard now covers any kind and size of generation connected to the distribution system, and any reference to power is in Volt-Amps.
  - Reactive Power Support

  While meeting all jurisdictional rules, the new version requires DERs to have leading and lagging PF capability and several reactive control functionalities in coordination with the utility to support the local voltage.
  - Ride-through Requirements

  Within IEEE 1547-2018 standard, DERs depending on the technology and location, are required to be able to ride through grid disturbances (voltage and frequency) to support the grid and provide stability and reliability to the grid.
  - Bulk System Support

  This requirement wants DERs to be able to provide primary frequency-response functionality to help mitigate frequency disturbances on the bulk power system.
  - Protection Coordination

  In the new version, it is clarified how DERs need to be coordinated with feeder recloser to prevent reclosing into unintentional island conditions or phase differences.
  - Power Quality

  Power quality requirements in this version are updated to include details on power electronic technology (smart inverters).
  - Interoperability Requirements

  These requirements will allow DERs to be integrated into distribution systems with automated controls and communications capabilities.
  - Testing and Modeling

  Testing will allow for modeling programs to model DERs with improved accuracy of short-circuit current characteristics of inverters.

[33] Meaning active power output is prioritized over reactive power.

- Secondary Network Distribution Systems

In Clause 9 of the standard, DERs capability to interconnect to secondary network distribution systems is discussed in detail.

- Function Prioritization

This part of the standard gives DERs the capability to prioritize various DER functions.

- Open Phases

Capability to detect open-phase conditions for DERs.

- Default and Adjustability

This new update provides guidance on DER control and trip settings with both default settings and a wide range of adjustability for many technologies.

- Communication Standards

A standardized and non-proprietary design is recommended for communications interfaces.

- Anti-island Prevention

Some improvements are observed in anti-islanding detection, with the detection and 2-second trip time remaining the same.

3.3.5 Strategies for Mitigating the Impacts of DERs on Distribution Systems

Integration of DERs into distribution systems may cause issues with voltage, power quality, and protection coordination depending on DER technology, DER control scheme, interconnection location, and characteristics of the distribution system. Table 1 shows typical solutions used today to mitigate the effects of DERs on distribution systems. In addition to solutions outlined in Table 1, limiting the size of DERs can be an alternative solution.

It will be a helpful practice for the utility companies to provide DER developers with distribution system information such as ground fault protection, on-load tap changer, thermal ratings of conductors, and the distance to three-phase network to guide them into locations where thermal violations and substation upgrades are less likely to occur.

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Table 1. Typical solutions used today for mitigating impacts of DERs on distribution systems[34]

Mitigation Solution	Applicable Violations	Key Considerations and Notes
Use alternative PF set points for the DER, for example, non-unity PF or advanced inverter functions for var and watt control	• High or low voltage • Voltage flicker at PCC	• Low to no cost if set at install. • Ability to mitigate voltage problems depends on the fraction of advanced inverters on the system. Retrofits of old inverters are typically prohibitively expensive. • At high penetrations, advanced inverters may need to be used in concert with other voltage-regulation solutions to fully mitigate DER impacts. • Legal and commercial constraints should be considered. • Utility ownership and/or control of advanced inverters is possible, being piloted.
Modify capacitor and/or voltage-regulator controls	• Reverse power flow • High or low voltage • Voltage flicker at the device • Excessive device movement	• Bidirectional or co-generation mode for desired operation with reverse power flow. • Modifying device bandwidth may help with voltage flicker.
Move voltage-regulating devices	• Voltage flicker at the device • High or low voltage	• Need to balance high- and low-voltage conditions.
Install new voltage regulators	• High or low voltage	• If adding new regulators, include bidirectional functionality.
Modify load tap changer (LTC) tap set point	• High or low voltage • Excessive device movement	• Need to balance high- and low-voltage conditions.
Install LTC at the substation	• High or low voltage	
Direct transfer trip (DTT)	• Anti-islanding • Voltage supervisory reclosing relaying	• UL1741 inverters pass anti-islanding tests, but interaction between inverters may not be tested. • DTT is required by utilities under certain circumstances, but not universally.
Reconductoring	• Thermal overload • Voltage flicker	
Upgrade protection coordination schemes	• Protection	
Move protective devices	• Protection	

[34] https://www.nrel.gov/docs/fy19osti/72102.pdf

3.3.5.1 Emerging Mitigation Strategies

- *Energy Storage:* Today, there are a variety of energy storage methods and technologies at various stages of maturity, the most common of which is battery energy storage. Batteries can be used to increase the hosting capacity in certain circumstances and operating modes. New York suggests deploying batteries at flexible interconnection sites to decrease curtailment risk[35]. Hawaiian Electric Company (HECO) has found that using behind-the-meter (BTM) storage to avoid export from PV systems can significantly decrease the cost of distribution system upgrades as penetration levels of PV systems grow, although this incurs costs to the customer/developer. In fact, if batteries are used to eliminate export through the revenue meter, this alleviates most common distribution violations and negates the need for upgrades but can also significantly reduce load and, therefore, impact utility planning. PG&E outlines some of its experience using batteries for transmission and distribution cost reduction as part of its demonstration project report[36]. Xcel Energy has a pilot on the use of storage deployed both on the distribution feeder and BTM for voltage regulation and peak shaving[37]. Arizona Public Service (APS) has a similar pilot with storage deployed at the neighborhood level[38]. Results and best practices from these pilots are still emerging.

  In addition to batteries, there is other technologies to be used as energy storage; some of these technologies are briefly summarized below.

  - Thermal Energy Storage (TES): The most widely used form of TES is sensible heat storage in which a liquid or solid storage medium—such as water, molten salts, sand, or rocks—is heated or cooled to store energy. Sensible heat storage is widely utilized in concentrated solar power applications namely "Crescent Dunes Solar Energy Project" in Tonopah, Nevada. Using this type of technology, excess power from renewable resources during peak power generation and light power load can be utilized to generate and store heat in a liquid or solid storage medium -in the form of molten salt or other materials - and can be used during peak power load to generate steam to drive a turbine to produce electricity.

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[35] REV Connect. 2018. "Lessons from REV Demos in New York's Energy System." From REV Connect Webinar Series, January 17, 2018. https://nyrevconnect.com/wp-content/uploads/2018/01/Webinar2_Demo-Principles-v6-01-17-18.pdf.

[36] PG&E (Pacific Gas & Electric). 2017a. *EPIC Project 1.02 – Demonstrate Use of Distributed Energy Storage for Transmission and Distribution Cost Reduction*. Electric Program Investment Charge (EPIC) project report, June 20. San Francisco: PG&E. https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.02.pdf.

[37] Chacon, B. 2017. "Xcel Energy Investigates Use of Battery Storage." *T&D World*, January 24, 2017. https://www.tdworld.com/renewables/xcel-energy-investigates-use-battery-storage.
Cleveland, F.

[38] Adhikari, S. 2015. "APS Solar Partner Program." Presented at the Integrating PV in Distribution Grids: Solutions and Technologies Workshop, Golden, CO, October 22-23, 2015. https://www.nrel.gov/esif/assets/pdfs/highpenworkshop_adhikari.pdf.

- Mechanical Energy Storage: Mechanical energy storage systems take advantage of kinetic or gravitational forces to store input energy. An example is flywheel systems that store energy in the form of rotational energy.
- Hydrogen Energy Storage: Electricity can be converted into hydrogen through electrolysis process. The hydrogen can be then stored and eventually re-electrified which has a low efficiency. However, the produced hydrogen can be utilized as fuel for hydrogen-fueled vehicles or blended into natural gas systems which is more efficient since it does not require another energy conversion cycle to deliver the energy to end-use customers.
- Pumped Hydro Power: Pumped hydroelectric storage facilities store energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation. During periods of high electricity demand, power is generated by releasing the stored water through turbines in the same manner as a conventional hydropower station. During periods of low demand (usually nights or weekends when electricity is also lower cost), the upper reservoir is recharged by using lower-cost electricity from the grid to pump the water back to the upper reservoir. Pumped hydro storage is typically more viable for use as a very large-scale storage medium rather than a distributed resource due to high capital cost and environmental requirements.

o *D-STATCOM and D-SVC:* Originally, static synchronous compensators (STATCOMs) and static var compensators (SVCs) were used to provide reactive power support on transmission systems and are now being used in distribution systems, where they are called D-STATCOM and D-SVC. These technologies are used to provide or absorb reactive power to mitigate voltage violations. This also includes fast reactive power support to mitigate voltage flicker or transient over/under voltages. An example is Ergon Energy in Australia, which has experienced very high penetrations of PV. Ergon Energy has deployed several D-STATCOM systems, either standalone or in combination with advanced inverters[39]. They found that D-STATCOM can regulate voltage and is less expensive than traditional approaches for mitigating voltage violations.

o *Flexible Interconnection/Active Network Management:* Flexible interconnection refers to the ability of the developer to avoid upgrades by accepting that its system may have real power curtailed as necessary to avoid system violations. In the United Kingdom (UK), this option has been explored extensively for interconnection of variable renewable energy resources, where it is typically referred to as active network management (ANM), which can also be included in DERMS[40] functionality. New York is piloting flexible interconnection called flexible interconnect capacity solution (FICS) with two DER projects—one 2-MW PV plant and one 450-kW farm waste digestor—but no results are

[39] Condon, D., D. McPhail, and D. Ingram. 2016. "Application of Low Voltage Statcom to Correct Voltage Issues Caused by Inverter Energy Systems" Presented at the Australasian Universities Power Engineering Conference (AUPEC), Brisbane, Australia, September 25-28, 2016. doi: 10.1109/AUPEC.2016.7749332.
[40] Distributed Energy Resources Management System

yet available[41]. Flexible interconnection can be acceptable when the expected curtailment risk is lower than the cost of system upgrades that would otherwise be required. Some data on the costs of implementing ANM or DERMS can be found in NREL's Distribution Grid Integration Unit Cost Database[42].

- *Advanced Communication and Control Schemes:* Utilization of advanced communication and distribution control schemes such as ADMS and/or DERMS can help mitigate multiple DERs impacts on the distribution system. Requirements for the communications systems vary depending on the functionality. HECO suggests the following requirements for DER and storage management applications:
  - 20 milliseconds – 14 seconds latency,
  - 9.6-56 kilobits per second bandwidth,
  - 90%-100% coverage,
  - 99%-99.99% reliability,
  - 1-hour backup,
  - High security
  - Ensured Interoperability

3.3.6 Cost Allocation

DERs interconnection cost allocation is an issue for utility companies, public utilities commissions, and involved stakeholders. Stakeholder feedback compiled as part of the Gap Analysis process included several comments from different stakeholders related to cost causation, equity, and benefit attribution concerns. The two main questions that need to be answered when developing a solution for cost allocation are the following:

- How can the benefits that different stakeholders realize from grid upgrades be identified?
- How can upgrade costs be allocated efficiently and equitably to beneficiaries?

Cost allocation approaches across the United States vary significantly across different utilities and states.

3.3.6.1 State of Development

Although the allocation of the cost related to DERs interconnection in distribution systems is a relatively emerging focus area, practices for transmission systems cost allocation have long been debated that can be used to inform DER interconnection cost allocation at the distribution level.
A key principle to use for cost allocation is: "*All approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them[43].*" Another way of expressing this principle is to say that those who benefit from a facility should pay for the facility. The Seventh Circuit Court of Appeals has stated that: "*To the extent that a customer benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the*

[41] REV Connect. 2018. "Lessons from REV Demos in New York's Energy System." From REV Connect Webinar Series, January 17, 2018. https://nyrevconnect.com/wp-content/uploads/2018/01/Webinar2_Demo-Principles-v6-01-17-18.pdf.
[42] https://www.nrel.gov/solar/distribution-grid-integration-unit-cost-database.html
[43] K N Energy, Inc. v. FERC. 1992. 968 F.2d 1295, 1300 (D.C. Cir. 1992).

expectation of its contributions the facilities might not have been built or might have been delayed[44]*.”*

3.3.6.2 The Conventional Cost-Causer-Pays Approach

This approach, referred to as “cost causer pays” method, maintains that the DER applicant is required to pay for all the costs, including the full cost of distribution system upgrades deemed necessary to accommodate the project. The benefits of this method are the following:

- It follows the principles of cost causation.
- It provides a location-based signal that can discourage projects in locations with high upgrade costs but not penalize those with low upgrade costs, thus lowering overall integration costs.
- It is relatively simple in execution.

However, this method has some shortcomings as well. The main shortcoming comes from situations in which future DERs also benefit from the newly upgraded circuit, yet are not incurring any extra costs, putting the burden of paying for network upgrades entirely on the first DER applicant to trigger the need for a new facility (the cost causer). This issue is commonly referred to as a “free-rider” problem when an entity or group can use a resource without paying for it. Other issues include:

- Procedural Delays: Applicants trying to evade the upgrade costs may put the interconnection queue to a halt for that circuit until somebody eventually pays the upgrade costs.
- Project Termination: Smaller DERs may be unable to pay for the high upgrade costs, while larger projects may also not accept the high upgrade costs; this may cause upgrades never being done.

3.3.6.3 Emerging Solutions

In this section, some alternative options for DERs cost allocation that are currently being explored by some U.S. utilities are reviewed.

- Group Study/Group Cost Allocation
  This method spreads upfront interconnection costs among a group of DER applicants being evaluated at the same time. Multiple applicants are studied as a group and identified total upgrade costs are spread across all projects within the group according to their relative contributions toward requiring the upgrade. As an example of implementing this method, in California, projects larger than 1 MW are required to pay for distribution system upgrades that are needed to accommodate their interconnection and, under the electric Rule 21 tariff, projects that fail an “interdependency test” are put into a group study process that explores the impact of multiple projects at the same time and charges DERs proportional to their contributions to the costs (both interconnection study cost and upgrades cost).
  The challenge with this method is that every applicant in the group must stick through the entire group-study process, which can slow the interconnection process as projects change

[44] ICC v. FERC. 2009. 576 F 3d at 476. https://www.dwt.com/files/uploads/Documents/Advisories/Illinois%20Commerce%20v%20FERC.pdf.

their designs or applicants drop out. Interconnection studies may need to be repeated and costs reallocated, which could increase study costs and the time to process applications.

- Post-Upgrade Allocation
  Based on this method, a single entity pays for the upfront costs of an upgraded facility. As new systems connect and use the upgraded facility, the entity that originally paid for the upgrade is reimbursed. Two variations of this method are currently identified.
  - *Cost-Causer Post-Upgrade Cost-Sharing Allocation:* According to this method, the initial cost causer pays for the entirety of the upgrades caused by their request for interconnection. The first applicant who pays for the costs will then be reimbursed by future projects that apply for interconnection to the upgraded circuit.
  - *Utility Prorated Cost-Sharing Allocation:* In this method, the utility waits until a developer interconnection request triggers a needed upgrade in the system. Then, the utility pays initially for the entirety of the upgrade costs, which frees up some capacity for DER interconnection. The utility calculates the $/kW cost for that upgrade and charges each DER applicant based on their total project kW size.

- Preemptive Upgrade Cost-Sharing Allocation
  This method is initiated by a New York Reforming the Energy Vision (NY REV) pilot being run by National Grid to examine a preemptive upgrade and cost-sharing approach[45]. The idea behind this method is that the utility pays for and implements upgrades in some locations and advertises the available capacity for DERs interconnection along with the associated costs per kW of DER.
  Ground fault overvoltage is a common issue that needs to be addressed during the DERs interconnection process. The typical utility solution is the implementation of a "3V0" protection scheme on the substation's high voltage side. This scheme can be expensive for developers of relatively small DER projects and can take time to implement. In the NY REV pilot, the utility pays for the initial upgrade for 3V0 ground-fault protection needed for higher penetrations of DERs; future projects that are larger than 50 kW and interconnect to the upgraded substation pay the utility a one-time prorated fee (which is evenly divided among projects by kW size) to cover the total cost of the 3V0 upgrade.
  The issues with this method are: 1) when there are not enough DERs to pay for the upgrade costs and the cost-recovery risk is shifted to other distribution customers; 2) there is little/no incentive for a utility to seek developers to interconnect; 3) it is difficult to prescribe how many preemptive upgrades can achieve the intended results. This method has advantages, namely: 1) marginal DER developer does not have to pay upfront capital costs; 2) ideally, upgrade costs are shared among those who benefit.

In the state of Maine, Rule 407 Chapter 324 defines the procedure for cost allocation of upgrades. The process defined by Rule 407 Chapter 324 is similar to *Cost-Causer Post-Upgrade Cost-Sharing Allocation* method explained above. It is mentioned in Chapter 324 that "The

[45] National Grid. 2017. *National Grid DG Interconnection REV Demo Project*. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV). Niagara Mohawk Power Corporation d/b/a National Grid. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6B0377EF-F949-4DAA-A164-AB8ABB019E5B}.

Interconnection Customer shall only be responsible for paying for that portion of the interconnection costs resulting solely from the Interconnection Facilities or Distribution Upgrades required to allow for safe, reliable parallel operation of the ICGF with the T&D Distribution System; provided, however, the T&D Utility may only charge an Interconnection Customer for the Interconnection Facilities or Distribution Upgrades specifically necessary for and directly related to the ICGF. Such upgrades may include transformers, distance for express feeders, reconductoring upgrades, and similar upgrades. To the extent that later-queued ICGFs benefit from Contingent Upgrades (i) that were paid for by earlier-queued Interconnection Customers and (ii) for which the good faith estimate of costs is more than $200,000, the T&D Utility will identify a prorated portion of the cost responsibility in each Interconnection Agreement for later-queued Interconnection Customers. If the Generating Capacity of the ICGF is less than 250 kilowatts, the Applicant may elect in writing to not participate in cost sharing." Although this rule is used for cost allocation, CMP requested a waiver for Transmission Ground Fault Over Voltage (T-GFOV) cost allocation which was approved by MPUC in May 2021, documented in Docket No. 2021-00082. According to this docket, CMP's proposal was to implement the existing cost sharing provisions of Chapter 324 for T-GFOV upgrades, with the following adjustments:

1. In instances where multiple projects are seeking interconnection to a common distribution transformer requiring TGFOV upgrades, CMP will allocate the upgrade costs among cost sharing projects on a pro-rata basis on MW capacity (AC);

2. For substation transformers with a currently identified need for T-GFOV protection and identified triggering and cost sharing projects:

a. CMP will incorporate these costs in System Impact Study (SIS) results and interconnection agreements (IAs) for the impacted projects;

b. If projects do not accept these upgrade costs and withdraw from the interconnection queue, their costs will be reallocated among the remaining projects;

c. Since this could result in a cascading process, final cost responsibility will not be known with certainty until all projects have either executed IAs accepting allocated costs or withdraw from the queue;

d. Since cost sharing projects and the associated upgrade cost allocation is known up front, CMP will waive administrative fees for implementing this initial cost sharing. (Fees will still apply if future projects seek interconnection and trigger an incremental reallocation of costs);

e. For the initial allocation of shared costs among known interconnecting projects, CMP will fully allocate T-GFOV upgrade costs for these projects and will not apply the $200,000 minimum threshold to cease reallocation under Section 12(G) of Chapter 324;

f. Additional subsequent interconnection requests to the same transformer will be subject to the normal Chapter 324 cost sharing provisions using a MW capacity-based allocation (Chapter 324 cost thresholds and administrative fees will still apply).

3. For substation transformers with a T-GFOV mitigation need triggered by future interconnection applications and System Impact Studies:

a. Upgrade costs will be assigned to the triggering project;

b. Additional subsequent interconnection requests to the same transformer will be subject to the normal Chapter 324 cost sharing provisions using a MW capacity-based allocation (Chapter 324 cost thresholds and administrative fees will still apply).

3.3.7 Future DER Growth Forecast

An accurate forecast of future DER growth plays an important role in making optimal planning decisions for the future of distribution systems. Currently, there are two categories of approaches used for estimating future DER deployment: *The top-down method* and the *bottom-up method.* The characteristics of these two categories of methods are outlined in Table 2. Top-down methods are based on the assumption that modeling individual customers is not necessary (or feasible) for forecasting territory-wide DER deployment. This assumption facilitates data collection, specifications of relationships of interest, and model execution. Bottom-up modeling, on the other hand, seeks to model each customer in the utility territory and the influence of their unique characteristics on the adoption of DERs. The main characteristics used in this modeling approach are the customer's electrical consumption, building and roof profile, and applicable retail tariffs, as well as any other customer-level attributes that are known.
The choice of a DER-adoption model for specific analyses is not always obvious and is still a topic of research. However, one clear finding is that DER adoption should be accounted for in both transmission and distribution plans. As a corroborating example, a recent NREL[46] publication[47] estimated that poor DER adoption forecasts could cost utilities as much as $7/MWh of served load from suboptimal asset investments.

[46] National Renewable Energy Laboratory
[47] Gagnon, P., G. Barbose, B. Stoll, A. Ehlen, J. Zuboy, T. Mai, and A. Mills. 2018. *Estimating the Value of Improved Distributed Photovoltaic Adoption Forecasts for Utility Resource Planning*. NREL/TP-6A20-71042. Golden, CO: National Renewable Energy Laboratory; Berkeley, CA: Lawrence Berkeley National Laboratory.

Table 2. Methods for DER deployment prediction[48]

	Top-down			Bottom-up
	Time Series	**Econometric**	**Bass Diffusion**	
Pros	Simple, easy to estimate and validate.	High familiarity and use in other domains, explanatory value.	Easy to specify, intended to model new technology adoption.	Excels at spatial predictions, models unique attributes of consumers.
Cons	Does not represent inherent technical limits to adoption, for instance, that there are a finite number of households. Does not capture changes over time to adoption likelihood (e.g., decreasing capital costs).	Better suited to predict aggregate adoption than individual or feeder-level. Based on population central tendencies, which can fail to capture outliers or early adopters.	Easy to overfit and can be sensitive to transient market effects. Relatively inflexible to add additional explanatory variables.	Requires significant investment in data and computing resources.
Data required	At minimum, only requires observations of aggregate historical deployment over time.	Very flexible in data used; modelers can incorporate nearly any data available that might explain observations. However, modelers should use standard statistics test to avoid overfitting.	In its simplest formulation, only needs historical time series of adoption. Further specifications can incorporate impact of product prices, advertisement, or other time-varying features	Modelers can incorporate nearly any data available at agent level: electrical consumption, building and roof profile, applicable retail tariffs, etc.
Example use case	Projecting adoption to fit an exogenous policy, such as a DPV carve-out in a state Renewable Portfolio Standard.	Understanding factors that explain historical adoption of DPV.	Forecasting aggregate-level adoption in a utility's territory.	Generating household-level adoption probabilities for use in distribution planning or hosting-capacity analysis.

48 https://www.nrel.gov/docs/fy19osti/72102.pdf

3.3.8 Storage + Solar Interconnection

The penetration level of advanced energy storage systems, including batteries and flywheels, is growing quickly. Best practices for storage interconnection are still emerging and evolving. Here, key considerations that have been identified for adopting the interconnection process of energy storage are summarized.

- *Including Energy Storage as Part of State Interconnection Standards:* The definition of "generating facilities" in interconnection standards often omit to mention energy storage, which can create ambiguity about the ability of a storage system to apply under the rules.
- *Including Provisions to Address Different Energy Storage Configurations and Clarifying Which Level of Review Each Type of System Will Undergo:* Energy storage technologies can be deployed under different configurations. For example, in the case of a BTM solar + storage system, the storage device's role may be simply to capture electricity generated by the solar system during the day for use onsite after the sun goes down, rather than injecting it back to the grid (i.e., "non-exporting"). Or it may be designed to export power back onto the grid for sale to the utility under net metering (where allowed) or other applicable tariffs. Energy storage systems can also use technologies to limit the export to the grid, which can affect the review for potential system impacts.
    - Addressing Non-Exporting and Limited-Exporting Systems: Recognizing that non- and limited-export systems have different impacts on the system than do full-export systems enables states to craft a more appropriate study process that looks only at the impacts that could be realized. For utilities to study non-and limited-export projects, they must be provided adequate assurance that the devices being used to control export have been tested to perform accordingly.
    - Addressing Inadvertent Export: Although energy storage system controls can avoid exports onto the grid, there are times when non-exporting or limited-exporting systems will inadvertently export limited amounts of power for very short durations (like when unanticipated load fluctuations occur). California, Hawaii, Colorado, and Nevada have addressed this issue by incorporating inadvertent export into their standards[49]. The rules have allowed up to 30 seconds of maximum export for any single event, with provisions to ensure total inadvertent exports remain within an acceptable limit.
    - Specifying the Most Appropriate Level of Review, Based on System Design Configuration and Operational Controls: For example, non-exporting systems could be reviewed in a more expedited manner by not applying the technical screens in the Fast Track process that relates to the amount of electricity onto the grid.
    - Providing Transparent Screen and Study Results to Allow for Reasonable System Modifications to Address Technical Concerns, If Needed: Some states provide sufficient information to the interconnecting customers regarding screen or study results to enable applicants to alter their system design to address concerns, rather than requiring a new interconnection application. A good example is one of the revisions made to California Rule 21 on September 2020 titled "conditions that

[49] SCE (Southern California Edison). 2016. *Rule 21: Generating Facility Interconnections*. U 338-E. Rosemead, CA: SCE.

allow distributed energy resources to perform while avoiding upgrades". Based on these revisions, California's three big investor-owned utilities are ordered to develop processes to allow fast-track interconnection of DER projects that use "limited generation profiles" to modify their impact on the grid. Under state law AB 327, California's utilities provide Integration Capacity Analysis (ICA) maps online showing DER hosting capacity on individual grid circuits. That capacity can change from hour to hour or season to season, largely from the daily rise and fall of solar power. A new solar system that might be easily added to a circuit under average conditions could still exceed its capacity during a few hours, such as on cool yet sunny days when solar generation floods the grid. The new rules allow DERs to promise to manage their output on a set monthly schedule that changes from hour to hour, possibly by curtailing solar output, or more likely, by storing it in batteries to avoid significant upgrade costs.

- *Clarifying Rules to Account for the Generation and Load Aspects of Energy Storage:* Clear rules to apply to energy storage systems as both generating and load units for technical and upgrade cost allocation procedures are necessary.
- *Revise Interconnection Applications, Agreements, and Associated Documents to Correctly Obtain Information about Energy Storage.*
- *Ensure Appropriateness of Charging and Discharging for BTM Solar + Storage Systems for other Renewable Energy Policy Compliance:* Specifically, for BTM solar + storage systems which are configured to primarily serve customer load and may export excess PV energy onto the grid, there is a need to guarantee that the excess power injected into the grid is generated by the NEM-eligible renewable energy.

3.3.9 Active Management of DER Smart Inverters for Voltage Support

One of the primary challenges with increasing penetrations of DER on the distribution system is voltage management. Traditional approaches like setting high feeder-head voltages to maximize voltage drop, regulator load drop compensation settings, or voltage-controlled capacitor banks are no longer as effective at preventing voltage violations and can actually have significant negative consequences in high DER environments. In Pennsylvania, PPL is piloting direct inverter reactive power controls to improve their ability to manage distribution system voltages without requiring additional interconnection costs or capital investments. This pilot, which began in January 2021, is designed to test and evaluate: 1) The costs and benefits of monitoring DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means. 2) The costs and benefits of active management of DERs as compared to the benefits available through the use of inverter autonomous grid support functions. Figure 10 shows an overview of the Pilot, which begins with a PPL Electric customer filing a DER interconnection application. Approved DER interconnection applications will receive a DER management device and be assigned to a customer group.

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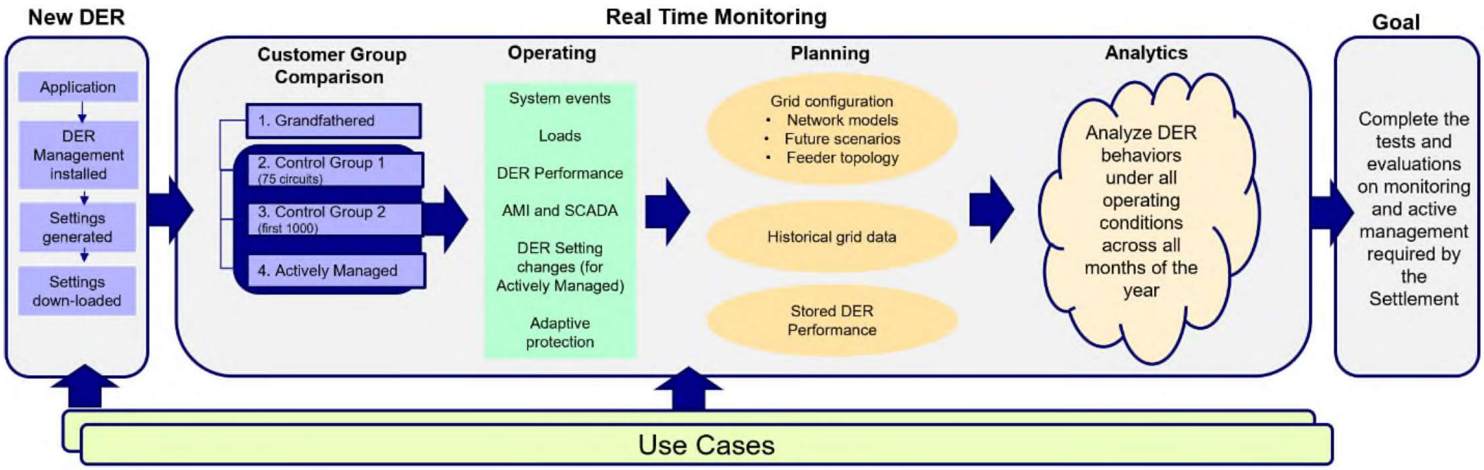

Figure 10. PPL pilot program overview

The DER management architecture used for this pilot is shown in Figure 11.

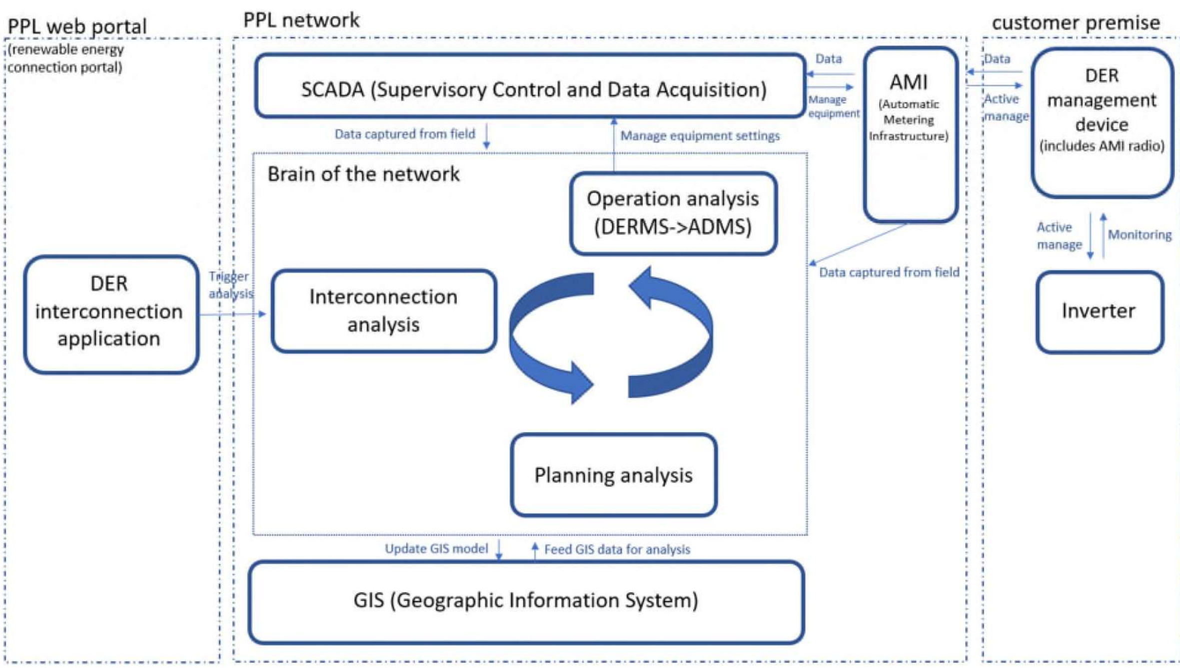

Figure 11. PPL's Pilot DER management architecture

- **DER Settings and Control in PPL's Pilot Program**

In the Pilot program, PPL plans to use autonomous Volt/VAR as the default voltage management method for all the inverters. They will establish and maintain default Volt/VAR settings based on the location and impact of each DER, as well as voltage ride-through and frequency ride-through functions which meet or exceed PJM Interconnection LLC's ("PJM") guidelines. Also, alternative voltage management modes and settings may be used to reduce or eliminate distribution system upgrade costs to interconnect customers with their agreement.

Prior to the customer completing the DER installation and submitting the certificate of completion (COC), a Volt/VAR curve will be calculated and stored in a database to be sent to the inverter following its installation. Each Volt/VAR curve will be calculated using the DER's location on the distribution system, kW nameplate, calculated voltage rise, and other pertinent data.

DERs in Control Group 1 and Control Group 2 will be monitored using DERMS/ADMS and the AMI Mesh Network. Control Group inverters will exclusively use autonomous grid support functions, which will dictate the inverter's operational behaviors, using only the local conditions as input.

In the Actively Managed Group, the developed Volt/VAR curve will be used until field conditions deem a power factor override or a change of power factor is necessary to maintain acceptable system conditions. In operating scenarios where the distribution system is configured abnormally due to maintenance or an outage, DERMS/ADMS may manage these inverter settings by "overriding" the autonomous Volt/VAR curve and using a specific Constant Power Factor until system conditions return to acceptable levels.

- **Pilot Program Anticipated Benefits**

The benefits anticipated by PPL from implementing the Pilot program are summarized in Table 3.

Table 3. PPL's value proposition and anticipated benefits from the Pilot project

Reliability	a. Enhance operational flexibility
	b. Improved excursion ride-through
	c. Improved hidden load visibility
Power Quality	d. System upgrades deferred / avoided
	e. Increased hosting capacity
	f. Improved long-term forecasting
	g. Improved voltage management
Safety	h. Safer work environment

- **Use Cases**

These use cases cover relevant scenarios under which DERs would interact with the electric distribution system. By leveraging the DER management devices' ability to monitor and/or manage the DERs, several beneficial objectives can be achieved in each use case. The use cases include:

1. Voltage violation at DER Point of Interconnection ("POI")

2. Voltage violation mitigated by DERs on the circuit
3. Voltage violation during planned switching
4. System restoration
5. Hidden load impact on load forecasting
6. DER active management impact on voltage management
7. DER active management impact on hosting capacity increase and deferral of capital upgrade
8. DER operation in emergency conditions and in active work zones

3.4 Gap Analysis

As discussed previously, effective integration of DER to the distribution system is critical in order to maximize benefits and minimize costs across all stakeholder groups. Within this section, a gap analysis is performed for each utility to identify opportunity areas where changes to or additions of tools, functionality, data, or other means are likely to help meet identified stakeholder needs, alleviate stakeholder concerns, or improve overall outcomes. This analysis is inherently future-looking and is not intended as a judgment on the reasonableness of past decisions or investments. It is also important to recognize that the gap areas identified, and potential solutions will have different degrees of burden with regard to cost and timeline of implementation, as well as the expected timing of their need. These details will be explored further in a forthcoming Roadmap Report.

3.4.1 CMP

1) **Data Quality –** Within the investigation, CMP identified challenges with data quality, especially related to distribution phase assignment and customer to service transformer mapping. CMP identified their planned Grid Model Enhancement Project, including a relatively comprehensive distribution system audit effort on the whole system, as the means to improve data quality. The successful and timely execution of this project is very important to DER interconnection efforts, as the interconnection studies and subsequent DER interconnection costs can be significantly affected by poor model quality and the conservative assumptions necessary to perform system studies under such conditions. Data and model quality is also foundational to advanced system operations and full utilization of CMP's forthcoming Spectrum ADMS platform.

2) **Hosting Capacity -** CMP is currently in the pilot stage of developing Hosting Capacity maps and has stated intentions to develop these capabilities and publish the results in 2022. Improving non-utility stakeholder access to distribution system information was identified as a high priority by many stakeholders. When done effectively, Hosting Capacity and system information availability can guide developers to sites with lower interconnection costs and reduce the volume of applications submitted, which do not ultimately reach the construction phase. They can also help to establish more clear expectations with regard to interconnection costs and potential upgrade timelines. The PG&E map identified within Section 3.3.1 of this report provides a leading example and includes a variety of advanced functionality that has been added over several iterations and through significant efforts.

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Publishing and continuing to refine Hosting Capacity over time will help improve the usefulness and utilization of the end product.

3) **Voltage Controls –** Maintaining power quality and effectively controlling voltage are critical utility functions and will be made more challenging by the increasing penetrations of DER on the distribution system. Currently, when it comes to DER control, CMP currently maintains operational on/off indication and visibility through SCADA-controlled reclosers at the point of interconnection (POI) for DERs larger than 1 MW in size. For more traditional resources, CMP has identified plans to begin installing communication devices for remote capacitor management. Improving voltage control through communications and controls over capacitors, regulators, and LTCs, is a potentially cost-effective means to help manage the complexity and improve system voltage visibility and control in the face of high DER penetration. Beyond traditional resources, it is also worthwhile exploring the potential to actively communicate with and control DER as a means of reducing interconnection costs, improving hosting capacity, and reducing the need for new infrastructure. Enhancing existing controls can reduce the potential need for more costly voltage management solutions like D-STATCOMs or reconductor upgrades. Using DERs benefits for voltage management also addresses stakeholders' concerns about not seeing any benefits from DERs to the distribution systems in Maine. Implementation of such programs, especially DER controls, are highly dependent on supporting regulatory processes and customer engagement and are likely to be medium to long-term solutions. There is also non-trivial up-front and ongoing investment in communications infrastructure, as well as the implementation of ADMS control modules to support such efforts. CMP is deploying Spectrum ADMS and identified Optimal Power Flow (OPF) as a module they were interested in leveraging once model data quality is sufficient, following Grid Model Enhancement Project.

4) **Time-Series Profiles -** CMP includes DER resources within distribution planning studies using capacity factors to estimate alignment with substation peak load. These values can provide reasonable assumptions for DER performance in planning studies at lower DER penetrations and for relatively typical distribution circuits but can be less accurate outside of those scenarios. For the long-term, as the penetration level of DERs in distribution systems increase along with EVs, transition to more data-driven and time-series analyses is a need. This transition is even more critical when solar PV accounts for a high percentage of new DERs being interconnected as their peak generation may not align with peak load in the system. Improvement in this area can help CMP more accurately assess the impact of DERs on reliability and stability, which is one of the concerns raised by stakeholders. Implementation of such methods should be reasonable in short to medium term without significant capital costs but may increase study complexity and subsequent study costs and timelines.

5) **Ride-Through -** As a concern raised by stakeholders and considering significant DERs interconnection requests and goals in the State of Maine, looking into using voltage and frequency ride-through capabilities of inverter-based DERs to improve stability and

reliability of the bulk electric system and, subsequently, the distribution system, can be a prudent investment area and has been recommended by ISO-NE.

3.4.2 Versant

1) **Hosting Capacity -** Versant does not currently publish a Hosting Capacity map and stated that they were evaluating alternatives for a solution. Following through on the development and deployment of Hosting Capacity information will be a critical next step. Improving non-utility stakeholder access to distribution system information was identified as a high priority by many stakeholders. When done effectively, Hosting Capacity and system information availability can guide developers to sites with lower interconnection costs and reduce the volume of applications submitted, which do not ultimately reach the construction phase. They can also help to establish more clear expectations with regard to interconnection costs and potential upgrade timelines. The PG&E map identified within Section 3.3.1 of this report provides a leading example and includes a variety of advanced functionality that has been added over several iterations and through significant efforts. Publishing and continuing to refine Hosting Capacity over time will help improve the usefulness and utilization of the end product.

2) **DER Application Portal –** Versant currently utilizes a primarily manual process for DER application processing and does not accept online application submission or payment except via email. As DER penetration increases and interconnection request volumes increase, manual processing is likely to become resource-intensive and potentially is likely to cause significant delays in applications processing. As the future volume of interconnection requests increases, stakeholders are concerned about the interconnection applications processing times, which may be improved by increasing process automation, and transitioning to a DER Application portal. Data availability of queued DER and integration with CYME can also improve interconnection study results and minimize manual modeling efforts, which may further increase efficiency and reduce processing time. The deployment of such technology is typically a short to medium-term project, with cost and price structures varying significantly.

3) **Ride-Through -** As a concern raised by stakeholders and considering significant DERs interconnection requests and goals in the State of Maine, looking into using voltage and frequency ride-through capabilities of inverter-based DERs to improve stability and reliability of the bulk electric system and, subsequently, the distribution system, can be a prudent investment area and has been recommended by ISO-NE.

4) **Voltage Controls -** Maintaining power quality and effectively controlling voltage are critical utility functions and will be made more challenging by the increasing penetrations of DER on the distribution system. When it comes to DER control, Versant currently has only on/off control over DERs of sizes larger than 1 MW in Bangor Hydro District (BHD) and 0.5 MW in Maine Public District (MPD) through SCADA-controlled reclosers at the point of interconnection (POI). Improving voltage control through communications and

controls over capacitors, regulators, and LTCs, is a potentially cost-effective means to help manage the complexity and improve system voltage visibility and control in the face of high DER penetration. Beyond traditional resources, it is also worthwhile exploring the potential to actively communicate with and control DER as a means of reducing interconnection costs, improving hosting capacity, and reducing the need for new infrastructure. Enhancing existing controls can reduce the potential need for more costly voltage management solutions like D-STATCOMs or reconductor upgrades. Using DERs benefits for voltage management also addresses stakeholders' concerns about not seeing any benefits from DERs to the distribution systems in Maine. Implementation of such programs, especially DER controls, are highly dependent on supporting regulatory processes and customer engagement and are likely to be medium to long-term solutions. Since Versant does not currently have an ADMS system deployed or concrete plans to procure one, this is likely to be a longer-term solution, but may add some additional value to a future ADMS deployment.

5) **Time-Series Profiles –** Versant does not currently utilize time-series information when studying system impacts of DER. For the long-term, as the penetration level of DERs in distribution systems increase along with EVs, transition to more data-driven and time-series analyses is a need. This transition is even more critical when solar PV accounts for a high percentage of new DERs being interconnected as their peak generation may not align with peak load in the system. Improvement in this area can help Versant more accurately assess the impact of DERs on reliability and stability, which is one of the concerns raised by stakeholders. Implementation of such methods should be reasonable in short to medium term without significant capital costs but may increase study complexity and subsequent study costs and timelines.

Table 4 shows a summary of gaps for both utilities regarding DERs integration, control, and management.

Table 4. Summary of gaps for both utilities regarding DER

Versant	CMP
Hosting Capacity	Hosting Capacity
DER Application Portal	Data Quality
Ride-Through	Ride-Through
Voltage Controls	Voltage Controls
Time-Series Profiles	Time-Series Profiles

4 Electric Vehicles (EV) and Electrification Adoption Modeling and Planning

Climate Action Plan put Maine on a trajectory to decrease greenhouse gas emissions by 45% by 2030 and 80% by 2050[50]. One of the key actions that can make this happen is electrification and EV adoption in the upcoming years. When emissions are analyzed by vehicle type, 59% of Maine's transportation-related emissions are from light-duty passenger cars and trucks; 27% are from medium- and heavy-duty trucks; and the remaining 14% come from rail, marine, aviation, and utility equipment vehicles. Therefore, reducing emissions from transportation is a significant piece of Maine's overall effort to curb state emissions by 45% by 2030. The state's Climate Action Plan estimates Maine needs 219,000 light-duty EVs on the road by 2030 to meet its emissions targets[51]. Considering this goal, Efficiency Maine Trust board uses several incentive programs to accelerate EV adoption across the state. Currently, many governmental entities have begun using the available grants and electrifying their fleets. On the other hand, electrifying fossil fuel-based space and water heat pumps is another activity that is being proceeded by Efficiency Maine Trust board. As a result, it is expected that electrification and EV utilization in Maine will happen quickly in the upcoming years. It is essential that the utilities get prepared for this level of electrification and EV adoption.

In this section, first, the Climate Action Plan and Efficiency Maine Trust's board future goals related to EV and electrification adoption are summarized. Then the stakeholder needs and their suggestions about EV and electrification adoption are expressed. In the third part of this section, several examples of electrification and EV adoptions are introduced, along with their benefits and challenges. Last part of this section, the CMP and Versant are benchmarked against the future goals, stakeholder feedback, and the best practices, and the key areas for future improvement are identified.

4.1 Regulatory Requirements [52]

Maine Climate Council Goals:

- The new roadmap driven by Maine Climate Council says high-speed electric vehicle charging and EV rebates for low and middle-income drivers are the best short-term strategies to lower carbon emissions. It also touches on ways to reduce driving in the state altogether, a challenge, especially in rural Maine.
- Maine's climate plan aims to put 41,000 new electric vehicles on the road by 2025 and 219,000 by 2030, with increasing reductions in vehicle miles traveled. Despite the steady

[50] *Maine Won't Wait.* Maine Climate Council. Dec. 2020. Page 6. https://www.maine.gov/future/sites/maine.gov.future/files/inline-files/MaineWontWait_December2020.pdf

[51] *Maine Won't Wait.* Maine Climate Council. Dec. 2020 Page 39. https://www.maine.gov/future/sites/maine.gov.future/files/inline-files/MaineWontWait_December2020.pdf

[52] https://www.maine.gov/future/sites/maine.gov.future/files/inline-files/Maine%20Clean%20Transportation%20Roadmap.pdf

growth of EV sales in the past few years, it's a high goal for the state. For example, in the first half of 2021, 3.7% of new vehicles sold in the state were EVs.

- By 2022, Maine Climate Council plans to develop a statewide EV Roadmap to identify necessary policies, programs, and regulatory changes needed to meet the state's EV and transportation emissions reduction goals.
- By 2022, Maine Climate Council plans to create policies, incentives, and pilot programs to encourage the adoption of electric, hybrid, and alternative-fuel medium and heavy-duty vehicles, public transportation, school buses, and ferries.

Efficiency Maine Trust Requirements:

- **Electric Vehicle Supply Equipment (EVSE) Promotion Requirement:** Electric utilities must design rates to encourage EVSE use and file a rate schedule proposal with the Maine Public Utilities Commission by November 1, 2021. Proposed EVSE must align with the "Maine Won't Wait" climate framework. (Reference House Bill 245, 2021)
- **Maine must limit greenhouse gas (GHG) emissions to achieve the following reductions:**
    - By January 1, 2030, reduce overall GHG emissions in the state to 45% below 1990 levels.
    - By January 1, 2040, be on an annual trajectory to achieve the 2050 annual emissions level.
    - By January 1, 2050, reduce overall GHG emissions to 80% below 1990 levels.

Public Law No. 1766 Requirements: [53]

- **Purpose**: PL 1766 was enacted to increase the use of electric heating within Maine for economic security and to meet Maine's climate objectives.
- **Summary**: This act sets forth the goal to have 100,000 heat pumps installed in Maine by 2025 to create jobs and keep energy costs down, while reducing Maine's dependence on fossil fuels.
- **Impact on Distribution Utilities**: Distribution utilities will see an influx of heat pumps being utilized across the grid.

EV Rate Changes

MURRDI provided recommendation to change Maine's EV rates, to enable load flexibility. MURRDI also suggests Maine move toward a more dynamic grid with more granular load flexibility capabilities in a concerted manner. Maine legislature directed MPUC to issue an order in September 2021, for utilities to consider time of use rates and/or other dynamic rate structures that more accurately reflect the costs to generate and provide power. CMP and Versant have both set forth plans that use more dynamic rate structures to discourage charging during peak demand.

[53] LD No. 1766 An Act to Transform Maine's Heat Pump Market to Advance Economic Security and Climate Objectives. 129th Maine Legislature. May 21, 2019.

According to the Cadmus Group report 'Maine Clean Transportation Roadmap,'[54] the time of use rate structure is utilized across 48% of IOUs. MURRDI outlines design considerations for such rate designs as follows:

a. Constructive rates should include energy, capacity, and T&D costs.
b. Set time limits for time varying rate structures should consider demand, costs, and emissions to ensure utilization of the most efficient time periods.
c. Rates should benefit all customers, while protecting low-income ratepayers.
d. Rate designs should be paired with complementary customer side technologies.

CMP found their pilot program to expand the use of it's B-DCFC rate that includes level 2 DC fast chargers, showed the sole participant a savings of 40% on costs of transmission and power delivery. CMP proposed expanding this program and proposed a tariff be created for electric public transit. Another priority was updating marginal costs under the current periods covered under time of use rates to better fit the load profiles they are observing. Versant proposed a rate design that reflects CMP's B-DCFC design for DC fast charging. While neither utility offers special time of use rates for residential customer EV charging, they do offer special time of use rates for general residential rates.

4.2 Stakeholders Needs

This section provides one or a group of involved stakeholders' concerns, ideas, opinions, and suggestions which are taken from "Maine DER Roadmap- Stakeholder Feedback" report directly and summarized in this report. While this process reached a diverse group of stakeholders, it does not reflect all stakeholders engaged in these issues. The goal of this work is to capture the broad concerns and diverse visions among energy businesses, elected officials, system operators, and advocates in an accessible, clear and anonymous summary. No attempts were made to verify any of the factual assertions in the stakeholder comments, except where footnoted. No statement has unanimous agreement from stakeholders – there is a wide diversity of views on the sources, severity and solutions to the challenges of DER integration, and no statement in this report should be attributed to any specific stakeholder. Even when "many stakeholders" raise a concern or support a position, this should not be read to suggest that even a majority of stakeholders hold such a belief.

- **Stakeholders Concerns**
  - There is concern among stakeholders that if electricity prices are seen as rising or excessively volatile, ratepayers will be slow to electrify vehicles.
  - Poor reliability is seen as an obstacle to electrification and electric vehicle adoption. If early adopters see poor results, adoption will be slowed.
  - The distribution grid will need substantial investment to support broad electric vehicle adoption. There will often be grid upgrades needed, such as new transformers, where electric vehicle charging stations are installed and at homes and apartments with EVs.
  - Load integration challenges related to EVs are top-of-mind for stakeholders.

[54] *Maine Clean Transportation Roadmap.* Cadmus Group. Dec. 2021. Link

- Demand charges are seen as an obstacle to electric vehicle adoption.
- Fast charging infrastructure at residences and in public spaces is necessary to support long EV driving. This increases the cost to consumers for electrical upgrades and creates a more dramatic load profile for the system to absorb.
- The policy support for electric vehicles (EVs) in Maine is relatively new - utilities are now working to implement prudent solutions for EV adoption to meet state goals. Both IOUs plan to significantly transition their fleets to EVs.

- **Stakeholders Suggestions**
  - Stakeholders would like to see data on rate design options and creative solutions to encourage adoption while minimizing socialized costs.
  - Widespread charging infrastructure will be key to alleviating range anxiety and enabling long trips.
  - Because tourism is a significant economic driver in northern Maine, Canadian electric vehicle adoption was cited as a reason to invest in electric vehicle charging infrastructure.
  - High costs to individual customers looking to integrate electric vehicles on their properties undermine sustainability goals. Utilities must find more affordable ways to integrate these new technologies to facilitate the adoption process.
  - Maine has a higher-than-average share of emissions coming from transportation, so increasing consumer enthusiasm (and price accessibility) for zero-emission transportation is critical.
  - EV Fast Charger Deployment[55]: Identify and implement temporary measures to advance new EV fast charger (including DC fast charging and clustered Level 2 charging) deployment in the near term, as Maine makes a shift in both peoples' driving habits and their purchase of EVs. Importantly, this should be done soon to be as effective as possible. These measures could include the following:

    1. Temporary mitigation of demand charges for fast chargers, such as a rebate that's phased out over a specific time period.

    2. Consider establishing incentives for fast charger deployment, including consideration of underserved areas.

    3. Identify areas on the distribution system with excess capacity that could be good locations for fast chargers to operate with low demand charges (e.g., at a former industrial facility, at a substation, etc.) and temporarily incentivize deployment and/or usage at those locations, such as by enabling reduced charging prices.

    4. Investigate utility make-ready programs that can reduce the upfront costs of deploying new DC fast-charging stations.

    5. Implement appropriate load flexibility to reduce grid impacts.

[55] This suggestion is derived from Maine Utility/Regulatory Reform and Decarbonization Initiative (MURRDI).

4.3 Best Practices

In this section, several aspects of the EV and electrification adoption are introduced according to the studies and experiences those other entities have had so far. The following subsections are discussed in this section:

- Developing a utility EV strategic plan
- Building a utility electrification team
- Utility-Led Charging Infrastructure Programs
- Integration requirements

4.3.1 Developing a Utility EV Strategic Plan

Developing a comprehensive strategic plan helps the utilities to define the goals and objectives for any EV program and compile necessary information in one place. Many of the Utilities around the United States have developed EV strategic plans that include EV and EV charging objectives for consumers and businesses to address education and planning pieces. According to the 2020 SEPA Utility Transformation Challenge survey (see Figure 12), 42% of the utility respondents were in the process of developing a strategic plan for transportation electrification, with 90% of those doing so voluntarily (i.e., they were not required to do so by government authorities). 51% had already developed a strategic plan for transportation electrification, with 85% having done so voluntarily. Only 5% of utility respondents indicated they had not developed a strategic plan and were not currently developing one.

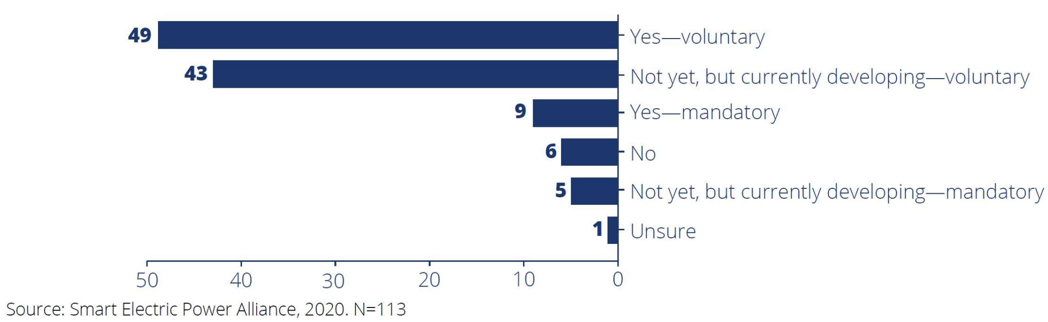


Figure 12. Utility with a strategic plan for transportation electrification

To build a Utility EV Strategic Plan, two following major components should be tackled:

- Market Research and Needs Analysis
- Define the Utility Role in the Market

4.3.1.1 Example: Portland General Electric (PGE) EV Strategic Plan

PGE has a critical role in supporting the rapid, safe, affordable, equitable, and clean deployment of EVs in Oregon. Because PGE operates in a state with aggressive climate goals and a zero-emission vehicle (ZEV) goal of 250,000 registered ZEVs by 2025, the utility is facilitating frictionless interconnection between its system, customer vehicles, and charging stations. Fleet owners across PGE's service territory are gearing up for accelerated deployment of EVs, from municipal segment customers to private business and public transit agencies. Furthermore, PGE understands that effective engagement with its customers, stakeholders and other partners is a critical and necessary step to becoming a consensus builder within the market. Because the PGE system is networked, used, and leveraged by its customers, PGE is unique among other EVSE providers in its ability to capture various benefits from EV adoption. In order to do this, PGE must remain flexible and quickly identify solutions to address the challenges in serving new EV loads.

PGE laid out a comprehensive strategy in its Transportation Electrification Plan (approved in 2020 by state regulators) that aims to drive overall customer benefit and minimize costs of integrating this new load. Three key areas of focus are:

- Developing meaningful rate options for EV drivers to reduce fueling costs and complexity
- Supporting infrastructure deployment, including behind the meter investments, to ensure charging adequacy
- Creating new customer programs to efficiently integrate new EV loads into the grid.

PGE has focused efforts on developing new approaches to serving customers and reducing customer friction wherever possible. To date, areas of focus have included:

- Transit and fleet electrification
- Expanding charging access for EV drivers
- System planning and customer readiness

4.3.1.2 Example: National Grid EV Strategic Plan

National Grid has launched a customer engagement initiative to support EV adoption across its U.S. electric service territories. National Grid manages operating companies in Rhode Island, Massachusetts, and New York, each with a diverse customer base, local market conditions, and regulatory environment. While all three states in which National Grid operates have aggressive climate action goals to deploy at least 3.3 million EVs by 2025, National Grid's customer-facing programs are different in each jurisdiction.

National Grid's customers have concerns about vehicle electrification. Many residential customers worry about insufficient charging infrastructure across their neighborhood. Also, many commercial fleets are unsure how to tackle the new logistical challenges that the electrification of fleet vehicles would bring. National Grid has undertaken extensive work through strategic planning, customer surveys and journey mapping exercises, as well as engaging with stakeholders to understand how the company can best help its customers and states achieve these goals.

Through this work, National Grid identified that it has a key role to play in enabling and deploying affordable EV charging infrastructure, increasing customer education and awareness, and offering other related services to ensure robust and equitable access to the benefits of transportation electrification.

National Grid has designed and launched its first phase of EV charging infrastructure programs in all three states to achieve these goals. It has deployed these programs at different times, and it, therefore, has been able to actively seek and incorporate lessons learned from the states in which programs were deployed first to better inform program design for the states in which programs were deployed later. The National Grid has focused on the following types of programs to date to ensure a comprehensive and fair approach:

- **Residential:** Off-peak managed to charge programs.

- **Commercial:** Level 2 and DC fast charging (DCFC) make-ready infrastructure programs.
- **Fleet (including medium- and heavy-duty vehicles):** Fleet advisory services.

National Grid has also launched marketing and outreach drivers to increase awareness of its programs and the benefits of EV charging for the above customer segments.

4.3.2 Building a Utility Transportation Electrification Team

A skillful transportation electrification team can facilitate internal alignment and leadership as a program is built, launched, and implemented. Inside a utility, there are several departments that can support the EV adoption. Table 5 shows a typical list of utility departments and how they can support EV charging infrastructure programs. Regardless of the team's size, these departments can extend the team to distribute the EV charging programs more broadly and help grow customer engagement in the long term.

Prior to creating a dedicated transportation electrification team, utilities can support EV and charging infrastructure growth by:

- Designating a lead point of contact for EV infrastructure customers (usually one employee serves in this role part-time in addition to his or her primary job).
- Establishing a full-time EV program manager position that guides EV infrastructure program activities across all departments.
- Hiring a contractor to manage EV program activities, such as tracking customer progress from sign-up to installation or performing site walks.
- Establishing a separate interconnection queue for charging infrastructure projects so projects are prioritized appropriately.

When a utility is ready to form a dedicated transportation electrification team, there are many ways to structure the team. The sidebar describes potential approaches to staffing such a team as it grows from small to medium to large.

Several utilities in the US have dedicated transportation electrification teams, including two to 10 or more members. The importance of a dedicated team, regardless of size, is that utility staff are responsible and accountable for EV infrastructure activities, serve as the go-to resource(s) and expert(s), and are dedicated to expanding infrastructure in their communities. An effective utility EV team should be able to leverage vital internal departments/groups that can help make the EV program successful. Below are three examples of small size, medium-size and large-size utility EV teams.

Table 5. Utility departments involved in EV charging programs

EV Project Management Team	Guides and facilitates internal and external rollout of EV programs and activities.	**Strategy**	Helps to develop the programs and activities undertaken by the utility via an EV strategic plan. Also oversees the development of new utility business plans.
Executive Management & Team	Regularly emphasizes the importance of the utility's transportation electrification efforts to employees in departments across the utility. Should be continually updated on EV strategic plans and program progress.	**Regulatory**	Secures regulatory approval for new EV program designs and funding, and ensures public policy decision-makers are updated on EV program and activity progress, customer participation, and public benefits associated with transportation electrification.
Rate Design	Studies, develops, and implements new rate designs tailored for EV charging. Works closely with the transportation electrification team and the regulatory team to determine rate use cases and impacts.	**Customer Research & Communications**	Provides customer segmentation data to target the marketing strategy, and implements the marketing strategy to increase customer program enrollment, EV purchases, and other community outreach and information.
Public Affairs	Ensures governmental and other key stakeholders (e.g., mayors and their staff) understand the benefits to residents and businesses. Can also leverage these relationships to help streamline project permitting with AHJs.	**Community Relations**	Leads outreach efforts to community-based organizations to work with leaders representing low-income and underserved communities.
Media Relations	Coordinates outreach to local media with details about EV programs and milestones. Coordinates social media and blog posts.	**Commercial Account Managers**	Provides program information to large corporate customer accounts. This is often one of the most important groups to reach out to site hosts because the group is typically trusted by customers.
Customer Contact Center	Ensures staff is trained to respond effectively to customer queries via phone, social media, and online chat regarding EV programs, home charging, rates and incentives, and other relevant information.	**Fleet**	Develops and implements a strategy to convert a portion of the utility fleet to EVs to ensure the utility is "walking the talk." Can be showcased as testimonials for customers interested in fleet electrification. Utility workplace charging could also be included as part of a comprehensive approach to utility fleet electrification.
Construction	Coordinates with contractors to install EV charging infrastructure, and other related activities.	**Engineering & Planning**	Assesses the need for utility service upgrades, and determines the infrastructure design and installation requirements.
Technology & Innovation	Approves charging equipment offered by the program to ensure safety and reliability, and evaluates energy management systems, technical standards, communications protocols and interoperability, energy storage integration, vehicle-to-grid and other advanced technology systems. Should be encouraged to participate in forums (such as SEPA) to share and improve their experience.	**Grid Operations**	Monitors and manages the utility's transmission and/or distribution grid, including aggregated DER programs, such as managed charging. Determines when to trigger demand response events and/or resilience related activities to which participating EV chargers could respond.

Source: Smart Electric Power Alliance, 2020.

4.3.2.1 Example for Small Size Team: Orlando Utilities Commission Transportation Electrification

The Orlando Utilities Commission (OUC), a municipally owned public utility in Central Florida, has been working on transportation electrification since 2009 by pursuing grants, customer education activities, and EV charger installation programs. Significant progress was made in 2018 when a formal task force was assigned to the topic. According to an interview with Peter Westlake, Manager of New Products and Services at OUC, and Eva Reyes, Project Engineer at OUC, before the team's creation, OUC was able to install 165 charging stations using grant funding. However, without the focus of a dedicated team, OUC had difficulty gaining traction in pushing EV adoption, and the previous ad hoc method of operation was prolonged.

OUC's initial priority was to ensure adequate levels of charging infrastructure, and it designed the "Charge-It" program to offset high capital costs for customers. Under the program, OUC managed ownership, installation, and maintenance costs over a seven-year lease period. Over three years, the program was developed as OUC staff were not assigned to the program full-time and only met monthly.

A typical Smaller Team with two Team Members can be summarized as follows:

- **EV Team Manager/Director:** EV charging infrastructure expert working with management to guide the EV strategy. Attends events and participates in trade organizations to learn best practices and leads regulatory efforts. Works cross-functionally with management to leverage the expertise of key departments that can help move the EV strategy forward.
- **Education and Outreach Manager:** Leads the education and outreach portion of the EV strategy. Works cross-functionally to provide key departments with the needed materials for their stakeholder and customer outreach efforts. Oversees implementation of the marketing plan, which could include customer journey mapping, EV test drives, dealership outreach, internal employee education, and website development.

4.3.2.2 Example for Medium-Size Team: Austin Energy Transportation Electrification

Austin Energy's Electric Vehicles and Emerging Technologies team has been proactive and ahead of the curve during the past years (i.e., since 2011). As a result, Austin Energy could shape the conversation and governance around an emerging and potentially disruptive technology.

Austin Energy won the U.S. Department of Energy's ChargePoint America grant in 2011 when Electric Vehicles and Emerging Technologies was formally launched with dedicated full-time staff and budget. Its first step was to develop a public infrastructure grant to foster EV growth.

Austin Energy constructed a roadmap of what it wanted to accomplish through a "brown paper exercise" facilitation technique and then established roles based on necessity and fit. Professionals with EV experience were rare at the time, so Austin Energy had to be creative in hiring. Austin Energy sought candidates who were passionate about the field, took risks in their careers, or those who had expertise in the demographics they would be serving, such as a former apartment manager for Austin Energy's multi-family program or someone with a career in the non-profit sector, such as Meals on Wheels, for its low-income program. Today, Austin Energy's Electric Vehicles and Emerging Technologies team has more than doubled compared to 2011.

Austin Energy's EV Strategy Portfolio (categorized based on a fact sheet titled "Principles for Utility Investment in Electric Vehicles," published in 2018 by the Union of Concerned Scientists[56])
1. Provide chargers where people live and work.
2. Create a network of high-speed chargers along highways.
3. Maximize benefits to ratepayers and the grid.
4. Establish fair electricity rates for EV charging.
5. Support electrification of trucks and buses.
6. Support electrification of new mobility services.
7. Ensure low-income communities benefit from electrification.
8. Create an open and competitive market for EV charging.
9. Engage stakeholders in an open and transparent process.
10. Educate the public on the benefits of electrification.

Figure 13 shows the Austin Energy EV & ET electrification team structure as of today.

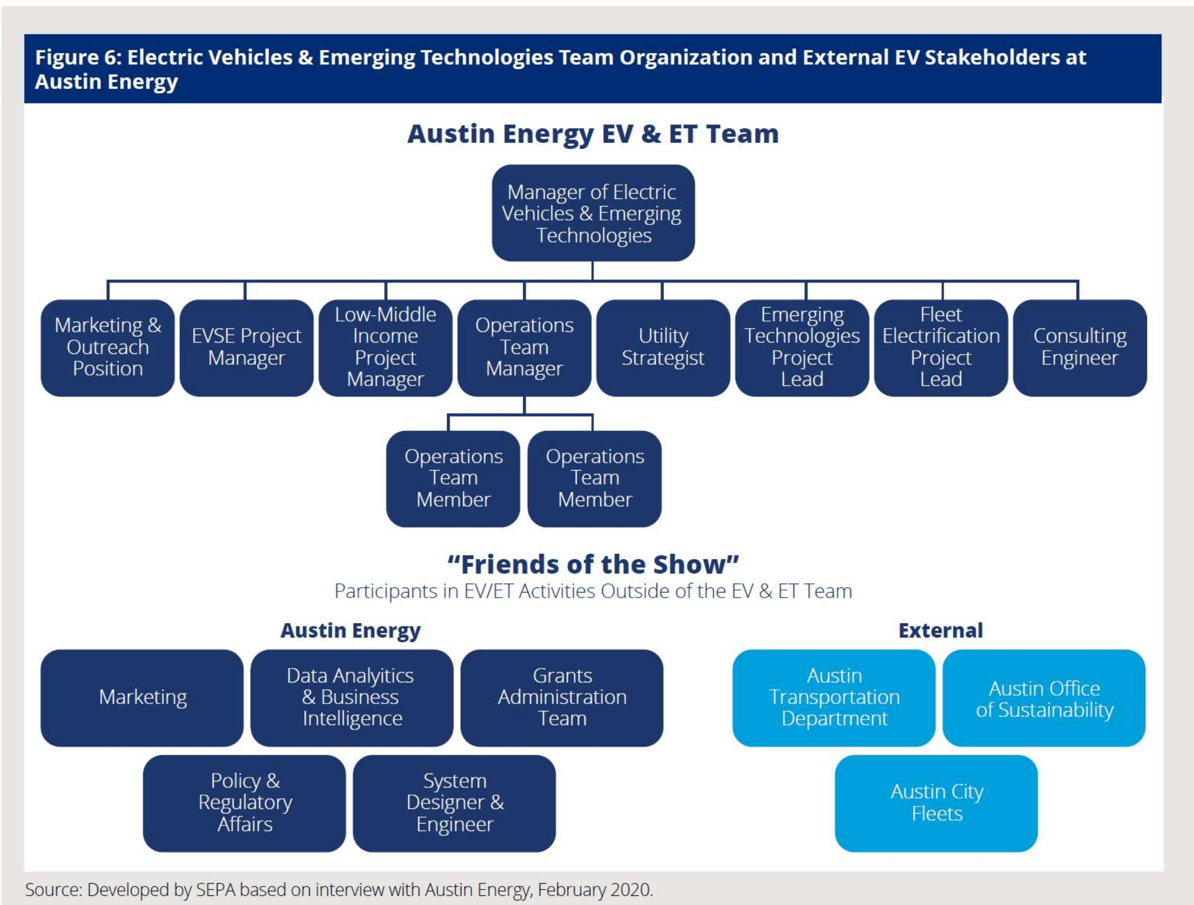


Figure 13. Austin Energy EV & ET team structure

[56] Austin Energy's EV Strategy Portfolio has more than 30 initiatives and programs. "Principles for Utility Investment in Electric Vehicles" is available at https://www.ucsusa.org/sites/default/files/images/2018/06/cv-ev-infrastructure.pdf

A typical medium-Size team with five Team Members can be accomplished as follows:

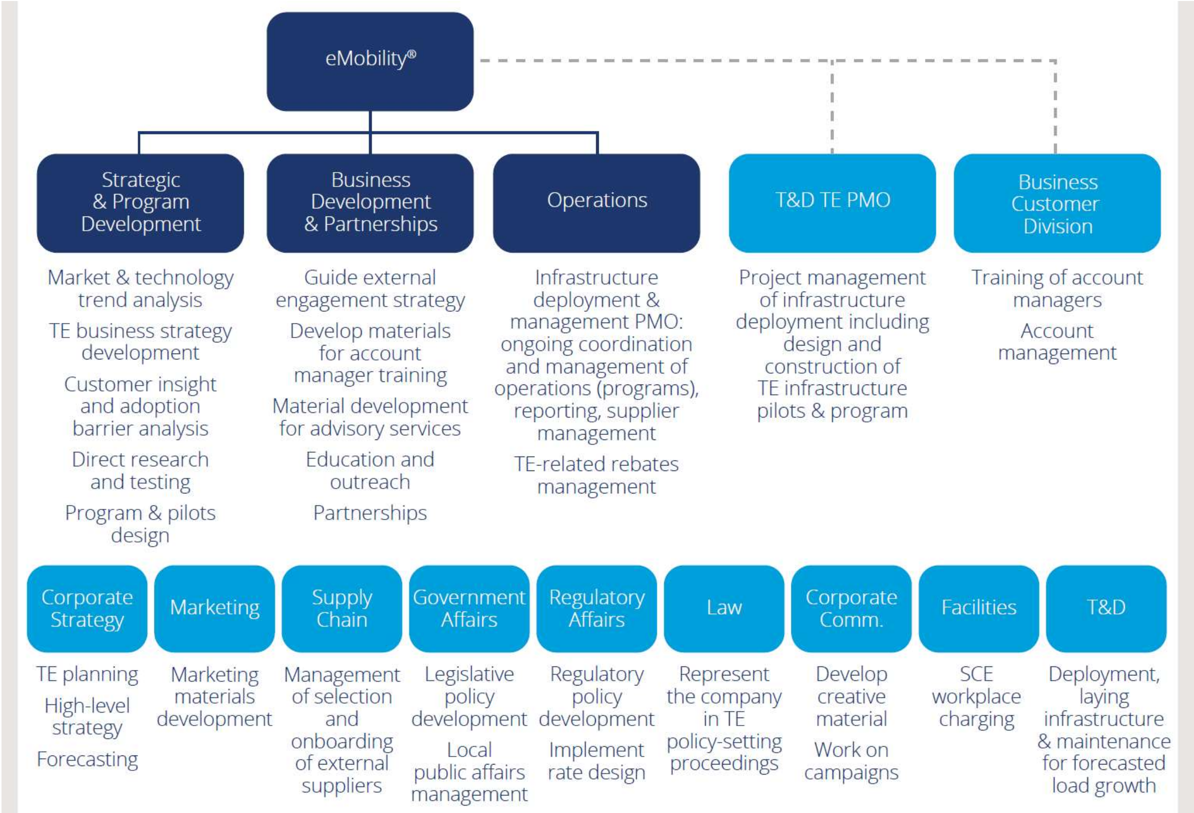
- **Same two team members as a small team plus** a growing focus on team members who can develop EV charging infrastructure programs that will gain regulatory approval.
- **EV Charging and Infrastructure Expert:** Focuses on the development of successful utility EV charging and infrastructure programs for regulatory filings.
- **Regulatory Manager:** Focuses on drafting EVSE program design elements for regulatory filings.
- **Education and Outreach Support Manager:** Supports the Education and Outreach Manager to implement the marketing plan and to oversee EV test drives, dealership outreach and internal employee educational events.

4.3.2.3 Example for Large Size Team: Southern California Edison Transportation Electrification

Over the past few decades, Southern California Edison (SCE) has operated different versions of transportation electrification teams. According to Katie Sloan, Director of eMobility® and Building Electrification, these groups were typically composed of five or six different departments working on transportation electrification and with varying degrees of centralization. Previously, transportation electrification efforts at SCE were developed in a highly decentralized fashion. That composition was adequate for SCE's Charge Ready pilot and other smaller EV-related initiatives. The project management office for the Charge Ready pilot was housed in SCE's customer programs and services department, coordinating with the sales team (in a different part of customer service), and the construction teams in the distribution organization, in addition to the regulatory, local public affairs, and corporate communications departments.

SCE undertook an effort to determine the best internal structure for a transportation electrification team when SCE sought regulatory approval for large-scale programs, including Charge Ready Transport and a passenger vehicle program expansion. The process included interviews with the various stakeholders to understand the level of workload, the current capabilities, and functions, and perceived future needs. Through those interviews, the team defined the challenges, the options, and an evaluation of how each option met the design criteria SCE wanted to optimize.

Figure 14 shows the overview of the Southern California Edison eMobility® operating model as of today.



Source: Southern California Edison, 2020.

Figure 14. Southern California Edison eMobility® operating model overview

A typical team structure for ten or more team members can be as follows:

- **Same five team members as a medium-size team member** growing focus on developing a sales and operations team for EV charging program implementation.
- **Program Manager:** Develops the sales strategy for an EV charging program. Oversees team members, bringing in sales and working cross-functionally with other departments to ensure consistent program messaging and departmental sales goals are met.
- **Sales:** It is not typical for utilities new to EV charging programs to operate sales team members. However, when implementing such programs, the role is similar to a sales role, and the goal is to help meet the program's key performance indicators through program enrollment.
- **Construction Project Manager:** Works with procurement, operations, and construction departments to manage to charge inventory and create customer EV charging infrastructure construction schedules.
- **MD/HD Charging Infrastructure Expert:** Focuses on developing medium- and heavy-duty charging infrastructure programs. Works with charging vendors to understand available technology and works with the regulatory manager to create new program filings.

- **Financial/Regulatory Analyst:** Focuses on regulatory filings and program financials, including revenue and business model analysis, as well as environmental impacts.

4.3.3 Utility-Led EV Infrastructure Programs[57]

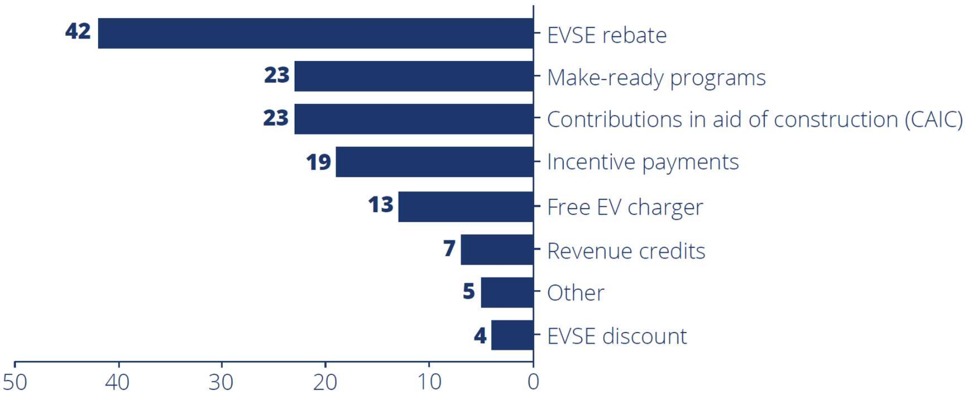
Several program options exist for utilities that intend to support EV charging infrastructure deployment proactively. Appropriate support mechanisms can be different for each utility according to market segment and regulatory requirements. Below are five different utility support options that have been utilized by utilities so far:

Make-ready Infrastructure: The utility funds, owns, designs, and installs all electrical and civil infrastructure on both sides of the meter for EV charging (including conduit, wiring, disconnects, switchgear, electrical panels, concrete pads, and the associated installation activities, including trenching, boring, repaving), except for the chargers provided by the customer. Therefore, contribution payments may be required from program participants.

- **Infrastructure rebates:** The utility funds all or part of the make-ready infrastructure via a rebate, but the project is managed and owned by the customer.
- **EVSE rebates:** The utility provides a rebate for the chargers but not for the make-ready infrastructure to support the chargers and does not own any of the infrastructures.
- **Full utility ownership:** The utility funds, deploys, owns, operates, and maintains the make-ready infrastructure and the chargers. Contribution payments may be required from program participants.
- **Utility EV fleet deployment:** The utility funds electrification efforts for its own fleet, including workplace charging for office employees and charging for utility-owned EVs. By doing so, the utility can gain valuable insight into common customer barriers, including financial issues and logistics planning.

Figure 15 indicates the summary of SEPA's 2020 Utility Transformation Challenge Survey. As is shown, the responding utilities most commonly provide EVSE rebates, make-ready programs, and contributions in aid of construction for utility-led EV infrastructure programs. In addition, most of the survey respondents provide more than one type of program incentive. (The "other" category listed in the figure includes grant programs, driver rebates, low-interest loans, funds to cover installation costs, and infrastructure co-development with the private sector.)

[57] "Utility Best Practices for EV Infrastructure Deployment" Published by: Smart Electric Power Alliance, Electric Vehicle Working Group, and Distribution Planning Subcommittee, June 2020



Source: Smart Electric Power Alliance, 2020. N=67

Figure 15. Most common utility-Led EV infrastructure program incentives

Usually, the first step in the utility-led EV charging infrastructure programs is initiated by the residential or commercial customers. Once a customer applies for a utility-funded and developed infrastructure, the utility takes the lead and involves numerous internal and external stakeholders throughout the process. The utilities may focus on spreading the chargers among the maximum number of charging sites across their boundary or choosing to have fewer site hosts and larger chargers installed at each location. In both cases, utilities often plan and launch their programs to scale in the future. Generally, the following five main steps can be counted for a utility-led EV charging infrastructure program:

1. Planning: Site prioritization (if applicable), approval requirements, vendor qualification and request for proposal development, permitting agency outreach, quality control process development, employee training, customer experience development, and new systems development (e.g., IT development or project management office development).
2. Customer Engagement: Customer marketing and outreach and continual transparency into the sales team's efforts.
3. Evaluation: Assessment and approval of the participating applications under specific parameters.
4. Design and Construction: Efficient permitting and installation of all charging infrastructure on the customer side of the meter, and/or distribution upgrades on the utility side of the meter.
5. Customer Follow-Up: Ensuring a positive customer experience through the end of the program by requesting customer feedback.

4.3.4 NREL: Integration Requirements Study[58]

4.3.4.1 Overview of the Practice

This practice entitled "Multi-Lab EV Smart Grid Integration Requirements Study" was derived by NREL in 2015. The main goal of this practice is to determine the process to analyze/evaluate the EV integration scenarios. This practice is an example of how to evaluate EV-related projects and how to analyze EV integration impacts on stakeholders. The first step is to determine the potential

[58] https://www.nrel.gov/docs/fy15osti/63963.pdf

grid-integrated EV functions. These potential values can help to understand the effect of EV integration on each type of stakeholder. The next goal is to draw a plan to enable the EV to grid integration. This practice summarizes the key factors and standards that need to be considered for preparing the distribution grids for EV integration. The key questions that the practice tries to address are as follows:

- What are the stakeholders in PEV (Plug-In Electric Vehicle) integration?
- What potential values can PEV integration provide?
- What are the key factors for enabling EV to grid integration?

Also, there are other important questions that this practice mentions as complementary efforts as follows:

- What future are electricity grid services relevant to PEVs?
- What are the potential costs and benefits of the candidate electricity grid and PEV services?
- What metrics and key performance parameters are relevant to quantifying the costs and benefits of candidate PEV grid services and technology solutions?
- What are the grid-centric and PEV-centric opportunities and perspectives?
- How might achieving these future integrated systems influence the petroleum consumption and energy benefits of the overall system?
- What might hinder PEV adoption, and what actions can be taken to enable the growth of grid-integrated features?
- What technologies need to be developed to enable vehicle grid integration (VGI)?

4.3.4.2 Key Utilized/Recommended Standards and Grid Codes

The practice identifies four main areas that need consideration as follows:

- ➢ Physical connectivity
- ➢ Communication standards
- ➢ Information standards
- ➢ Cyber security standards

- Physical connectivity standards are related to wired charging/discharging and performance criteria for wireless charging. The famous standards and recommendations in this area are as follows:
  - o IEEE 1547: Interconnecting distributed resources with electric power systems
  - o SAE J1772: PEV connector (charge coupler)
  - o SAE J3072: Interconnection requirements for onboard, utility-interactive inverter systems
  - o SAE J2954: Minimum performance and safety criteria for wireless charging of electric and plug-in vehicles
- Communications standards are generally related to DER communication protocols and physical layers. Some of the famous standards in this area are as follows:
  - o IEEE 2030.5, smart energy profile application protocol.
  - o SAE J2847/6: Wireless PEV charging standard
  - o SAE J2847/5: PEVs and customers
  - o ANSI C12.22 and IEEE 1703: Metering

- IEC 61850, Distributed Network Protocol (DNP3), and IEEE 1815: Automation of DER
- SAE J2847/3 and ISO 15118: PEV as a DER
- SAE J2847/1 and ISO 15118: AC PEV smart charging standards
- SAE J2847/2, ISO 15118, DIN 70121, and IEC 61851-24: DC PEV charging standards

- Information exchange standards
    - IEC 61970, IEC 61968, and IEC 62325: Common Information Model for DER
    - IEC 61850: Data models for DER
    - ANSI C12.19/IEEE 1377: Metering
- Cyber security standards
    - IEC 62351
    - SAE J2931/7

An example of a future hybrid energy system with integrated PEV is illustrated in Figure 16. As shown in Figure 16, there are different standards for the physical and communication layers that need to be followed.

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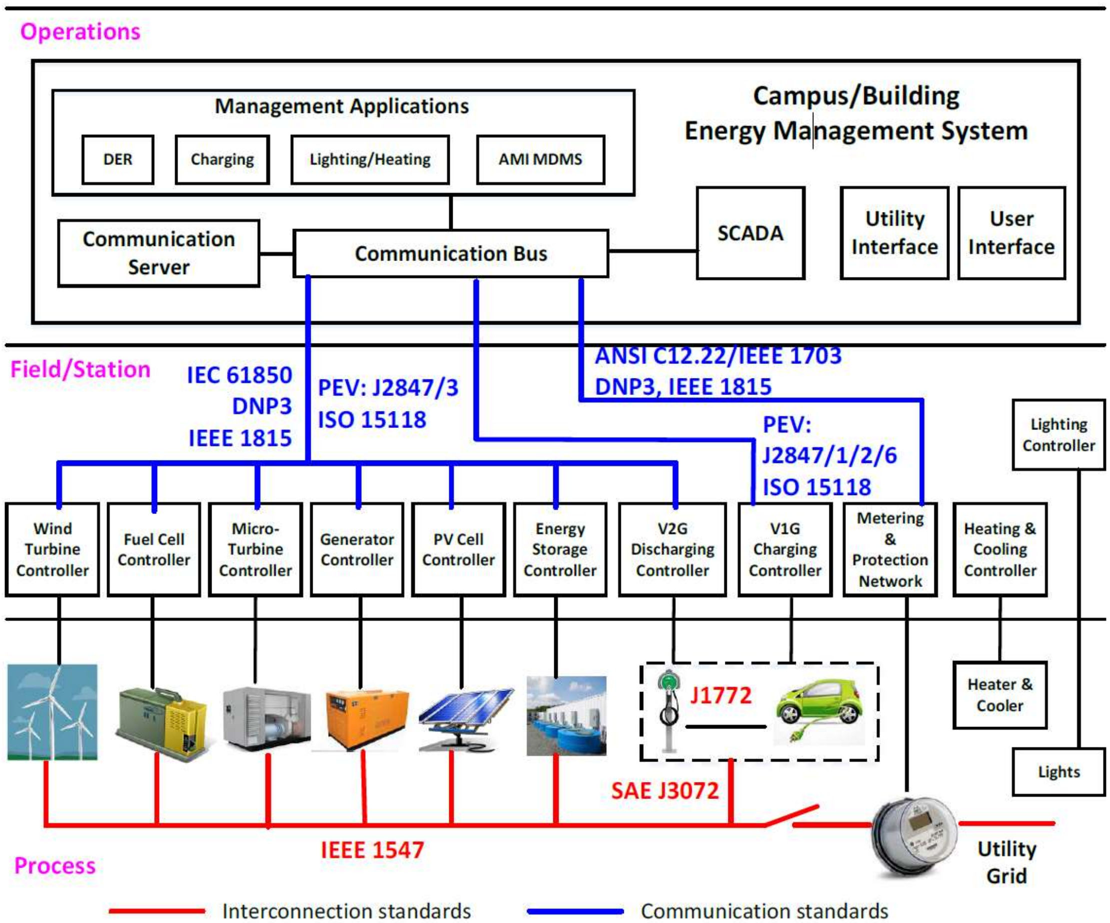

Figure 16. Major interconnection and communication standards for vehicle to grid integration projects

4.3.4.3 Process Flow

This practice aims to draw a path toward the future and provide an example of how to deal with EV integrated projects in the future. Figure17 demonstrates a high-level roadmap for PEV integration.

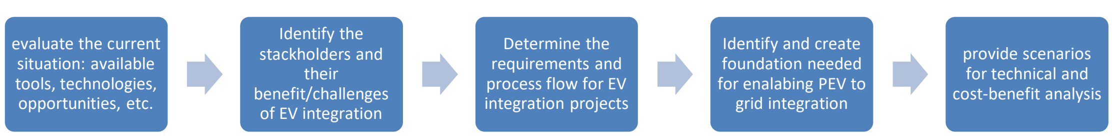

Figure17. The high-level roadmap for EV integration

Figure 18 shows a comprehensive template of PEV integration stakeholders at different levels. As is inferred, all entities that are affected by PEV integration are mentioned in a hierarchical structure. The utilities are recommended to have a similar effort and identify their PEV stakeholders and their challenges/benefits of EV integration.

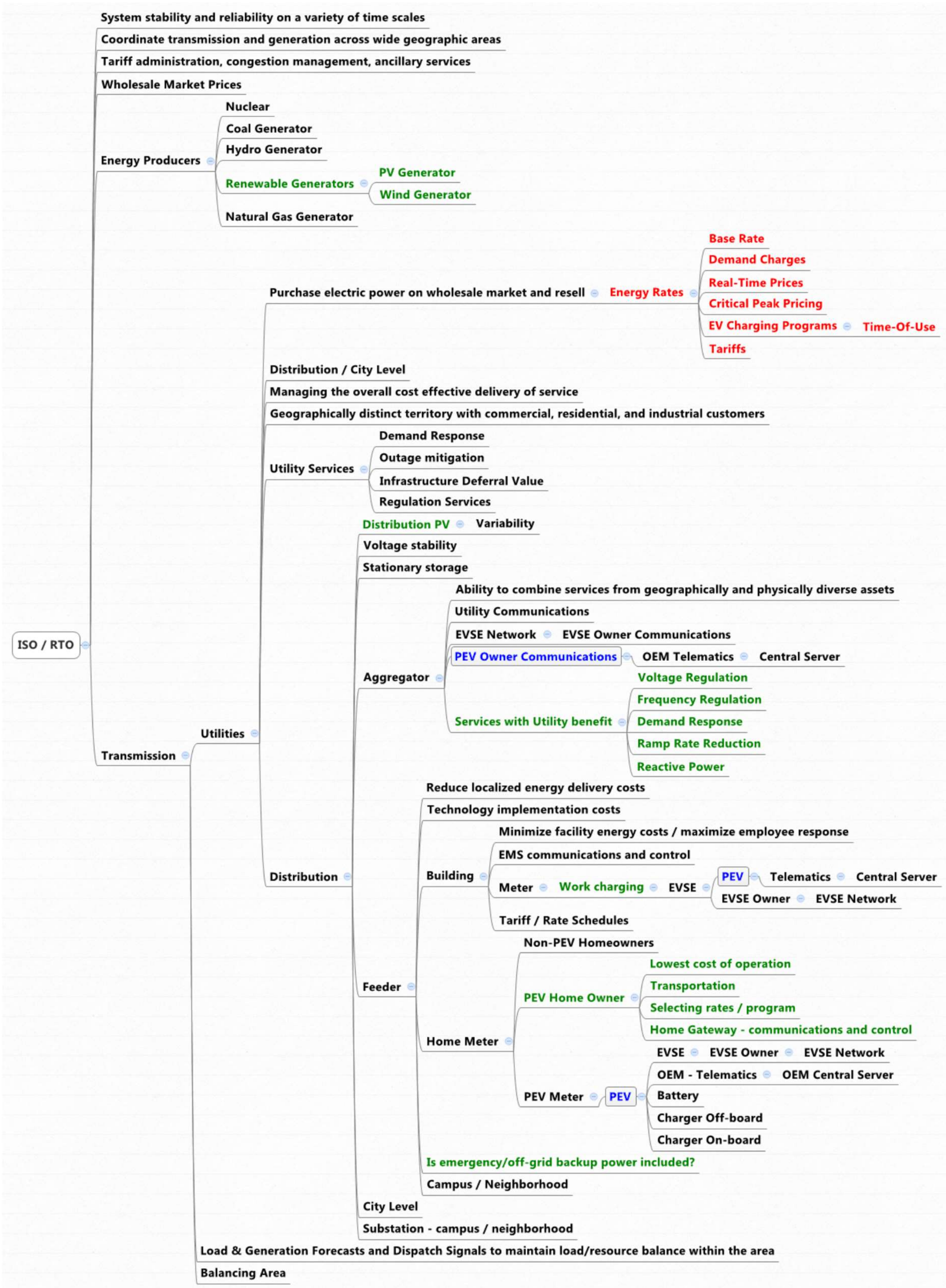

Figure 18. Stakeholders associated with PEV adoption/integration

4.3.4.4 Highlighted Results/Milestones

The integrated PEVs have several values to the grid if the charging management infrastructure is available. These values are a strong function of the regional balancing requirements, utility rate structures, generation mix, load portfolio, PEV usage profile, and battery characteristics.

A region's characteristics that affect the value proposition include on-peak/off-peak electricity rates, base electricity rates, time-of-use rates, demand charges, demand response, the proximity of the distribution system to infrastructure limits, outage impact costs, and the relative proportion of renewables generation to base-load generation. These regional characteristics lead to a need for an integrated analysis that enables optimizing the value proposition. A regional PEV charging optimization strategy may offer grid benefits.

A summary of major costs and benefits of PEV integrated projects are as shown in Table 6.

Table 6. The general cost-benefits of PEV integration

Benefits	Costs
• Avoided energy costs • Avoided marginal system line losses • Net Qualifying Capacity and Effective Flexible Capacity • Transmission and Distribution Upgrade Deferral • Ancillary Services • Fuel Price Hedge • Market Price Response • Reliability and Resiliency • Avoided Environmental Compliance Costs • Societal and Overall Economic Benefits	• Utility Costs • Administrative Costs • Interconnection Costs, borne by the Utility or General Ratepayers • Vehicle Integration Costs, at given levels of vehicle penetration.

4.3.5 Forecasting Heat Pumps and EV Loads

Western Power Distribution and UK Power Networks, two major electric providers in the UK, performed case studies in 2018 and 2014 respectively (discussed in more detail below), for different regions that forecasted the impacts of EVs and heat pumps (HPs) on the distribution system over different periods of time. Each provider modeled their load forecasts to extend out to 2050. Both studies utilize demand and generation growth forecasting on the distribution system to help determine how to best adapt to these new technologies. Additionally, each provider had recommendations for adopting distribution planning to consider the impacts of electrification.

4.3.5.1 Collaboration with Efficiency Maine Trust

Stakeholders would also like to see the utilities consider what EMT is doing to increase the use of HPs. EMT is helping to fulfill the goals of LD. 1766 by offering Maine residents and businesses special rebates and information on HPs to help them make informed decisions. In previous interviews with the utilities from the initial data collection process, both utilities have discussed collecting data from EMT to help know where devices are connected to the system. However, CMP mentioned that the data was not very granular compared to other sources. It is recommended that both electric providers work further with EMT to ensure the utilities have the data they need to accurately model and monitor new device installations.

4.3.5.2 Notification of Installation

In a 2014 report titled 'Impact of Electric Vehicle and Heat Pump Loads on Network Demand Profiles,'[59] UK Power Networks suggests implementation of a notification program, to gain and maintain visibility of electrification on the distribution network. Visibility of the system regarding HPs and EV charging locations is important so utilities can forecast the load profiles of these technologies and the charging patterns of EVs. HP load profiles were shown to be consistent with traditional factors such as ambient temperatures, however there was variation in power quality across HP manufacturers. Utilities could require or ask customers to notify their electric provider when they install EVs and HPs. Notification forms should include device type, device manufacturer, charger/pump model, and any other relevant information. Such forms would be especially helpful when large commercial and industrial customers install devices.

4.3.5.3 Short-term and Long-term Planning

Western Power Distribution's case study "Changing Load Profiles,'[60] utilized forecasting results for their system to determine adaptive short and long-term solutions to help account for emerging technologies. Short-term solutions focus on forecasting growth on the distribution system. Gaining a granular understanding of the system through forecast data is only possible by sufficiently monitoring the system. Forecasting EV patterns can be difficult as many factors weigh on the expected charging use. Influential factors include the type of charger, time of use and location (i.e., at home or at work), EV battery size, future battery sizes (larger batteries expected to result in more usage), and as EVs progress, centralized charging stations for autonomous vehicles. Heat pumps and EV load profiles will also be affected by government incentives to move towards electrification. HPs also see less diversity in usage as HP load profiles typically align with ambient temperature (little to no use in summer and high utilization in winter in the UK). Once data is collected, recommendations suggest breaking down the forecast data into five groups:

- Traditional Demand: This group would consist of residential, commercial, and industrial growth.
- Established Generation Technologies: Such generation consists of what is types of generation are already connected to the system, such as solar.
- Emerging Demand Technologies: EVs and HPs are the primary technologies in this group. EV forecasting would consist of the number of EVs, charger locations, and charging patterns, and HPs can be forecasted using ambient temperature. In the future this group would take on other major technologies that have more impact on the system.

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[59] *Impact of Electric Vehicles and Heat Pump Loads on Network Demand Profiles.* UK Power Networks. Sep. 2014. Link

[60] *Changing Load Profiles*. Western Power Distribution. Nov. 2018. Link

- Emerging Generation Technologies: This group would include any new generation technology connected to the system.
- Energy Storage: The last group consist of any energy storage connected or expected to be connected, though predicting the number of new connections for energy storage is a challenge.

For long-term recommendations, using cost benefit analysis is suggested to help determine flexible solutions, such as energy storage. Building storage sites or contracting with storage sites to provide relief when required could help with loading during peak demand. As other technologies on the demand and generation side arise and are connected to the system, it is suggested to assess these technologies through innovation projects that focus on impacts and forecasting for the distribution system.

4.4 Gap Analysis

4.4.1 CMP

CMP has taken some strides in EV adoption and electrification. This includes some scenario-based studies to forecast the system's load in different levels of EV adoption, as well as initiating pilot projects for DC fast-charging (DCFC) stations in the next few years. In addition to these efforts, there are some additional steps that can be taken to further facilitate EV and electrification adoption in the upcoming years. CMP currently has assets that exceed 100% of nameplate and that is where CMP is focusing their efforts for solutions currently. CMP has incorporated some temporal and spatial scenario-based EV load forecasts into their planning processes and should continue to refine and leverage such forecasts to better understand the impacts of electrification and ensure preparedness for load growth prior to experiencing overload conditions.

1) **Advanced EV Load Forecasting –** CMP's current EV forecasting considers relatively fixed, averaged impacts of individual EVs to the total system of feeder peak load. This approach serves as a great starting point at low penetrations and where customer behavior incentives and control structures remain relatively unchanged. Evaluating the system and feeder-level impacts of different rate structures, incentives, market signals, and potentially utility control capabilities will be critical to understanding system impacts, optimizing EV charging deployments, and minimizing the infrastructure required to support new loads. These more advanced forecasts can be used to develop and build justification for EV programs and control infrastructure improvements.

2) **Electrification Team –** As the focus on electrification and EV adoption continues to increase, establishing a focused, dedicated electrification team to act as the results owner and subject matter experts will become more critical.

3) **Electrification Hosting Capacity Map –** Similar to the Hosting Capacity map discussed previously, having a load-focused capacity map can aid public stakeholders, developers, and businesses in identifying high-capacity areas to locate larger charging stations (or more

traditional large power load growth) without requiring costly system upgrades. This can help spur growth and minimize developer uncertainty with regard to system upgrade costs.

4) **Continued Reliability Improvement**: Poor reliability was identified as one of the key concerns facing electrification programs by some stakeholders. As the distribution system becomes even more critical in support of transportation, a continued focus on reliability improvement is necessary.

5) **Continue and Expand EV Pilot Projects**: Pilot projects can identify the realistic challenges and benefits associated with the EV adoption, especially those specific to CMP's territory. CMP's pilot projects have helped them determine EV charge rates as mentioned per the Cadmus report. EV Adoption and programs can have impacts and require coordination with a wide variety of stakeholders who may not be accustomed to working closely with utilities, and pilot projects can help lay the groundwork for building such relationships and improving general public understanding.

4.4.2 Versant

Many of Versant's current planning and operational practices do not significantly incorporate electric vehicles and electrification. This appears, in part, to be a result of available distribution system capacity to absorb and integrate new loads. Versant, during the Investigation Report, identified that there is a clear requirement to start projecting the impacts of EVs, heat pumps, and electrification on the distribution system. Additionally, Versant currently offers special electric rates for customers using heat pumps during the colder months[61]. It was also noted that this is expected to occur in different forms, different penetrations, and at different times across the different areas of their service territory.

1) **EV and Electrification Roadmap –** It is recommended that Versant begin more pro-actively considering and evaluating the expected impacts of increasing EV load and electrification as part of the medium to long-term planning process. Developing a holistic roadmap will consolidate and spur expertise development in the system impacts of EVs and electrification and will help provide a clearer direction with regards to Versant's role in encouraging development in these areas.

2) **Advanced EV Load Forecasting –** Versant does not currently incorporate EVs or electrification within their planning forecasts. Evaluating the system and feeder-level impacts of different rate structures, incentives, market signals, and potentially utility control capabilities will be critical to understanding system impacts, optimizing EV charging deployments, and minimizing the infrastructure required to support new loads. These more advanced forecasts can be used to develop and build justification for EV programs and control infrastructure improvements.

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[61] https://www.versantpower.com/energy-solutions/heat-pumps/

3) **Electrification Team –** As the focus on electrification and EV adoption continues to increase, establishing a focused, dedicated electrification team to act as the results owner and subject matter experts will become more critical.

4) **Electrification Hosting Capacity Map –** Similar to the Hosting Capacity map discussed previously, having a load-focused capacity map can aid public stakeholders, developers, and businesses in identifying high-capacity areas to locate larger charging stations (or more traditional large power load growth) without requiring costly system upgrades. This can help spur growth and minimize developer uncertainty with regard to system upgrade costs.

5) **Continued Reliability Improvement**: Poor reliability was identified as one of the key concerns facing electrification programs by some stakeholders. As the distribution system becomes even more critical in support of transportation, a continued focus on reliability improvement is necessary.

6) **Continue and Expand EV Pilot Projects**: Pilot projects can identify the realistic challenges and benefits associated with the EV adoption, especially those specific to Versant's territory, which may be difficult to identify using only knowledge gained from experience in other states. EV Adoption and programs can have impacts and require coordination with a wide variety of stakeholders who may not be accustomed to working closely with utilities, and pilot projects can help lay the groundwork for building such relationships and improving general public understanding.

Table 7 summarizes identified gaps for both utilities regarding EV and electrification.

Table 7. Summary of gaps for both utilities regarding EV and electrification

Versant	CMP
EV and Electrification Roadmap	Advanced EV Load Forecasting
Advanced EV Load Forecasting	Electrification Team
Electrification Team	Electrification Hosting Capacity Map
Electrification Hosting Capacity Map	Continued Reliability Improvement
Continued Reliability Improvement	Continue and Expand EV Pilot Projects
Continue and Expand EV Pilot Projects	

5 Advanced Distribution Management System (ADMS)

Modern electric power system needs from consumers and other stakeholders have led many utilities to implement an advanced distribution management system. ADMS software is utilized to integrate various utility systems, software, and data sources. The ADMS integration provides utilities with a heightened level of awareness and control over their distribution systems through available functions such as automated restoration, optimal power flow, state estimation, automated fault location, isolation, and service restoration (FLISR), conservation voltage reduction (CVR), peak demand management; and Volt/VAR optimization. Unifying various systems and data also allows utilities to transition from more manual processes and isolated software systems to a system with real-time data, automated processes, and rich integrations. Another management system that many utilities are adopting and can be integrated with ADMS is a DER Management System (DERMS). DERMS systems allow for operation, data collection, and awareness for DERs connected to the grid. This section provides regulatory requirements, stakeholder needs, industry best practices, and gap analysis for the implementation of ADMS.

5.1 Stakeholders Needs

This section provides one or a group of involved stakeholders' concerns, ideas, opinions, and suggestions which are taken from "Maine DER Roadmap- Stakeholder Feedback" report directly and summarized in this report. While this process reached a diverse group of stakeholders, it does not reflect all stakeholders engaged in these issues. The goal of this work is to capture the broad concerns and diverse visions among energy businesses, elected officials, system operators, and advocates in an accessible, clear and anonymous summary. No attempts were made to verify any of the factual assertions in the stakeholder comments, except where footnoted. No statement has unanimous agreement from stakeholders – there is a wide diversity of views on the sources, severity and solutions to the challenges of DER integration, and no statement in this report should be attributed to any specific stakeholder. Even when "many stakeholders" raise a concern or support a position, this should not be read to suggest that even a majority of stakeholders hold such a belief.

- **Stakeholders Concerns**

  - Stakeholders pointed to smart meters as investments that have not borne significant fruit for ratepayers - they are interested in seeing more transparency in electricity costs and more sophisticated use of smart meters to enable and encourage demand response or otherwise provide grid and customer services.
  - There is concern that utility bills are not clear enough to consumers, especially paper bills for people who do not have reliable internet access.
  - Data sharing is a key need both for identifying opportunities for efficiency improvements and actualizing customer savings. Lack of energy data was seen as an existential obstacle to demand response, especially in commercial buildings with multiple tenants.
  - Maine utilities are not using state-of-the-art modeling or system management tools, which would help resolve data access concerns and improve operational efficiency. These investments would improve certainty for all decisions around grid modernization and DER integration and should be prioritized.
  - There is enthusiasm among stakeholders for the Non-Wires Alternatives (NWA) coordinator position with the MPUC. Stakeholders noted that utility data access has been a roadblock for the NWA coordinator.

- **Stakeholders Suggestions**

  - Stakeholders raised concerns about sufficient staff resources at the PUC for the effort but felt the direction of their work was good. One stakeholder called for a grid planning division at the PUC to support grid modernization and resource integration.
  - Stakeholders suggested that steps to enable demand response and load shaping would be key to low-cost decarbonization. Rate design to encourage demand response was a priority, as was utility work to enable automation and aggregation capabilities.
  - Stakeholders mentioned that to be economically viable, demand response aggregation needs the ability to shift significant load without major cost or inconvenience to consumers. Demand response aggregators have fixed costs per participant, so the value of controlling load has to be high. For instance, some stakeholders believe batteries and EVs offer greater demand response value than highly efficient heaters.

5.2 Best Practices

5.2.1 An Introduction to ADMS

A conceptual ADMS architecture is shown in Figure 19. As can be seen from Figure 19, ADMS can have various interpretations and functionalities depending on the identified goals and budget limitations. The core part of an ADMS is the integration of an outage management system (OMS), distribution management system (DMS), and distributed energy resources management system (DERMS). However, ADMS can be implemented to be able to incorporate the entire distribution system operations, planning, and integrations of new technologies such as electric vehicles (EVs) and demand response (DR). Examples of ADMS integrations with various distribution system components are as follows.

- Integration with AMI meters will enable the grid's sensing capabilities to notify the utility when customers are experiencing an outage, flickering lights, open neutral, or power quality issues.
- Integration with DERMS can provide demand-side DR/DER flexibility for local grid services like voltage management, reserve capacity, power quality, and frequency.
- Integration with existing energy management system (EMS) for coordination with transmission operations.
- Integration with customer information system (CIS) and customer relationship management system for customer data.
- Integration with grid planning and interconnection applications to support hosting capacity analysis and inform grid model characteristics for power flow and DERMS; and,
- Integrations with third-party data providers such as wind and solar forecasting vendors.

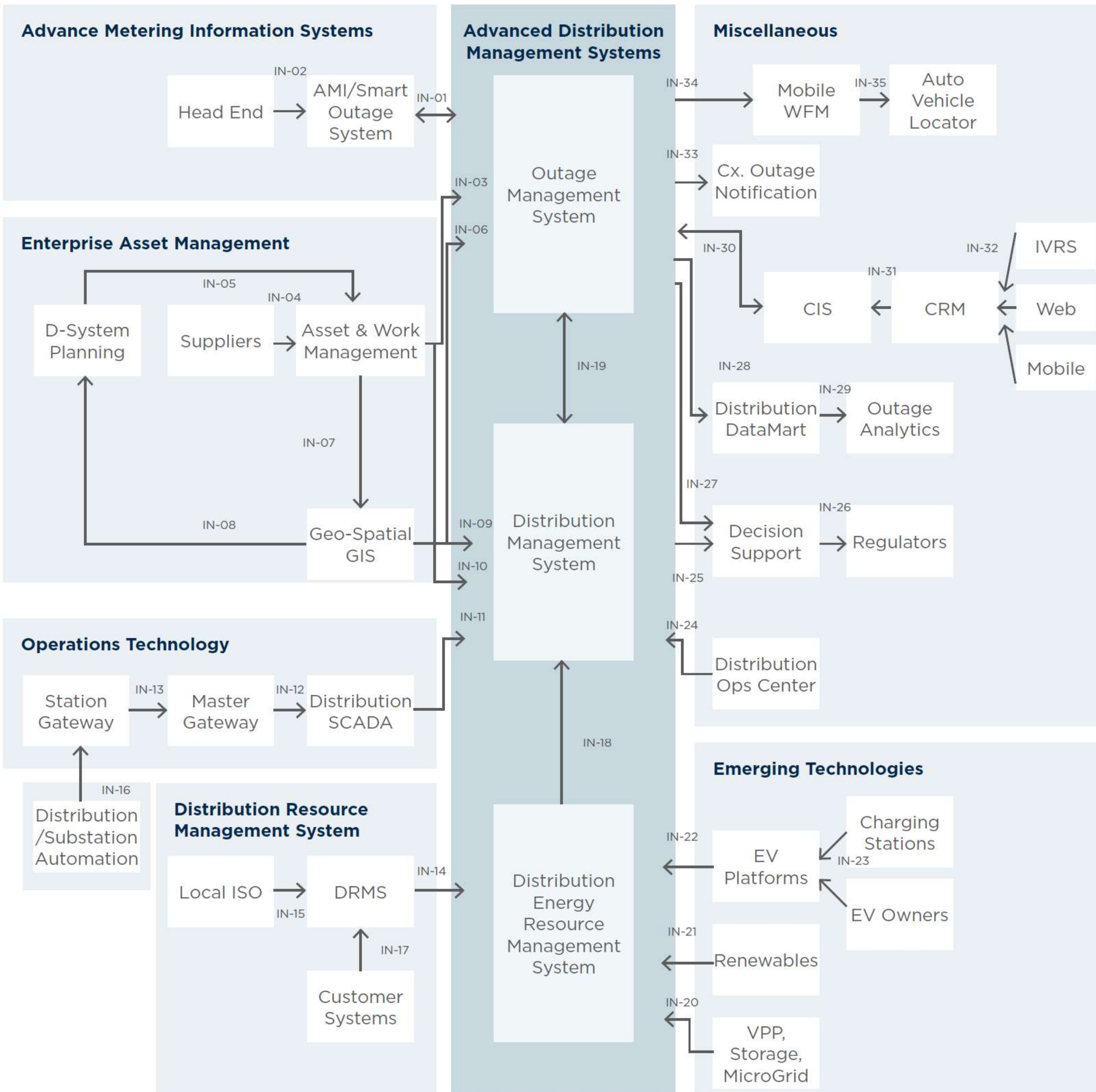

Figure 19. A conceptual architecture for an ADMS[62]

5.2.2 Austin Energy ADMS Implementation

Austin Energy, the eighth largest community-owned utility in the U.S., serves more than a million residents in and around Austin, Texas. The utility's mission was to convert "big data" into useful information, provide more reliable customer service, and improve energy efficiency, in part by creating a safer, stronger, more resilient power grid. Austin Energy chose an EcoStruxure solution, which is Schneider Electric's ADMS product.

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[62] https://www.westmonroe.com/perspectives/resource/guide-to-advanced-distribution-management-deployment

Prior to rolling out the ADMS, Austin Energy conducted a pilot to assess technical feasibility as well as the costs and benefits of installing such a system. The pilot comprised monitoring and control of various distribution automation devices over a mesh radio network. Simultaneously, the utility modeled a two-substation area to assess the validity of the GIS model, as well as the model's ability to communicate the data needed to calculate and solve load flow and fault current. Both models produced positive results.

Austin Energy's distribution automation architecture is shown in Figure 20. The business drivers for ADMS development are as follows[63].

- Capitalizing on DMS intelligence paired with a traditional OMS prediction engine to determine fault location and expedite restoration; including leveraging Austin Energy's fully deployed smart meter assets
- Deployment of a highly reliable system (99.98% Availability)
- Need for a single HMI[64] with a common database model to reduce the number of systems/screens operations staff have to interact with while increasing situational awareness and decreasing Operator stress/fatigue
- Reduce future training needs by reducing the number of systems
- Fully functional Dispatcher Training System (DTS)/training simulator
- Operational engineering analysis tools integrated into ADMS to provide real-time support of Operators
- Maintain and support one back-end system
- Better manage the effect of severe weather

[63] https://vdocuments.net/austin-energy-adms-implementation.html
[64] Human machine interface

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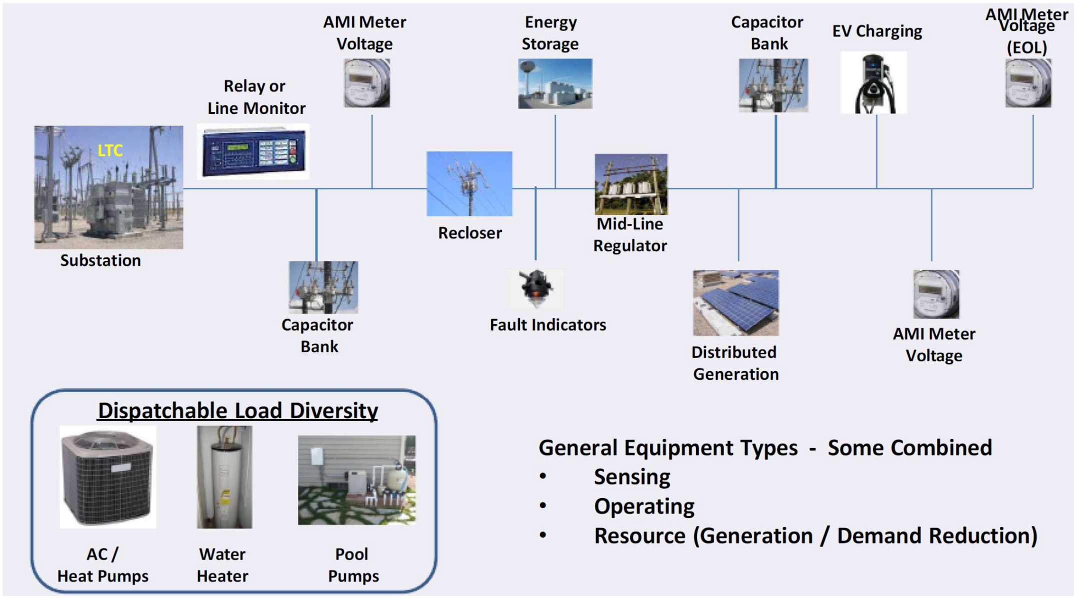

Figure 20. Austin Energy's distribution automation architecture[65]

The enhancements Austin Energy was initially looking for are summarized in Table 8.

Table 8. Anticipated enhancements for ADMS development by Austin Energy[48]

Enhancement	Functionality Delivered
Integrated Voltage Var Control (IVVC)	Optimize the system, reduce power losses, and apply conservation voltage reduction to reduce demand
Fault Location, Isolation, and Service Restoration (FLISR)	Assist locating faulted equipment, automatically isolate, and expedite power restoration by re-routing power and sending crews directly to area needing repair
State Estimation and Load Flow	Increase operator situational awareness and minimize future costs to expand distributed grid intelligence
Leverage other Intelligent Initiatives	Further optimize the electric system, including Distribution Automation (DA) and Advanced Metering Infrastructure/Automatic Metering Reading (AMI/AMR)

The implementation of the new ADMS aimed to have the following level of interfaces with various distribution system sub-systems shown in Figure 21.

[65] https://vdocuments.net/austin-energy-adms-implementation.html

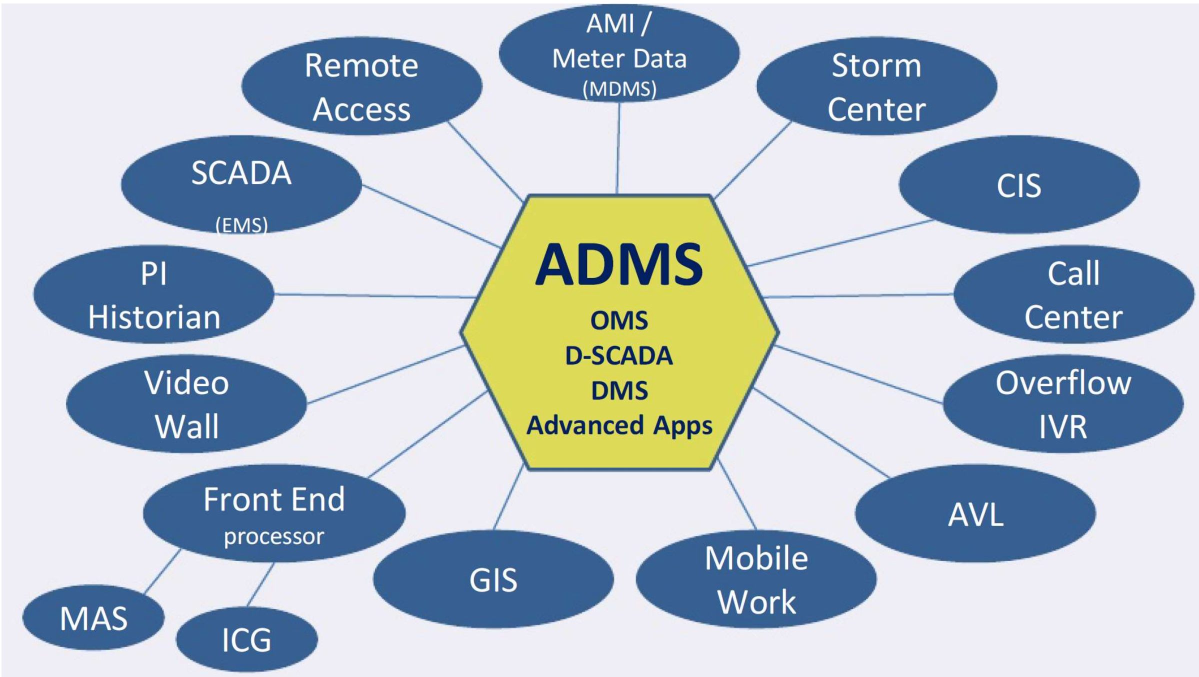

Figure 21. Austin Energy's ADMS interfaces[66]

The ADMS system combined DMS, OMS, and Distribution Supervisory Control and Data Acquisition (DSCADA) system functionality into one system. By fully integrating both demand response and distribution resources into the operations of the distribution system, Austin Energy was able to enhance its communications to customers regarding the status of outages.

The reported benefits from the implementation of the ADMS system can be summarized as follows[67].

- By implementing the ADMS and using its functionality, Austin Energy successfully managed Austin's network with improved visibility and control through the Texas summer storm season in 2017.
- Operators now depend on a fast, highly reliable system, with access to more real-time information on the same system, such as load flow information, locations of crew vehicles, and SCADA and OMS information.
- The utility now has access to a dispatcher training simulator for the ADMS, which provides operator training for critical scenarios.

[66] https://vdocuments.net/austin-energy-adms-implementation.html
[67] https://www.se.com/ww/en/download/document/998-1284-06-08-15AR0_EN/

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5.2.3 GridNode DER Management Solution[68]

5.2.3.1 Overview

The GridNode DER Management solution includes the control and automation functions to manage Active and Reactive Power, Power Factor, and Voltage at the point of interconnection for the Renewable Energy Resources. Figure 22 shows the GridNode key drivers.

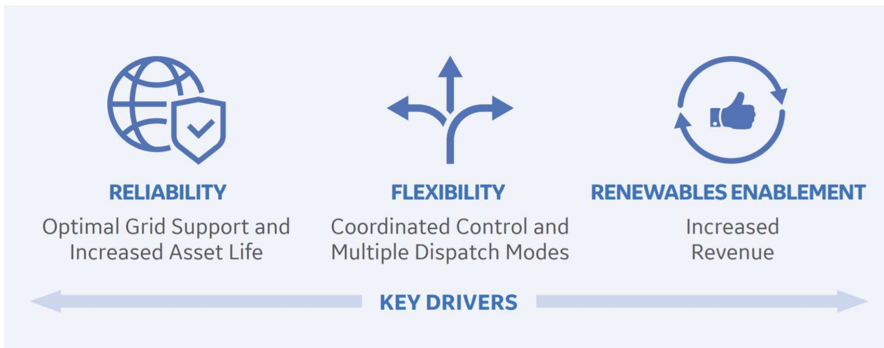

Figure 22. GE's GridNode key drivers

- **Key Benefits**
  - **Improve reliability** by exploiting renewable generation capabilities in order to provide optimal support to the grid.
  - **Ease of deployment** by utilizing GE's configurable GridNode DER Management Solution.
  - **Increased revenue** through equitable dispatch across renewable generation assets and providing the capability to provide ancillary services to the grid such as Reactive Power support.
  - **Energy cost reduction** through a solution that can efficiently manage, optimize and integrate low-cost renewables onto the grid.
  - **Life extension** by reducing the number of operations on distribution level voltage transformers and capacitor banks through the optimal and flexible dispatch of renewable generation assets.

5.2.3.2 Architecture

GE's GridNode DER Management solution monitors and controls renewable energy assets from the point of interconnection (POI). Capabilities include being able to receive a set-point (P, Q, V, or PF) for the POI and control the connected DER assets to comply by dispatching them equitably, taking into account the network parameters (Figure 23).

[68] https://www.gegridsolutions.com/powerd/catalog/gridnode-der-management.htm

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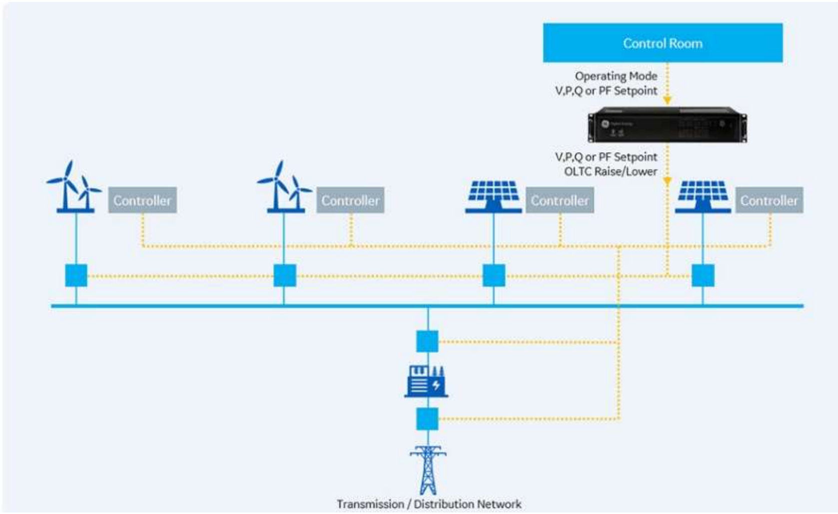

Figure 23. GridNode DER Architecture

5.2.3.3 Functions

- Dispatch Modes

GridNode: DER Management Solution, has the capability to dispatch commands to the connected DERs in one of the modes below in order to achieve the provided setpoint at the point-of-interconnection (POI).

  - VOLTAGE
  - REACTIVE POWER
  - ACTIVE POWER
  - POWER FACTOR

The GridNode DER Management Solution considers the network limits and parameters and the individual DERs capacities and constraints when dispatching commands to each DER. In addition, the GridNode solution is capable of controlling a tap changer if required to obtain the desired value at the point of interconnection (POI).

- Control Capabilities
  - EQUITABLE DISPATCH
    - Ability to dispatch the setpoint provided by the operator or DMS in an equitable manner, considering the system limits, across all DER assets.
  - RAMP-RATE CONTROL
    - Ability to control the ramp rate of the intermittent renewables connected to the system.
  - FEEDER CONTROLS
    - Ability to integrate feeder controls and monitoring into the solution.
  - VOLT-VAR CONTROL
    - Ability to issue, raise, and lower commands to OLTCs, when the DER capabilities are exhausted.

5.2.3.4 Hardware Specifications

GridNode DER Management runs on the GE Power Gateway (GPG) hardware platform.

GPG Hardware Specification

- Certification: IEC 61850-3, IEEE 1613, CE, FCC Class A, UL, CCC
- Mounting: 2U/19" Rack mount
- System Design: Fanless, with no internal cabling
- OS Support: RTOS VxWorks and Windows Embedded.
- Power Supply: Redundant 100 ~ 240 VAC (47 ~ 63 Hz) DC: 100 ~ 240 VDC DC: 48VDC with isolation protection.
- PRP & HSR Ethernet redundancy.

Two expansion slots to increase serial and Ethernet port types and quantity.

5.3 Gap Analysis

Considering the fact that ADMS is a relatively new technology and requires significant investments, the prudency and timing of ADMS deployment requires careful consideration and a thorough understanding of the expected use cases and benefits. This is even more true in the case of DERMS systems, where the details of intended functionality and benefit cases can be somewhat nebulous to pin down and analyze at this stage of industry adoption. With that said, the promise and intended functionality of ADMS and DERMS systems is likely to be a critical enabler to successful management of increasingly complex distribution systems. In this section, some of the areas related to distribution system management are discussed that can be improved to better serve distribution system users as needs materialize and software platforms continue to mature.

5.3.1 CMP

CMP will be deploying the Spectrum ADMS platform in 2022 and has identified future plans to incorporate DERMS functionality for improved DER management. The gaps and opportunity areas identified below are based on the initial deployment capabilities identified by CMP for 2022.

1) **Data and Model Quality –** One of the core promises of an ADMS system is improved situational awareness and advanced applications that take advantage of available data and estimate non-metered parameters through functions like power flow and forecasting. As discussed previously, CMP's existing data quality issues related to phase information and customer to transformer mapping are significant hurdles in accurate power flow and modeling efforts. The planned Grid Model Enhancement Project will remedy these issues, but the Q1 2026 system-wide expected completion date means that data quality will continue to be a limiting factor for at least some circuits for several years to come. Maintaining focus on quality improvement and utilizing ADMS advanced functions where data quality is sufficient to support them should improve overall ADMS system utilization and, consequently, operational outcomes for customers. CMP's stated plans to deploy automated grid restoration following the successful integration with the OMS system is a good example of such utilization, as AGR does not require power flow models to function.

2) **Mobile Integration -** Another issue seen today is that OMS is not integrated with a mobile data system, which would allow for improved information provided to and received from field crews to improve troubleshooting and restoration-time estimation. CMP mentioned that this functionality is under study, with an expected go-live by 2024.

3) **Utilization of Smart Meters for Demand Side Management –** The AMI functionality that CMP is currently utilizing include collecting power consumption, momentary outage detection, remote connect/disconnect, outage detection, billing, voltage optimization (pilot), theft detection, on-demand reads, and power flow (future plan). With the expected proliferation of DERs and EVs in distribution systems in Maine, evaluating the capabilities of smart meters or AMI to include demand side management (DSM) programs in distribution system planning is of interest by stakeholders. It is worthwhile to mention that implementation of DSM programs is dependent upon the future developments of technology to enable such programs, as some past pilot projects have identified interoperability challenges that have limited scalability.

5.3.2 Versant

1) **ADMS / DERMS Deployment –** Versant does not currently have an ADMS or DERMS system deployed, though it was one of the investments discussed in its most recent rate case. As discussed previously, ADMS systems can be leveraged to improve system integrations, streamline operations, improve situational awareness, improve reliability, and optimize power flows. Future deployment of an ADMS and eventually DERMS system will become necessary in order to effectively manage the increasingly complex distribution system and unlock additional value from communications and control infrastructure.

2) **Utilization of Smart Meters for Demand Side Management –** The AMI functionality that Versant is currently utilizing and is planning to utilize with their 2022 AMI upgrade include collecting power consumption, voltage optimization (pilot), remote connect/disconnect, outage detection, theft detection, billing, load flow, and on-demand reads. With the expected proliferation of DERs and EVs in distribution systems in Maine, evaluating the capabilities of smart meters or AMIs to include demand side management (DSM) programs in distribution system planning is of interest by stakeholders. It is worthwhile to mention that implementation of DSM programs is dependent upon the future developments of technology to enable such programs, as some past pilot projects have identified interoperability challenges that have limited scalability.

Table 9 summarizes identified gaps for both utilities regarding ADMS.

Table 9. Summary of gaps for both utilities regarding ADMS

Versant	CMP
ADMS / DERMS Deployment	Data and Model Quality
Utilization of Smart Meters for Demand Side Management	Mobile Integration
	Utilization of Smart Meters for Demand Side Management

6 Integrated Distribution Planning (IDP)

6.1 Regulatory Requirements

6.1.1 MPUC Rule 407 Chapter 320 requirements:[69]

- **Purpose:** Chapter 320 establishes system standards and associated protocols for record-keeping and reporting requirements for Transmission and Distribution Utilities.
- **Summary:** This chapter provides quality of service standards, nominal and service voltage requirements, provisions on how and when to report service interruptions, and metering requirements for T&D utilities.
- **Impact on Distribution Utilities:** Standards and requirements in this chapter create the foundation of how the system and basic organization of the planning and operations teams should function.

6.1.2 Public Law No. 1181 Requirements:[70]

- **Purpose:** PL 1181 An Act to Reduce Electricity Costs Through Non-Wires Alternatives, for public utilities, including T&D.
- **Summary:** This act establishes how utilities should approach non-wire alternatives, non-transmission alternatives, behind-the-wire alternatives, and the processes for how projects will be assessed, and the data needed to be provided for assessments. Additionally, there is a small transmission and distribution projects section that discusses how planning groups should approach planning for projects less than $5 million on infrastructure capable of operating at less than 69kV.
- **Impact on Distribution Utilities:** This act provides utilities with guidelines on how to approach non-wire alternatives, which should be utilized by utility planning teams for T&D.

6.2 Stakeholders Needs

This section provides one or a group of involved stakeholders' concerns, ideas, opinions, and suggestions which are taken from "Maine DER Roadmap- Stakeholder Feedback" report directly and summarized in this report. While this process reached a diverse group of stakeholders, it does not reflect all stakeholders engaged in these issues. The goal of this work is to capture the broad concerns and diverse visions among energy businesses, elected officials, system operators, and advocates in an accessible, clear and anonymous summary. No attempts were made to verify any

[69] Chapter 320: Electric Transmission and Distribution Utility Service Standards. MPUC. May 6, 2020.
[70] LD No. 1181 An Act to Reduce Electricity Costs Through Non-Wires Alternatives. 129th Maine Legislature. Jun. 6, 2019.

of the factual assertions in the stakeholder comments, except where footnoted. No statement has unanimous agreement from stakeholders – there is a wide diversity of views on the sources, severity and solutions to the challenges of DER integration, and no statement in this report should be attributed to any specific stakeholder. Even when "many stakeholders" raise a concern or support a position, this should not be read to suggest that even a majority of stakeholders hold such a belief.

- **Stakeholders Concerns**

  - Maine's electric rates are among the highest in the country, and Maine ratepayers have among the highest energy cost burdens. There is concern among stakeholders that if electricity prices are seen as rising or excessively volatile, ratepayers will be slow to electrify vehicles, building heat, water heating, and other appliances.
  - The loss of local generation is a concern for stakeholders, especially in the NMISA region. Questions arose of how to attract investment in the generation that will support local resilience and reliability.
  - Consumer trust of Maine's IOUs is generally low, though stakeholders indicate that it is growing with improved communications and service. The combination of poor reliability and high electricity costs can lead to skepticism about the value of further investments by utilities.
  - Utility resilience strategies seem to hinge on vegetation management. Stakeholders understand the value of this work but are also looking for flood resilience along the coastline and planning for extreme weather events based on the trajectory of climate change, rather than planning exclusively based on historical climate and weather patterns. Utilities report that operational improvements are underway to support both reliability and resilience.
  - There is concern that utilities are overly reliant on familiar methods and do not consider alternative strategies that could better solve problems at a lower cost.
  - Poor reliability is seen as an obstacle to electrification and electric vehicle adoption. If early adopters see poor results, adoption will be slowed.
  - The grid in Maine is not considered robust enough by some stakeholders to absorb significant new distributed generation or building and vehicle electrification, and many expect significant upgrades to be necessary.
  - The distribution grid will need substantial investment to support broad electric vehicle adoption.
  - Storm recovery costs are rising as storms become more frequent and cover a wider area. If multiple states are affected, states are not able to exchange recovery resources in times of need. Stakeholders pointed to a need for better planning, such that emergency conditions are anticipated, and affordable solutions are ready to go. However, since utilities are currently able to recover costs in emergencies outside of their normal rates, they are not encouraged to find the most cost-effective solutions.
  - Climate accounting is difficult, but with legislative goals in place, it must be accurate. There was concern that sustainability efforts would simply move energy-intensive industries to other countries, creating a net negative impact on climate change globally.

- Time of Use (TOU) rates have very low adoption in Maine - stakeholders see the opportunity for these rates to be marketed more successfully while acknowledging that some customers would face undue burden if forced to adopt a TOU rate. There are questions about whether a TOU rate makes sense if houses do not have smart appliances which can control electricity demand. With high electrification and smart appliances, as well as greater variability in the timing of low-cost electricity as renewable penetrations increase, it may make sense for rates to be more dynamic than TOU.
- Utility investment is slowed by a perceived lack of alignment among goals for ratepayers, generation developers, the PUC, and the legislature. Widespread education on the pathways to Maine's clean energy and electrification goals and a clear prioritization of goals with roadmaps would facilitate ratepayer buy-in, utility investment, and development.
- Coordination and collaboration among utilities, the MPUC, and the legislature is seen as a potential driver of faster and more efficient progress towards cleaner electricity and improved electric service.
- In terms of regulation and governance, stakeholders acknowledged significant uncertainty in technology cost-curves. Stakeholders encouraged policymakers to enable evolution in electricity generation and delivery but not dictate technology approaches. Some stakeholders suggested setting clearer standards and metrics for utilities, with penalties if they fail to meet them.
- Some stakeholders see the current IOU regulatory paradigm as unacceptable. They see public power as a structure more responsive to ratepayer priorities, with a higher return on investment for ratepayers. One stakeholder suggested that a for-profit entity should be compensated solely on grid performance, with low-cost public capital to finance operations. That stakeholder sees performance-based ratemaking as inefficient under the current monopoly paradigm - only adding to utility profits without showing marked improvements. The stakeholder also noted that the Non-Wires Alternatives Coordinator would, in part, provide competition to utility proposals, leading to better results for consumers.
- There were also concerns about large energy customers choosing to use microgrids to island from the grid due to reliability or cost concerns, shifting the cost burden to other ratepayers. On a longer timescale, a stakeholder raised concern that grid defection would become commonplace as DER technology becomes more accessible if the utilities are not seen as trusted partners by ratepayers.
- Relatively expensive and unreliable electric service is also seen as a reason that businesses would choose not to move industry to Maine or would move industries out of Maine. The referendum vote against the New England Clean Energy Connect line was seen as a dangerous signal to business and investors, suggesting that Maine is a risky place to do business.
- Overall utility profitability has remained very high over decades, as was shared through a graphic from U.C. Berkeley Energy Institute at Haas School of Business by a stakeholder. Stakeholders are concerned that utilities will protect their balance sheets at the expense of improved service or more ambitious timelines for clean energy integration.
- Community buy-in for major energy infrastructure is very helpful. Stakeholders called for equitable and holistic engagement with communities - not just convincing the local

officials of the value of a project but proactively reaching out to the community broadly and listening to their concerns and needs. The question of who pays for upgrades is top of mind for many stakeholders, especially if the system value is speculative and based on projections.

- Maine's geography, dispersed population, and climate leads to unique reliability challenges. There is an uneven understanding of these challenges - while some customers understand that improving reliability could lead to high costs, others expect better service without increased rates.
- Stakeholders reported that frequent power outages have led many Maine customers to make their own reliability investments, depending on their means. Those who can afford them will have backup generators or pellet stoves, and newly constructed homes will sometimes come with a generator. Even those who transition to a heat pump are likely to keep their oil heaters in place as a backup.
- Utilities see reliability and resilience investments as a high risk of being deemed imprudent by PUC. Other stakeholders recognized this as a challenge.
- Efficiency Maine Trust (EMT) is seen as a trusted and effective agency. Stakeholders support EMT's approach to encouraging traditional efficiency measures and pointed to EMT pilot projects on demand response as a productive step in Maine's energy transition.
- The definition of "energy efficiency" is changing to include more system-level measures such as energy storage and demand response. One stakeholder suggested incorporating more data-driven efficiency interventions and verifications and more market-based or performance-based funding schemes. Transactive energy is also an area of interest for some stakeholders, though pilot projects are needed.
- Stakeholders also did not see a clear path for engaging large industrial customers in demand response programs. While some industrial customers have combined heat and power or other onsite generation, no stakeholders knew of those customers acting as net generators for the system.
- System operators are expecting that electrification of heating and the decrease in electric vehicle efficiency in cold weather will eventually lead to a winter peak in electricity demand rather than the current summer peak.
- The retirement of the Pilgrim nuclear generator in Massachusetts is seen as an obstacle to low-cost decarbonization in Maine, as is the referendum against the New England Clean Energy Connect transmission line.
- There is concern that ratepayers will bear a significant cost burden due to sustainability policies, especially in rural regions.
- Equity is a challenge in Maine, in part due to stark differences between Maine's more densely populated and affluent coastal communities and more rural and economically depressed inland regions. Some stakeholders are concerned that the needs of wealthier ratepayers will come before poorer communities and ask for utilities to use an even hand in their dealings.
- Stakeholders are interested in seeing clear affordability and equity metrics from utilities. Some also want to see models of how increasing solar generation will affect the system and what other investments, such as storage, will be required. Ownership models for storage could help improve equity and focus benefits to the ratepayer rather than developers.

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- The Net Energy Billing program was raised as an area of inequitable incentives, though the value of the program to municipalities was raised as a measure of community value. However, NEB customers should still pay for upkeep and expansion of the distribution grid. Several stakeholders shared concern that the minimum monthly bill was too low to support the grid infrastructure, though some NEB customers perceive the minimum bill as a penalty. Stakeholders pointed to low NEB participation by low-income customers, leading to low-income ratepayers subsidizing high-income ratepayers' electricity service. The current NEB policy was also seen as discriminatory to other resources besides solar.
- Maine has the oldest population in the country. Fixed incomes make increasing, or fluctuating power prices a major concern, and life-sustaining medical devices make electric reliability potentially a life-or-death matter.

- **Stakeholders Suggestions**

- Moving to more efficient electric devices was also seen as an opportunity to reduce costs for consumers.
- Stakeholders noted that while Maine ratepayers usually understand why electric reliability is difficult to achieve in a sparsely populated, heavily forested northern state, more education about the issues and the implementation of solutions would help reduce frustration.
- Stakeholders feel that utilities will need to communicate their reliability and resilience investments well and justify the cost-effectiveness of their choices. Stakeholders want utilities to look at a broad range of solutions to reliability and resilience concerns, from grid hardening to microgrids and demand response.
- Stakeholders recognize that having raised baseline efficiency successfully, EMT should look at other ways to add value beyond traditional efficiency improvements. Stakeholders also suggested targeting low-income residents for efficiency subsidies
- Electric load growth is seen as a near certainty as part of a transition away from carbon-polluting fuels towards electrified homes and transport. Load shaping capabilities will determine whether peak demand increases several times over or sees more modest growth. The ratepayer cost implications of this difference are significant and create urgency for a functional system to be put in place.
- Stakeholders hope that ratepayers can be partially insulated from grid upgrade costs and that the most cost-effective integration methods will be used.
- Stakeholders suggest revisiting policy for cost allocation for grid strengthening and resource interconnection upgrades to appropriately value projects with broad benefits while ensuring customers do not pay too much. DERs may require some system upgrades, but if sited well, they can also remove the need for other transmission and distribution upgrades, and that contribution should be valued.
- With long-term clean energy policy and subsidies, work towards sustainable energy and transportation systems can be driven by economics rather than centrally planned.
- Maine Utility/Regulatory Reform and Decarbonization Initiative (MURRDI) Recommendations identified that Maine utilities should investigate, adopt, and implement an all-encompassing, long-term, strategic grid planning process in coordination with existing proceedings and efforts such as the Maine PUC Grid Modernization effort, the

Maine Climate Action Plan, and the Governor's Energy Office Renewable Energy Goals Market Assessment. The group recommended the following factors to be considered when performing system planning.

- Things to be considered in the planning process:

    a. Where the electric energy will come from, including generation from supply-side resources, distribution-connected resources, and behind-the-meter resources.

    b. How the electric energy will be moved, including transmission and distribution infrastructure.

    c. How much electricity will be used, where the usage will occur, and for what purposes. This should include forecasting for electrification of transportation and heating.

    d. To what extent load flexibility—via changes enabled by intelligent rate design, autonomous customer-owned devices, active management of those devices, or other means—will contribute to satisfying grid reliability and balancing, affordability, and security needs, resulting in deferred or avoided infrastructure investments.

    e. What considerations and future utility capabilities will be necessary to plan and operate a safe, reliable, secure electric grid that enables and integrates high levels of DERs in front of and behind the meter, including electric vehicles, heat pumps, energy storage, and intermittent renewable generation.

    f. How planning, operational, and investment decisions will impact the following: the grid over the planning horizon, in terms of operations, reliability, and resilience; costs and cost allocation; and achievement of Maine's broad climate, economic, energy, environmental, and equity objectives.

    g. How interconnection should be handled, including transparency of and access to interconnection information, incentivizing project development in specific locations, identifying areas that will need additional hosting capacity, assessing how to value projects that have system benefits, evaluating resilience benefits, and identifying how to prioritize projects in the interconnection queue.

    h. The role of the utilities in grid planning, investment, and operations, including assessing whether the utility business model and related incentives/disincentives are aligned to implementing the electric grid that is needed to meet Maine's climate and energy requirements.

i. How to conduct grid planning with an eye towards phasing out fossil fuels in Maine, which will be necessary to meet climate goals.

j. How the investments necessary to build the grid of the future should be allocated among the utility rate base, project developers, and others.

k. The implications of actions taken or planned by other states and provinces in the region.

MURRDI also provides other recommendations and suggestions as follows.

- Load Flexibility Enabled by Dynamic Rate Designs: Maine should move toward a more dynamic grid with more granular load flexibility capabilities in a concerted manner. As a first step, Maine PUC should immediately look more closely at time of use rates and/or other dynamic rate structures that more accurately reflect the cost of producing and delivering power. It should also take into account how time-varying rate designs could help to meet the state's climate and energy requirements. The considerations that support this recommendation are as follows.

1) Time-varying Rate Design Considerations:

a) The pricing for time-varying rates should include energy, capacity, transmission, and distribution costs; otherwise, the price differential is unlikely to be large enough to make time-varying rate designs worthwhile.

b) The time periods for time-varying rate designs should take both cost and emissions into account (i.e., shifting load off-peak could be counterproductive if the electricity supplying the grid off-peak has higher emissions than the electricity supplying the grid on-peak). To support this, ISO-NE should explore more transparent reporting of marginal emission factors for carbon, nitrogen oxides, and sulfur oxides (this also applies to distribution locational marginal prices).

c) Time-varying rates can and should be designed carefully to bring about benefits to all customers and must be paired with protections for low-income customers. Importantly, time-varying rates have been shown to save low-income ratepayers money.

d) Time-varying rate designs need to be paired with complementary customer-side technologies to be most effective. The PUC should consider ways in which the utilities and Efficiency Maine can work more closely to deploy those technologies and ensure they're used effectively, including but not limited to expansion of grid flexibility pilots already managed by Efficiency Maine to test these technologies.

2) Timing and Process Considerations:

a) Maine's utilities, the PUC, and stakeholders should consider which customer segments will elicit the greatest benefits in response to the costs of developing time-varying rate designs in the near term, as well as whether there are existing rate designs (e.g., Central Maine Power's time-varying Rate A-LM for customers with thermal energy storage devices) that can be improved upon to begin making progress.

b) In cases where better data is needed to inform decision-making, the utilities, the PUC, and stakeholders should consider pilots that can generate that data.

c) It may be most effective to develop a general time-varying rate, with additional specific rate designs for particular customer segments as needed.

d) Developing time-varying rate designs can be a complex and time-consuming regulatory endeavor, yet doing so is necessary to enable the more granular load flexibility capabilities that will be needed in the future. Moreover, to make those capabilities available when they're needed, the process must begin in earnest now.

3) Specific Actions for Consideration:

a) Implement time-varying rates for electric vehicle (EV) home charging, which can immediately bring benefits to customers and the grid. In addition, consider the following:
i. Ways to use innovative technologies to reduce or eliminate the cost of sub-metering, such as through Wi-Fi-connected Level 2 chargers while maintaining acceptable data quality for customer billing.
ii. Ways to make the benefits of EV time-varying rates more accessible to low-income customers, such as subsidizing or reducing the cost of extending wiring and Wi-Fi service to the charger.

b) Encourage the PUC to require the standard offer service to reflect the hourly differentiated energy and capacity costs, which would align the energy side with the transmission and distribution side, reflecting the observation above that energy must be included to make time-varying rates fully worthwhile. In addition, consider the following:

i. If the PUC were to only suggest to the suppliers that they could offer this, they likely wouldn't, so it would need to be required, which is arguably within the PUC's authority.

ii. Alternatively, if this is suggested but not required, the PUC would need to create some assurances for suppliers that there will be uptake to make the product worthwhile.

iii. Data transparency, and the systems necessary to support data transparency, are vital to enable this. Those systems include AMI and provision of hourly interval data to standard offer bidders.

- Exploring a Distribution System Market Framework: The rationale behind this recommendation is that in order to operate a decarbonized electric grid in Maine, load

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will need to be flexibly aligned to renewable generation. The recommendation is for Maine's distribution utilities, the PUC, and other stakeholders to explore the opportunities, challenges, benefits, and drawbacks of establishing a market framework at the distribution level, including through pilot projects, as an initial step towards an electric system in Maine that allows DERs to provide all load flexibility capabilities that they can provide.

- Fostering Innovation: The Maine PUC, utilities, and stakeholders should explore opportunities to (1) enable using ratepayer dollars to pay for innovation investments in return for PUC oversight, and (2) create a forum for sharing innovative approaches being tested in the state and elsewhere, both by utilities and other entities, ultimately in service to meeting the state's emissions reduction targets.

- PUC Consideration of Climate, Equity, and Environmental Justice: Expand the PUC's decision-making framework to consider Maine's climate requirements, equity implications, and impacts on environmental justice communities. This will enable consideration of the full costs and benefits of energy investments in all decisions.

6.3 Best Practices

6.3.1 DOMINION ENERGY[71]

6.3.1.1 Practice Overview

As a result of the mandate from the Grid Transformation and Security Act of 2018 ("GTSA") that requires utilities to file a plan for grid transformation, Dominion Virginia Power developed its "Grid Transformation Plan." Dominion's distribution planning process aims to incorporate the impacts and opportunities provided by the expansion of Distributed Energy Resources (DERs) on the distribution system. The process involves running a multi-year Time Series Analysis (TSA), identifying times where technical violations may occur due to load growth or due to DER operation, designing appropriate mitigation, and evaluating the hosting capacity of the system for different capacities of DER.
DNV GL worked with Dominion to develop tools and processes for the implementation of Dominion's Integrated Distribution Planning (IDP) process.

6.3.1.2 Practice Main Goals

To implement the TSA approach, a process has been developed to develop estimated customer load and generation profiles. The TSA approach is a necessary change from traditional planning processes, which would typically focus on peak load analysis. TSA allows the planning engineer to address the interactions between load and generation on the system. This interaction increases the complexity of the system, making it difficult to immediately identify the worst-case condition. In addition, TSA offers several other opportunities, including addressing the impact of variable generation on voltage regulation equipment, assessing the extent of technical violations in terms

71 www.DominionEnergy.com/SmartEnergy , refer to Grid Transformation Plan SCC Filing, "Volume One."

of the number of hours out of the year they may persist, and designing non-wires alternatives such as energy storage systems.

6.3.1.3 Key Questions

At present, utility load measurements are mostly net-load measurements, which include the combined effects of load and generation. For the analyses carried out in the IDP process, load and generation must be separated so that different assumptions regarding generation capacity and output can be used without changing the load on the system (which is generally independent of generation output).

The ability to successfully perform time series modeling analysis ("TSA") of the distribution grid is heavily reliant on highly granular visibility of existing load and DER characteristics. Finally, given the uncertainty associated with the size and location of DER growth, probabilistic or stochastic analytical techniques will be required to evaluate the robustness of the distribution grid from the feeder head to the feeder edge.

6.3.1.4 Process Design

- **Process Flow**[72]

The Company plans to implement the following (see Figure 24) process-related enhancements to its distribution planning process to move toward IDP.

	Inputs	Modeling & Analysis	Alternatives Evaluation	Final Plan
Integrated Distribution Planning	• Feeder load forecast scenarios (time series) • DER & emerging tech growth forecast scenarios • Additional planning inputs: (hosting capacity, AMI & IGD load and voltage data, all DER output data, feeder characteristics (EAM data), performance metrics, etc. • Engineering model build and framework for scenario based analysis • Network assessment (Static and Time Series Analysis) • Reliability assessment • Planning criteria	• Reliance on engineering models based on a high level of data granularity • Automated generation of time series analysis and holistic solutions • Inclusion of Non-Wire Alternatives (Storage, Advanced Inverter Functionality, DSM, etc.) • Inclusion of locational value of resources	• Traditional Grid Solutions • DER & DSM Opportunities • Grid Transformation Projects • Optimization of alternatives over time	**10 Year Distribution Forecast and Investment Roadmap** **Transmission and Generation System Planning Impacts**

Figure 24. Dominion energy's distribution planning process

- **Needed Equipment**

IDP is highly dependent on having highly granular and spatial visibility of existing grid conditions. The Company has a plan to transform its distribution grid (the "Grid Transformation Plan" or "GT Plan") to adapt to the fundamental changes to the energy industry described above and to meet its customers' needs and expectations. Many of these proposed investments are foundational to IDP, including investments in advanced metering infrastructure ("AMI"); a self-healing grid, including intelligent grid device and an advanced distribution management system ("ADMS") with system capabilities for distributed energy resources management ("DERMS"); and Advanced Analytics. Advanced Analytics can suitably model the behavior of the entire distribution network, including the renewable resources.

[72] www.DominionEnergy.com/SmartEnergy , refer to Grid Transformation Plan SCC Filing, "Volume One."

6.3.1.5 Highlighted Results

Figure 25 provides the maturity curve presented in 2019, showing the evolution of integrated distribution planning over time as enabling technologies are deployed.

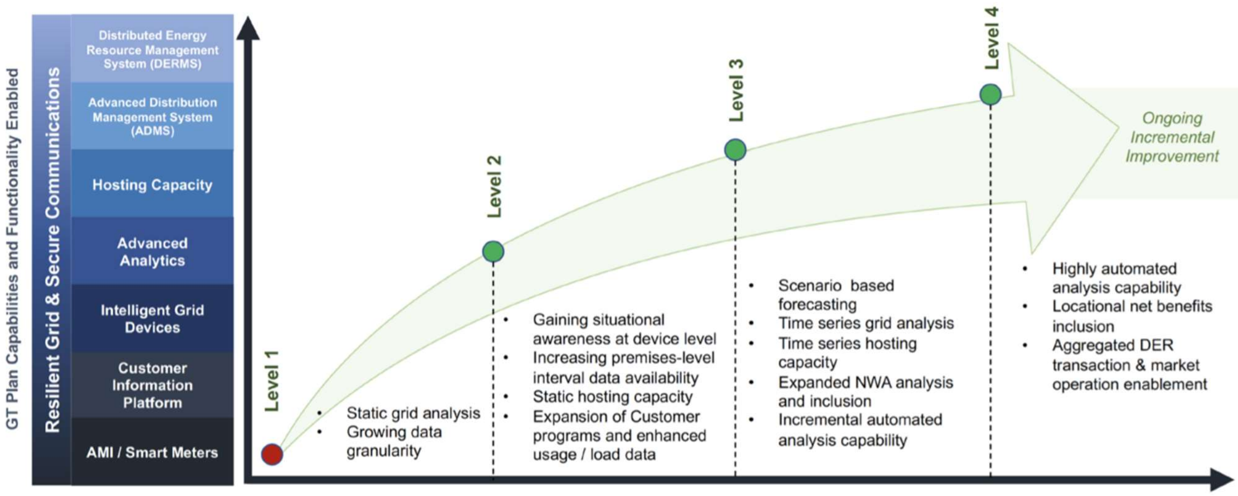

Figure 25. Integrated Distribution Planning Maturity Curve[73]

Since 2019, the Company has transitioned from Level 1 to Level 2. Notable successes in the evolution toward IDP include:

- Centralization of the Company's organizational structure such that the one team focuses on all distribution-related modeling and data analysis activities.
- Installation of ADMS.
- Development of an initial forecast of DERs by feeder.
- Publication of a hosting capacity tool that allows customers and developers to see the sections of the distribution system that may be more suitable to site new clean energy installations.
- Initial deployment activities for two battery energy storage systems ("BESS") pilot projects and the Locks Campus Microgrid, which will help the Company to study future non-wires alternatives; and
- Collection of additional premises-level data from AMI.

Drivers for Time Series Analysis

- **Interactions of Load and Generation:** It is important to model load and generation profiles independently since the load used by the customers can be masked during part of the day by the solar/wind generation.
- **Load Management:** Separation of load and generation profiles allows for more accurate implementation of load growth assumptions.
- **Generation Limits:** Developing time-based profiles for load and generation since it is generally assumed that generation on a distribution circuit will have the most significant

[73] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/projects-and-facilities/electric-projects/grid/gt-plan-phase-ii.pdf?la=en&rev=0cd40dd1b5674ebf813de4f10d5e440d

impact at times when the load is low. However, this may not be relevant if the generation is solar based (and thus only operational during daylight hours) and the minimum circuit load occurs at night. This allows the utility to determine reasonable and reliable limits on generation output without appearing overly conservative to their customers, which is important as demand for customer-sited generation increases.

- **Mitigation Analysis:** Traditional analysis of single, worst-case time-steps may limit options when a generator is found to cause a technical limit to be exceeded to install equipment upgrades, such as reconductoring or transformer replacements. However, providing a time-based representation of how and when the limitations occur can inform new mitigation strategies.

6.3.1.6 Software and Data Sources

Processes related to integrated distribution planning analysis in the software Synergi are shown in Figure 26. The tools developed here are tested on three sample circuits selected by Dominion, referred to in this report as F62710, F71475 and F81305.[74]

[74] www.DominionEnergy.com/SmartEnergy , refer to Grid Transformation Plan SCC Filing, “Volume One.”

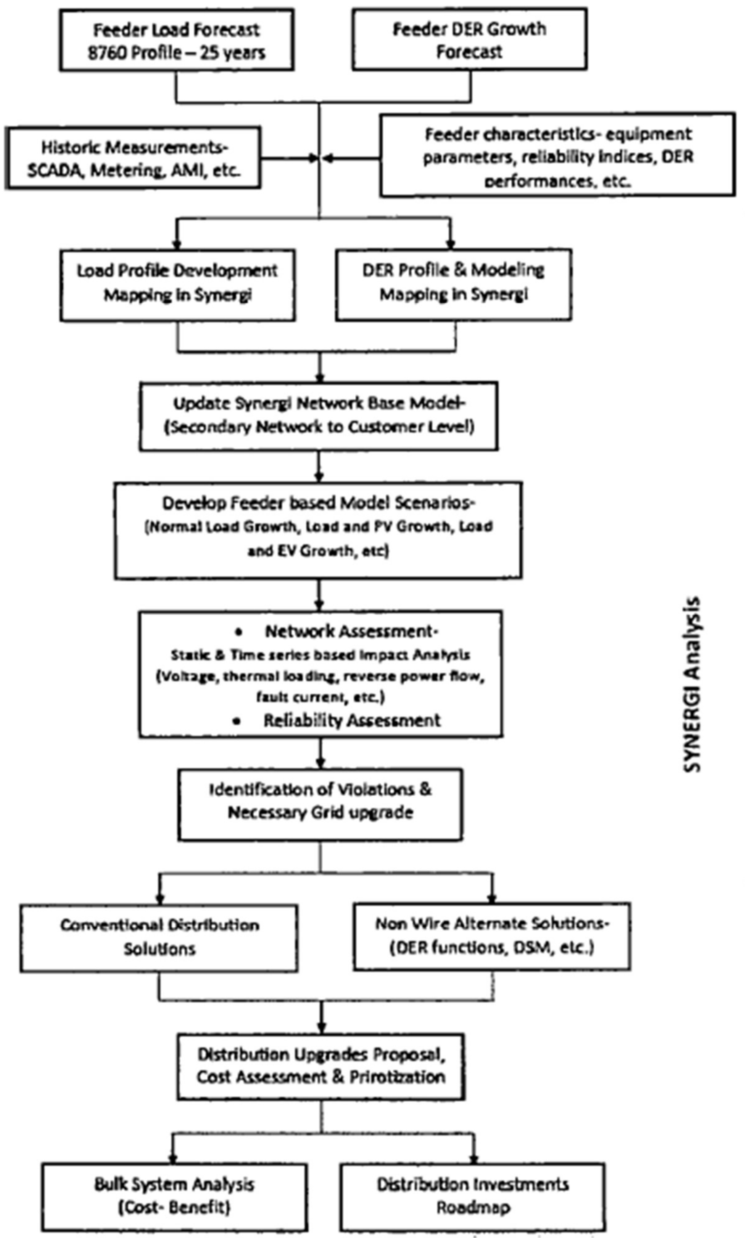

Figure 26. Processes related to integrated distribution planning analysis

6.3.1.7 Limitations

According to Dominion Energy's Distribution Grid modernization report, on the transformational change summary, the following items (see Table 10) can be mentioned related to the restrictions and challenges that the utility is facing in regard to integrated distribution planning.

Table 10. Challenges Dominion Energy is facing towards IDP

	Today's Energy Grid	Transformed Grid
Smart Meters	-> Current meters provide limited information to utility and customer- Dominion Energy does not know if your power is out	->100% fully deployed AMI. ->New and more frequent data, including outage awareness. Remote meter reading and service connections.
Self-Healing Grid	->Operating system designed for one-way power flow. ->Limited deployment of automation and monitoring	->Automated devices and controls that isolate outages and reroute power. ->Real-time situational awareness from thousands of new intelligent devices.
Physical & Cyber security	->Not "Digital Ready" ->Limited physical protection for key assets	->Two-way communication over a secure network.
Adaptive to Renewables	->Limited monitoring of DG impact to customers DG interconnection process & tools has limited scalability to support future growth.	->Streamlined DG interconnection process.
Predictive Analytics	->Analytical efforts are largely reactive and focused on single processes. Insufficient data sets	-> "Digital Grid" provides predictive capabilities to efficiently plan and operate power grid. ->Real-time data enable better decision making, modeling, and predictive analysis.

6.3.1.8 Observed Results

According to Dominion Energy[75]:
The TSA approach is a necessary change from traditional planning processes, which would typically focus on peak load analysis. TSA allows the planning engineer to address the interactions between load and generation on the system. This interaction increases the complexity of the system, making it difficult to immediately identify the worst-case condition.
In addition, TSA offers several other opportunities, including addressing the impact of variable generation on voltage regulation equipment, assessing the extent of technical violations in terms of the number of hours out of the year they may persist, and designing non-wires alternatives such as energy storage systems.

6.4 Gap Analysis

Stakeholder concerns are mostly centered around reliability and rate affordability and design in Maine. Stakeholders believe that the perception of low reliability and high electricity rate at the same time will lower the customers' trust and push the large customers to avoid relying on the grid or to locate out of state. Also, reliability challenges and quality of service may prevent the new industries and other large customers from deploying in the state. Another concern is that the high electricity rate may prevent or slow down electrification adoption in the upcoming years. Both

[75] www.DominionEnergy.com/SmartEnergy , refer to Grid Transformation Plan SCC Filing, "Volume One."

CMP and Versant identified reliability initiatives that should improve customer reliability outcomes.

Rates and rate design are a more complex issue that must consider both the benefits and cost burdens on a wide variety of customer groups as well as the utilities. Since the Investigation and Gap Analysis efforts within this and previous reports are primarily utility focused, specific rate structure and recovery elements have been omitted from the Gap Analysis in favor of referencing a more consensus-driven approach exemplified by the MURRDI report. Rate and incentive design have important consequences on affordability, technology adoption, and overall economic efficiency.

Non-Wires Alternatives (NWA) are another key focus area for integrated distribution planning. The existence and structure of the Non-Wires Alternative Coordinator in Maine provides a layer of oversight and legitimacy in the eyes of non-utility stakeholders, but the capabilities and engagement of the utilities in the NWA process are still critical to the overall success of NWA solution utilization, as the utilities are best positioned to understand the reliability and capacity need areas within their system, engage in system modeling and data utilization, and build business cases for solutions where they may be cost effective. The higher the level of data and model quality and utility engagement, the more efficiently the process can be conducted.

As an example, the distribution investment deferral framework (DIDF) in California, which was established and required by the California Public Utilities Commission (CPUC), utilizes utility-identified grid needs to allow third parties to propose solutions that address the grid need through methods other than traditional infrastructure upgrades. Because the constraint, technical requirements for the solution, and support information are readily available, DER developers or other interested parties can submit solutions leveraging a wide variety of available technologies. These proposals are then evaluated by PG&E for feasibility, cost, and other criteria to ensure the ability of the proposal to meet the necessary requirements. While the is clearly different from the NWA Coordinator framework in Maine, it serves as an important example of the value of utility engagement in the identification and implementation of third party-based Non-Wires Alternatives.

6.4.1 CMP

1) **Model Build Integration -** CMP identified planned improvements in the integrations between the CYME analysis platform and distribution data sources to improve model quality, study capabilities and reduce manual efforts for system planners. CYME is currently integrated with the GIS system through the CYME Gateway, which provides electrical connectivity and component information, and utilizes billing information as part of the load model build process. Information from other data sources must be manually entered by the planning engineers. This includes the protective device, voltage regulator, and capacitor bank settings, as well as the locations and sizes of interconnected DER. Because of the manual nature of this process, CMP currently only models DER over 100kW as part of planning and interconnection studies. In the future, CMP plans to integrate CYME with AMI and SAP to automate these processes, as well as enable more

granular time-series studies based on AMI meter data. This should reduce manual planning efforts and improve study timelines and results quality.

2) **Continued Reliability Improvement -** Service reliability is one key area in which CMP can continue to improve. CMP's 2020 SAIFI and SAIDI (excluding major event days), at 2.04 and 220.8 minutes respectively[76], indicate relatively strong performance relative to the challenges of heavy forestation and relatively low customer density. At the same time, a review of outage data identified that 46,120 (7.13%) of CMP's approximately 646,000 customers experienced 6 or more outages for each of the last 3 years. When it comes to duration, 82,402 (12.76%) of CMP's customers experienced more than 18 combined hours of outage for each of the past 3 years. A continued focus on reliability improvements are necessary in order to meet growing customer reliability standards and expectations, especially with the increasing focus on electrification.
3) **Capital Project Evaluation -** In June 2021, CMP began utilizing a new capital project planning process and criteria adopted by AVANGRID. This process is intended to categorize proposed projects and prioritize them based on a variety of business drivers and potential impact levels. This process includes several internal oversight and governance groups in a vetting process, which projects pass through before ultimately being budgeted and executed. In practice, this process relies heavily on the judgment of the proposer and stakeholders involved in the review process. Under this process, all reliability improvement projects which improve at least one reliability metric and are not mandated are scored as "Significant". CMP relies on SME input and relevant data to prioritize projects within this class rather than a defined analytical calculation of project value. As alternative evaluations become more complex, especially with the growing inclusion of Non-Wires Alternatives, a more analytically driven approach to project valuation is recommended so that all projects and alternatives are considered on a more equal foundation. SME input will always be valuable and necessary for project justification, but channeling that input into risk avoidance, cost incurrence, or other analytical comparisons should be strongly considered.

4) **AMI Data Utilization** – CMP is not currently utilizing AMI data as part of system planning efforts. Building the integration between AMI data and CYME will improve distribution model quality as well as enable more advanced time-series based studies, which will be necessary for advanced planning and distribution analyses. CMP identified that this integration is currently on their roadmap.

5) **Time Series Planning Capabilities –** Migrating from static worst-case model evaluations to time-series based approaches which can more accurately account for the effects of various DER profiles will become necessary as DER, EV, and advanced control capabilities become more commonplace on the distribution system.

6.4.2 Versant

[76] https://www.eia.gov/electricity/data/eia861/

1) **Continued Reliability Improvement –** For the past four years, Versant has overperformed on SAIFI relative to their 2020-2022 targets, with 2020 SAIFI and SAIDI (excluding major event days) at 2.40 and 319 minutes respectively[77], but still has room for improvement. A continued focus on these efforts will be critical to build consumer confidence, especially as the distribution system becomes more fundamental to transportation and heating.
2) **Forecasting Capabilities –** Versant does not currently project DER, EV, or electrification growth as part of their planning processes for short or long-term impacts. Because Versant has available distribution capacity in many areas, forecasting such impacts has not been a significant concern. As EV and electrification become more commonplace, especially when concentrated in specific areas, will become significantly more important to ensure that capacity remains available, and solutions are planned sufficiently far in advance as to enable cost effective solutions which may have longer lead times or be more complex to analyze and source like Non-Wires Alternatives.
3) **Capital Project Evaluation –** Versant's current investment justification processes utilize a mix of analytical methods (e.g., Cost per avoided interruption and cost per avoided hour of interruption) and SME input to identify reliability and capacity improvement projects. Moving forward, Versant should continue to utilize analytical methods and strongly consider opportunities to increase the rigor and applicability of those methods to apply to capacity-driven projects, Non-Wires Alternatives, and other system upgrades.
4) **Time Series Planning Capabilities –** Versant currently only utilizes static cases for planning related studies and does not utilize SCADA or meter data for time-series studies. Migrating from static worst-case model evaluations to time-series based approaches which can more accurately account for the effects of various DER profiles will become necessary as DER, EV, and advanced control capabilities become more commonplace on the distribution system.

5) **Equipment Ratings -** To further expand capacity without additional capital investment, Versant should consider modifying its equipment rating practices, which currently utilize only the "Summer Normal" rating, to include both "Emergency" ratings (which are higher ratings intended to be utilized under contingency scenarios to increase capacity for short duration events) and "Winter" ratings (which are typically higher to reflect the increased ability of equipment to dissipate heat at lower ambient temperatures) where appropriate for winter peaking circuits.

6) **Regulator Controls -** Versant currently has voltage regulator locations that utilize Load Drop Compensation (LDC) controls. This creates the potential for misoperation of LDC controls when downline DER utilizes volt/var controls to regulate voltage. For a high voltage condition in such a scenario, the inverter volt/var curve will absorb reactive power to reduce the local voltage, which can cause the regulator controller to tap to increase the voltage due to the X setting of the LDC and increase in reactive power demand at the regulator. For larger installations or higher penetrations of smaller DER, this interaction can create runaway conditions, driving both the inverter(s) and the regulator to their extreme positions and negatively impacting voltage for customers downline of the

[77] https://www.eia.gov/electricity/data/eia861/

regulator. It is recommended that existing regulators which utilize LDC R and X settings be monitored for increases in downstream DER installations or have their settings changed where practical to eliminate the potential for negative interactions.

Table 11 summarizes identified gaps for both utilities regarding IDP.

Table 11. Summary of gaps for both utilities regarding IDP

Versant	CMP
Continued Reliability Improvement	Model Build Integration
Forecasting Capabilities	Continued Reliability Improvement
Capital Project Evaluation	Capital Project Evaluation
Time Series Planning Capabilities	AMI Data Utilization
Equipment Ratings	Time Series Planning Capabilities
Regulator Controls	

7 Conclusion

In this report, a thorough analysis of Regulatory Requirements, Modern Grid Elements, and Stakeholder Needs was provided which were used as targets for the distribution systems in Maine. After that, a gap analysis was provided which highlighted the gaps between the current state of distribution systems in the state of Maine maintained by Versant and CMP and the desired distribution system. The results of this report will be used as a basis for the development of a roadmap for the future of the distribution systems in Maine.

8 Appendix

In this section, a summary of both Versant and CMP's capabilities are tabulated in Table 12.

Table 12. A summary of Versant and CMP's capabilities

Description	CMP	Versant
Geographic Information System (GIS)		
Software Utilized:	ESRI's ArcGIS as repository and source of truth for electrical connectivity, geospatial data, normal system operating status. Schneider ArcFM for modifying GIS data. SAP as repository and source of truth for equipment attributes, settings, maintenance plans, transmission and substation equipment, customer and customer transformer-mapping.	General Electric's (GE) Smallworld GIS as source of truth for all information contained (starts at load side of substation transformer). Includes transmission and Subtransmission lines. SCADA and the CASCADE software collect substation equipment and information. Perform annual GIS enhancement projects to improve various facets of their GIS.
Organizational Structure:	Managed by GIS Operations team. Editing restricted to GIS Operations personnel and Energy Control Center (ECC.)	Manage by Asset Management team. Planning manages bulk of system change updates upon project completions.
DERs in GIS:	Parallel operating DERs not mapped in GIS system but are available in the GIS viewing application.	Parallel operating DERs are mapped in GIS. Update process is the same as other equipment.

Description	CMP	Versant
GIS Integrations:	Integrated with CYME via CYME Gateway.	Integrated with CYME via extract through SQL scripting. GIS interface connected to OMS.
GIS Challenges and Future Plans:	Lack accurate data quality for phasing and customer to transformer connectivity. Grid Model Enhancement Project (GMEP) to perform field inventory of all distribution assets, phasing, and customer to transformer connectivity. GMEP estimated 2022 - Q1 2026. CYME integration does not include settings from SAP, however, plans in place to integrate these systems. Plans to integrate GIS with future Spectrum ADMS system.	Keeps accurate data via GIS/CYME validation projects. Ongoing GIS Enhancement capital project to ensure new devices are effectively modeled. Manual updates can lead to human error (improved through training and QA process implementation) Goal: Perform real-time GIS updates and minimize time lag between a project being in services, and GIS update.
Advanced Metering Infrastructure (AMI)		
Systems Utilized:	L&G AMI system for 40% of meters. Aclara AMI system for most other meters. Trilliant Head End System for managing AMI network. Trillient utilizes RF mesh for communications. Itron Enterprise used for MDMS.	L&G Turtle AMR system of about 35k meters (MPD). Aclara TWACS AMI system of about 130k meters (BHD). Both utilize power line carrier communications. L&G is one-way communications and is no longer supported by the manufacturer Aclara is two-way communications with hourly data reads and last gasp communications following outages.
AMI Data Access:	Smart Metering, Customer Billing, and IT have access. Customers have access to some energy data.	IT and the database team have write access. Engineering has read-only access to integrate MDMS data into CYME.
Functionality:	All meters can read kWh, kW and temperature. Over 40% of meters can be interrogated for voltage. About 4000 meters can read kVAR (deployment limited to necessary cases due to cost increase).	L&G meters collect kWh for billing. TWACS meters collect amps, kWh and kW. TWACS meters take hourly reads. All data is stored to MDMS.

Description	CMP	Versant
	Most customer data collected hourly. Some customer data collected in 15-minute intervals as necessary. AMI data stored for six years. All meters capable of remote reads and connect/disconnect. AMI meters can be pinged by head end system. Capable of theft detection. Support Zigbee protocol for HAN. AMI energy data available to customers through a portal.	TWACS meters have some theft, tamper, and reverse rotation detection. Meters capable of HAN connection.
AMI Integrations:	IEE is integrated with CIS through the SAP AMI Integration module. Utilize AMI data to log momentary outages and calculate MAIFI.	Complex integration between MDMS and CIS for billing. MDMS integrated with GIS. Billing Systems integrated with CIS. Can ping meters through OMS or MDMS head-end.
AMI Challenges and Future Plans:	Limited voltage reading capabilities. Rural areas can require additional buildout of RF mesh network. Not currently used for to feed into power flow results. Plans to integrate AMI data to CYME for load profile development. Working on solution with vendor to help with remote firmware updates for meters without that capability.	Cannot perform on-demand reads. PLC limitations mean VO programs are not scalable. Latency challenges with existing AMR. No OMS integration. 2022 plans to upgrade current systems to the Itron Riva AMI system with new communications, on-demand reads, data points, OMS integration, remote capabilities, new billing setup, theft detection, and FAN optimization. Examining options to make a customer's AMI data available to them.
Distribution System Modeling		
Software:	Use CYMEDIST for system modeling. Use CYME Gateway for map integration from GIS.	Utilize CYMEDIST for system modeling.

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Description	CMP	Versant
Methods:	Device settings are manually input. DERs manually added. Most studies model the system at a single point in time. Build process involves correction of a large number of errors. Billing data utilized to assign load to customer transformers.	Model building process imports data from GIS, SCADA, and Cascade. All studies model the system at a single point in time. Utilize kWh billing data for load allocation. Build process involves correction of relatively small number of errors. Models pro-actively built to be readily available. Highly accurate model according to Versant through proactive GIS update efforts. Normal configuration power flow models are based on substation peak from previous year.
DER Applications:	Utilize CYME Long-Term Dynamics Analysis module for solar PV intermittency. DG interconnection.	DER are incorporated from GIS when completed.
Modeling and Applications:	Balanced power flows on 67% of feeders (due to insufficient model quality). Unbalanced power flows on remaining 33% where model quality allows. Long Term Dynamics Time-Series Studies. New interconnections. New load additions. Motor start studies. Contingency analysis. Capable of Non-Wires Alternatives modeling.	Unbalanced power flows. New interconnections. New load additions. Contingency analysis. Motor Start Studies Capable of Non-Wires Alternatives technical modeling.
Challenges and Future Plans:	Data quality issues stem from lack of phasing and customer to transformer linkage data which should be addressed in GMEP. Plans for CYME Initiatives Project to reduce manual efforts and expand integrations, improve DER	Versant manually builds and load allocate their models. Not currently capable of performing time-series studies in CYME.

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Description	CMP	Versant
	application, provide groundwork for load profiles using AMI. Planning to utilize other time-series planning studies. 2022 plans for expanded Hosting Capacity studies.	CYME not currently utilized for hosting capacity analysis but have plans to implement a solution. Plans to create integrated PSSE model between T&D systems.
Distribution System Operations Management Systems (DMS/ADMS)		
Current Methods:	No DMS/ADMS system. Utilize SCADA connected equipment to monitor grid where possible. Use SMWeb to provide geographical view of networks[78].	No DMS/ADMS system.
Challenges and Future Plans:	Does not currently have a DMS/ADMS. Lack model accuracy needed to have ADMS system, which will be addressed in GMEP. Q1 2022 plans to begin deploying Siemen's Spectrum ADMS system. Expect Spectrum will lead to Automated Grid Restoration capabilities even before GMEP.	Versant shared that DMS systems were among future investments discussed in its most recent rate case but expressed need to consider balance of the systems value to cost to ensure cost stability for customers.
Outage Management System (OMS)		
System:	OMS system built using custom C# applications integrated with SAP. Front end is SMWeb outage map and AMI pings.	Utilize GE PowerOn OMS. Includes public facing outage map with restoration times.
OMS Data:	Outage data kept indefinitely in the Distribution Outage Database. Outage data manually recorded. Data accessible to relevant members of the ECC, Field Operations, and Operational Performance groups.	7 years for outage data retained in OMS. Asset information updated biweekly. Outages reviewed on a monthly basis. Records of Post-Event Reports kept in distribution operations.
OMS Integrations:	SMWeb integrated with SAP.	Integrated with GIS for connectivity. Integrated with CIS for customer information.

[78] No integration between SCADA and SMWeb.

Description	CMP	Versant
Challenges and Future Plans:	Single-phase outages on three-phase equipment can create issues within the outage handling process and result in incorrect predictions. GMEP will help with outage inaccuracies. No OMS integration with mobile systems for field crews. 2024 plans for mobile functionality for field crews. Spectrum ADMS platform will combine SCADA and OMS into one system.	Versant has recognized potential improvements available through process automation. Plans for a more proactive integration with AMI last gasp outage pings.
Supervisory Control and Data Acquisition (SCADA)		
Methods:	System can perform real-time operations for SCADA connected equipment.	SCADA and the Cascade software capture detailed substation equipment and one-line information. Real-time responses triggered from alarms for high impact system conditions. Operating guides are developed for use by dispatchers to respond to outages or other relevant system conditions.
SCADA Connected Equipment:	170 of 206 substations[79]. 471 of 533 substation protective devices. 441 line reclosers.	All 26 substations and their reclosers in the MPD district. 47 substations (90%) and their reclosers in the BHD district. 40 line devices. 20 substation LTCs.
Data Storage:	10 year retention. Store key magnitudes in a back-office repository.	7-10 year data retention. Data maintained within SCADA and separately within a Historian (Oracle).
Challenges and Future Plans:	Planned project to install line sensors in substations without SCADA. 2022 Spectrum deployment will integrate SCADA with OMS.	Currently does not have real-time study or data analytics tools within SCADA platform. Future migration to ADMS will enable more advanced system management.

[79] For substations that do not have SCADA integration, peak load data is retrieved bi-monthly.

Description	CMP	Versant
	Digitization Project to increase SCADA penetration on distribution feeders.	
Identified System Integrations.		
Existing Integrations:	Utilize Itron Metrix ND for load forecasting and market planning.	GIS and OMS. Manual between GIS and CYME via SQL scripting. MDMS and CIS. MDMS and GIS. OMS and AMI. OMS and MDMS.
Integration Plans:	Spectrum will integrate EMS, SCADA, OMS, and ADMS functionalities.	Planning to migrate to an enterprise service bus approach for data integrations.
Distribution Planning		
Planning Criteria for Capacity:	90% rating threshold to begin identifying capacity projects. Utilize 10-year forecast to address capacity issues.	85% rating threshold to begin identifying capacity projects. Utilize 10-year forecast to address capacity issues.
Planning Criteria for Voltage Limits:	ANSI Range A[80]: ±5% of nominal voltage or 114-126V on 120V base. Range B[81]: +5.8% to -8.3% of nominal voltage or 110-127V on 120V base.	ANSI Range A: 114-126V on 120V base.
Planning Criteria for Power Factor:	Violation occurs at <97% PF at substation during peak conditions.	Power Factor correction as needed
Planning Studies:	[82]Power Factor Analysis. Capacity Analyses. Motor Start Analysis. Voltage Analysis. Loss of Load Analysis. Load Balancing. Distribution Automation. Reliability. Resiliency. DER Analysis. Quality of Voltage Supply Analysis.	Power Factor Analysis Capacity Analyses. Motor Start Analysis. Voltage Analysis. Loss of Load Analysis. Load Balancing. Distribution Automation. Reliability. Resiliency. DER Analysis. Quality of Voltage Supply Analysis.

[80] Normal operating range.
[81] Temporary range for periods of abnormal operation.
[82] Voltage, capacity, power factory, etc., study criteria are based on AVANGRID's Distribution Planning Criteria.

Description	CMP	Versant
EV Adoption:	9 EV load growth scenarios through 2030. Increasing Level 2 charger support. Implementing DCFC[83] Delivery Charge Pilot.	No EV forecasting.
Challenges and Future Plans:	Plans for improved utilization of large data sets and multiple data sources for forecasting. Developing integrated system planning roadmap focusing on four main areas; Stakeholder Engagement, Advanced Forecasting, Advanced System Modeling, and Solutions Identification and Evaluation.	2021-2022 upgrading at-risk substation transformers. 2021-2022 cut over non-standard voltages to 12.47kV. 2021-2022 replace antiquated equipment on the system. 5-year road map for improved accuracy and functionality of Business Support Structure systems. 5-year roadmaps to increase and improve automation.
	Reliability	
Methods:	Feeders sorted on average weighted SAIFI for years 2018-2020. Worst performing feeders with storms are chosen for resiliency programs. Worst performing circuits without storms are reviewed for Distribution Automation projects. Momentary outages recorded by AMI meters. Monthly program to evaluate previous month's outages to calculate MAIFI.	Prioritize reliability projects based on cost per avoided customer interruption or cost per avoided customer hour of interruption. Metrics compiled using 5-year historical data. Annual study of worst SAIFI circuits.
Reliability Performance:	2018-2020: **82,402**[84] customers of approximately 646,000 experienced 18 or more hours of outages per year. 2018-2020: **46,120** [85]of approximately 646,000 customers experienced 6 or more outages per year.	2018-2020: 10,616 unique devices operated at least once. 84% of those devices operated 1 time. 352 operated each year. None operated more than 6 times in each year. None exceeded 18 hours in each year.

[83] Direct Current Fast Charging.
[84] Marked as confidential.
[85] Marked as confidential.

Description	CMP	Versant
Challenges:		Does not have the means to track momentary outages with current AMI system.
DER Interconnection		
Level 1 & 2 interconnections:	Approximately 5000 existing systems.	1100 systems totaling 14 MW (as of Sept 2021).
Level 4 Installations:	17 existing. 487 requests.	147 queued projects.
Customer DER Applications:	Utilize web portal for DER applications.	No web portal for applications. Process for applications based on Commission Rules Chapter 324.
DER System Impact Studies Include:	Effective grounding analysis. Contingency analysis. Fault current analysis. Thermal analysis. Risk of Islanding (Sandia Screens). Protection evaluation. Voltage impact. Time-domain studies (Voltage Fluctuations). Voltage Regulator Tapping	Design review. Effective grounding analysis. Fault current analysis. Coefficient of grounding testing. Thermal analysis. Reactive Analysis. Output Drop Analysis. Protection evaluation. Voltage impact. Voltage Regulator Tapping Time-domain studies (PSCAD). • Risk of Islanding • Load Rejection Overvoltage • Ground Fault Overvoltage
Hosting Capacity	Pilot Hosting Capacity Analysis (not publicly available) planned to expand to system-wide study with expanded constraint evaluation in 2022.	Stated to be pursuing a solution to enable Hosting Capacity map development.
Challenges and Future Plans:	Web portal has no integration to planning tools or GIS software. Q4 2021: Next version of the portal will integrate with Global SAP system and allow electronic payment. Challenges related to interconnection volume relative to minimum load and transmission impacts of DER penetration.	Challenges related to interconnection volume relative to peak load, UFLS compliance, transmission impacts, and voltage control capabilities due to high DER penetration.
Distribution Equipment, Operations, and Maintenance		

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Description	CMP	Versant
Facilities List	Distribution Substations: 206 Substation Regulators: 432 Substation Transformer LTCs: 153 Substation Reclosers: 393 Substation Circuit Breakers: 98 Substation Transformer Breakers: 31 Substation Bus Tie Breakers: 11 Line Regulators: 844 Line Capacitors: 614 Line Reclosers: 1612	Distribution Substations: 76 Substation Regulators: 240 Substation Transformer LTCs: 32 Substation Reclosers: 171 Substation Breakers: 266 Line Regulators: 181 Line Capacitors: 274 Line Reclosers: 478
Notable Elements	No visibility of service transformer loading (expected after GMEP). Electronic line reclosers set for 3-phase lock-out. No existing control of line reclosers and capacitors, but part of future plans.	Utilizes R and X regulator settings. Minimal Line capacitor and regulator communications and controls. Asset Replacement Plan to replace aging infrastructure.
Distribution Control Center		
Control Structure	Split between Area Operators (substation and sub-transmission control) and local divisions (distribution line control). Planned to centralize after Spectrum deployment in 2022.	Centralized control structure (one for MPD and one for BHD)
Future Staffing Plans	Expand and centralize, including operators, trainers, work planning and scheduling, and study engineer(s).	Expand existing operators and supervisors to handle additional workload.
DER Impacts on Switching	SCADA required at sites 1 MW and above. Planned switching includes Engineering involvement to ensure alternate feed is capable of supporting load and DER.	Reclosers at 250kW / 500kW and above sites.