Central Maine Power
An Avangrid company

Integrated Grid Plan

December 2025

Index

A Message From our Leadership

As Maine experiences continued economic growth, rising demands for clean energy, and increasingly severe storms, we must continue to invest in our energy grid to ensure resilience, reliability, and modernization for the 21st century. Fundamental investments in poles, wires, and other core infrastructure will be critical to the success of our integrated grid plan. By making smart investments that strengthen Maine’s energy system, we can ensure a safe, reliable, and modern power grid for generations to come.

This inaugural Integrated Grid Plan (“IGP”) represents a step toward defining the scope and scale of what it will take over the next decade to facilitate and support Maine's economic and climate objectives.

The IGP aims to establish an honest and transparent dialogue about the current state of the grid and the necessary steps to align with Maine’s climate and energy future. It is a foundational step toward ensuring that the grid evolves to meet the needs of all Mainers—today and in the decades to come.

The findings presented in this initial IGP will inform future system design, taking into account factors such as implementation timescales, technology readiness levels, and evolving policy landscapes. However, these findings are not intended to replace existing capital or operational investment decision processes, nor do they override current governance frameworks within CMP. Instead, they complement ongoing planning and investment processes by providing a strategic lens through which long-term grid evolution can be assessed.

At Central Maine Power, we are committed to enabling a reliable, affordable and clean energy transition for the more than 670,000 electricity customers we serve in Maine. Each day we are in our communities making critical infrastructure upgrades like installing stronger poles and wires, deploying smarter technology and utilizing more resilient materials built to withstand tough weather. With 1,000 Maine-based employees, we’re proud to serve our customers with safe, reliable, and resilient service while also meeting the growing energy needs of our communities.

Linda Ball, President and CEO, Central Maine Power

Executive Summary

Maine is in the midst of a major transformation of the energy system, driven by the need for increased capacity, modernization, and resilience as electrification accelerates and severe weather events become more frequent. Central Maine Power ("CMP" or "the Company") is committed to investing decisively in a smarter, stronger grid that can meet growing demand from electric vehicles, heat pumps, and distributed energy resources ("DERs"), while withstanding the impacts of storms and supporting Maine's clean energy transition. CMP seeks to deliver reliable, low-emission energy, minimize environmental impacts, and promote actions that address climate change and customer affordability.

The impacts of climate change are not only a growing threat but are already being felt today. Maine has experienced stronger, more frequent storms over the past decade, including three devastating winter storms in December 2023 and January 2024 that knocked out power to hundreds of thousands of customers and caused more than $90 million in damage to public infrastructure[1]. As the most heavily forested state in the US, with 89% of its land covered by forest, Maine is particularly vulnerable to tree-related power outages and reliability challenges caused by the impacts of stronger, more frequent storms.

Responding to the threat of climate change requires both adaptation, including hardening the electric grid to withstand more frequent storms and building more resilient infrastructure, as well as a transformation of the energy economy, shifting away from fossil fuels to more sustainable and lower carbon sources of energy. As articulated in Maine's climate action plan, Maine Won't Wait, meeting Maine's nation-leading climate goals requires widespread electrification of transportation and heating, and a continued evolution towards clean and renewable electric supply.

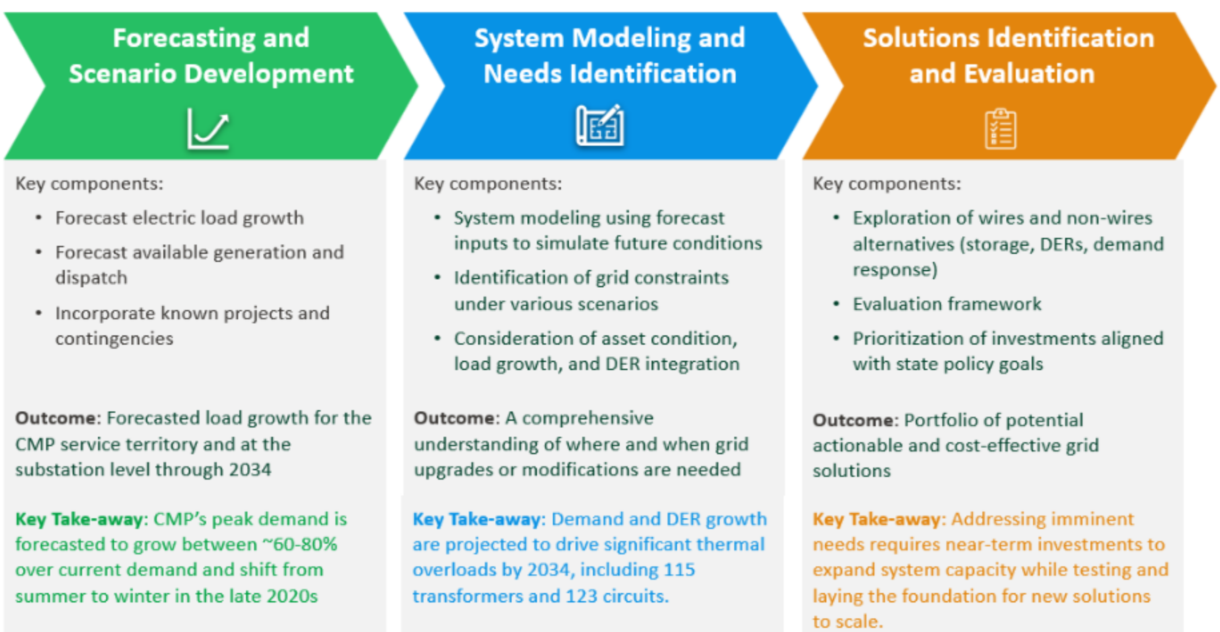
The electric power grid is foundational to this transformation. It will require new and expanded infrastructure to accommodate growing demand from electric vehicles and heat pumps and to integrate renewables and DERs. Continuing to modernize the transmission and distribution system is also critical to enhancing reliability and enabling flexibility. Realizing this energy future requires investment at pace and scale to make the grid smarter, stronger, cleaner, and more resilient.

This inaugural Integrated Grid Plan ("IGP") has been developed to fulfill the obligations set forth under the Maine Public Utilities Commission ("MPUC") Order filed on July 12, 2024 in Docket No. 2022-00322 (the "IGP Order"), which established requirements for developing a 10-year integrated grid plan that will assist in the cost-effective transition to a clean, affordable and reliable electric grid. The proceeding in Docket No. 2022-00322 complies with the legislation now codified at 35-A M.R.S. § 3147(2), An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future, which requires utilities to submit 10-year grid plans addressing priorities identified in the proceeding. The IGP Order set out three priorities (the "IGP Priorities") for the initial grid plans: 1) improve reliability and resiliency, 2) improve data quality and integrity, and 3) enable flexible management of consumers' resources and energy consumption. In alignment with the IGP Order, this inaugural IGP describes the methodology and results of the integrated grid planning process and provides a roadmap for electric distribution and transmission system investments and strategies to address the needs identified and achieve the IGP Priorities. This IGP, to the extent practical, follows the outline provided by the MPUC in Attachment C to the IGP Order, which is included for reference as Appendix B. We appreciate the Commission's recognition that this plan is a "significant task" and that "utilities require flexibility in developing their initial plans" (IGP Order at 12).

CMP recognizes and supports the benefits of integrated grid planning, which include:

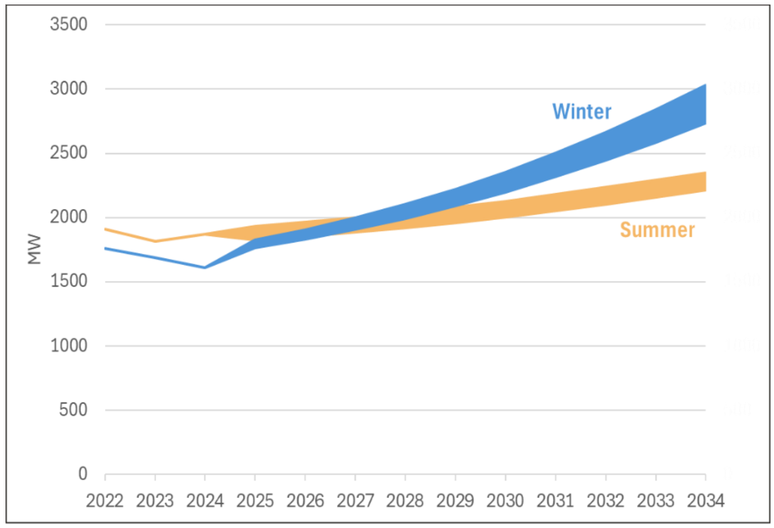
- enabling a more accessible, open and transparent planning process;
- engaging in holistic long-term strategic planning, including prioritizing and targeting investments;
- providing an overview of CMP's near and long-term transmission and distribution system plans and costs, and value to ratepayers from those investments; and
- providing a roadmap for investments in the grid Maine will need for the future while keeping rates manageable consistent with MPUC principles for investment and cost recovery.

The integrated grid planning process consisted of three primary phases: 1) forecasting and scenario development, 2) system modeling and needs identification, and 3) solutions identification and evaluation. The forecast sets the stage for how demand is expected to change over the next 10 years, including six seasonal snapshots for two scenarios. Using the 12 forecast scenarios as inputs to the planning models, CMP conducted system modeling to simulate future conditions and identify grid needs under various scenarios. Finally, CMP identified and evaluated portfolios of solutions to meet the needs identified.



The grid is at an inflection point where following relatively flat load over the past decade, demand is projected to increase over the next 10 years driven primarily by heat pump and electric vehicle adoption. The IGP load forecast, derived from ISO-NE's CELT forecast, projects peak electric demand to grow by approximately 1 GW over the next decade, or ~50% growth over current demand. The overall system peak is also expected to shift from the summer to the winter in the late 2020s. A winter peaking system has different operational characteristics and needs than a summer peaking system, which is a significant consideration in overall system and resource planning and investments.

CMP's peak load is forecasted to shift to the winter in the late 2020s



This growth is projected to exceed the capacity of the current network and create grid constraints. The IGP system modeling identified significant loading concerns emerging at 115 substation transformers and 123 circuits where the load is forecast to exceed normal equipment ratings by 2034. These forecasted grid needs represent 46% of all substation transformers and 26% of all circuits. Overloads and voltage violations in summer and winter peak load conditions are driven by the forecasted electrification of heating and transportation and tend to occur in densely populated southern and coastal regions of Maine. During the lightest load hours in many rural areas, strong solar output and low local demand are already creating reverse power flow constraints and voltage issues, which will be exacerbated with continued DER growth unless mitigations are in place.

Addressing imminent and forecasted system needs requires no-regrets near-term infrastructure investments to expand system capacity while simultaneously testing alternative solutions and laying the foundation for new solutions to scale. In the near-term, the focus is on addressing pressing constraints with the deployment of proven mitigation measures, including new and upgraded substations and circuits as well as load shift and circuit ties. Foundational technologies such as Advanced Distribution Management ("ADMS") and a Distributed Energy Resource Management System ("DERMS") can enable flexible management of load and generation assets to proactively mitigate grid constraints over the longer term, while the non-wires alternatives ("NWA") process is an avenue for evaluating NWA solutions to address near-term grid needs. The portfolio of solutions to address the distribution capacity needs identified in the IGP are estimated at $790 million - $1.3 billion.

In alignment with the IGP Order, CMP developed a roadmap for implementing solutions to address the needs identified through the IGP process, as well as a suite of investments and strategies needed to make progress on the three priorities identified by the IGP Order:

1. Reliability and resilience improvements
2. Improve data quality and integrity to maximize its use in distribution system planning
3. Promote flexible management of consumers' resources and energy consumption

The roadmap below outlines near-term and long-term investments and strategies to meet each of the IGP priorities. To improve reliability and resiliency, CMP will continue to focus on hardening the grid and make 'no regrets', proactive investments to address the capacity constraints identified in this IGP. In the near-term, CMP aims to improve data quality and transition to time series analysis, which will enable enhanced system modeling and more robust solutions evaluation in the longer term. Foundational investments in network communications platforms such as ADMS and DERMS, along with pilots and coordination with customer programs, will lay the groundwork for flexible management of consumers' resources.

CMP's 10-Year Roadmap to Advance IGP Priorities

IGP Priorities	Near-term (2026-2030)	Long-term (2031-2035)
Reliability and Resilience	• **Alleviate 166 network capacity constraints** and prepare for an **additional ~500 MW of electricity demand** • **Harden substations and circuits** to address asset condition • **Increase backup circuit-ties** to reduce the impact of outages • Continue deploying **Distribution Automation (SCADA devices) to improve visibility and remote-control capabilities** • **Pilot battery storage** for reliability and contingency backup use cases	• **Alleviate 72 network capacity constraints** and prepare for an **additional ~600 MW of electricity demand** • Create sufficient network hosting capacity to enable the connection of up to **1.6 GW of low-carbon generation** by 2035 • **Continue to harden substations and circuits** to address asset condition • **Continue to increase backup circuit-ties** to reduce outage impacts • Explore opportunities for **battery storage deployments in cost effective use cases**
Improve Data Quality, Integrity	• **Integrate AMI and SCADA data** into forecasting and system planning • Implement advanced forecasting and system planning tools to **enable time series analysis** • **Improve mapping of the distribution system** (Grid Model Enhancement Project) • **Enhance hosting capacity** maps and streamline the process to enable more frequent map updates	• **Enhanced system modeling** capabilities using **time series analysis** enables more automated and efficient evaluation of solutions • **Enable real-time data**, improved interoperability and enhanced capabilities in analytics, DER management and control
Promote flexible management of consumers' resources	• Deploy ADMS and DERMS features to **lay the foundation for integration and utilization of DERs**, enabling load flexibility • **Pilot smart grid technologies** such as peak shaving battery storage, Grid Enhancing Technologies (GETs), and DER Optimization • Coordinate with EMT on impacts of **customer flexibility programs**	• **Flexible load management and DER optimization** play a role in proactively mitigating peak demand, enabled by DERMS • **Enhanced DERMS** features enable new solutions and use cases • Scale deployment of smart grid technologies, such as GETs

Affordability and equity continue to be guiding principles as Maine makes the energy transition. The IGP roadmap is structured to make progress towards Maine's 2030, 2040, and 2045 climate goals, delivering incremental improvements over time and balancing the trade-offs between the pace of proactive investment and customer affordability. This long-term grid plan prioritizes cost-effective solutions to near-term grid needs, while also laying the foundation for future technologies and strategies to improve grid utilization and lower costs while continuing investments to improve reliability and resiliency, ultimately lowering future storm costs.

The system data, demand forecasting, system modeling and needs identification, and solution identification and evaluation summarized in this document reveal several key trends about CMP's system and CMP offers the following takeaways for addressing these impacts and building a smarter, stronger and more reliable grid.

Key Trends:	Key Takeaways:
1. **Increasing demand**: We're at an inflection point where demand is projected to increase over the next 10 years, driven primarily by heat pump and electric vehicle adoption, following relatively flat load growth over the past decade.	1. The current network does not have the capacity to meet the forecasted demand growth. The needs assessment identified **significant grid constraints**, including thermal overloads at 46% of distribution substation transformers and 26% of circuits.
2. **Shift to a winter peaking system**: Historically a summer peaking system, forecasts show the CMP system is expected to become winter peaking by 2027. A winter peaking system has different operational characteristics and needs than a summer peaking system, which is a significant consideration in overall system and resource planning and investments.	2. Addressing imminent and forecasted system needs requires **no-regrets near-term infrastructure investments to expand system capacity** while simultaneously **testing alternative solutions and laying the foundation for new solutions to scale**.
3. **Increasingly severe storms:** The impact of increasing extreme weather events over the past five years is creating reliability challenges for Maine's heavily forested and coastal landscape.	3. As CMP addresses capacity needs, new hardening standards for improved reliability and resiliency recommended by the Climate Change Protection Plan will be incorporated, along with proactive investments in grid hardening, distribution automation, and circuit ties are needed **to improve reliability and resiliency,** in the face of more frequent and severe storms.
4. **High level of DER penetration**: In just the last five years, DERs have grown from less than 100 MW to 989 MW, a very high penetration (56%) relative to CMP's system peak demand. Without real-time visibility and operational capabilities, this rapid growth has begun to create operational challenges on the grid.	4. Foundational investments in improved data accuracy, data integration and communications platforms, such as ADMS and DERMS, are needed to gain near real-time visibility to DERs and **enable flexible management and optimization of DERs.**
5. Across the country, customers are **increasingly facing affordability challenges**, driven by increasing demand and increasingly frequent and severe storms.	5. **Proactive planning and long-term cost recovery** enable the ability to manage costs more strategically and provide greater price stability and predictability.

01.
Vision for the Evolving Grid

1. Vision for the Evolving Grid

Maine is leading the nation with a comprehensive and ambitious strategy for climate action and energy transition. As the first state in the country to establish greenhouse gas reduction targets, Maine aims for 80% renewable energy by 2030, 100% clean energy by 2040, and carbon neutrality by 2045. The state's climate action plan, *Maine Won't Wait*[1], articulates key strategies for achieving Maine's clean energy and climate goals, including widespread electrification of transportation and heating and a continued evolution towards a clean and renewable electric supply. The electric power grid is foundational to this transformation. It will require new and expanded infrastructure to integrate renewables and DERs, accommodate growing electric demand, and reliably balance supply and demand.

Maine Pathways to 2040[2], which evaluates alternative pathways by which Maine might meet its climate and energy goals, finds that the clean energy transition "will require more efficient use of the existing system and significant expansion of the regional electric power system, including transmission and distribution infrastructure. This expansion is driven by increased peak electricity demand and the location and type of new (largely renewable) generation resources. Delays in developing this grid infrastructure could limit access to low-cost generation, delay clean energy development, slow the adoption of electrified heating and transportation, and cause reliability issues."[4]

The forecasted load growth from electrification and the increasing network access requirements from DERs highlight an urgent need for strategic infrastructure investment. This includes expanding infrastructure capacity and implementing foundational network management technologies to optimize grid utilization and manage a more complex grid with bidirectional power flows. Continued investments to improve reliability and resiliency are critical, as customers increasingly depend on the grid for their energy needs.

1.1. CMP's Role in the Evolving Grid

This IGP focuses on how CMP, in its role as a transmission and distribution ("T&D") utility, can ensure that transmission and distribution investments are optimized to meet reliability, resilience, and policy objectives. The concentration on strategic investment stems from CMP's role as a regulated T&D utility within the State of Maine. As a regulated utility, CMP's responsibilities are limited to the safe, reliable, and efficient delivery of electricity over its transmission and distribution infrastructure. CMP does not own generation resources, procure energy supply, or influence wholesale market pricing. Similarly, CMP has no authority over public policy programs or associated costs, such as renewable energy initiatives or state-mandated surcharges; these are established by statute and implemented under state policy frameworks. All aspects of CMP's operations, including service quality and rate structures, are

[1] Maine Climate Council, "Maine Won't Wait: A Four-Year Plan for Climate Action," December 2020.
[2] The Brattle Group and Evolved Energy Research. Prepared for the Maine Governor's Energy Office. "Maine Pathways to 2040: Analysis and Insights". January 2025.

subject to comprehensive oversight by the MPUC and FERC, ensuring compliance with regulatory requirements and alignment with the public interest.

The IGP modeling and results focus exclusively on the wires side of the system: evaluating infrastructure needs, distributed energy resource integration, and non-wires alternatives. Unlike an integrated *resource* planning framework, which combines generation and supply planning with T&D considerations, Maine's IGP does not address resource adequacy or energy supply decisions, which comprise a substantial portion of the costs borne by customers associated with energy usage. Those functions remain the responsibility of competitive suppliers and regional market operators. This distinction underscores CMP's limited role: while CMP provides critical input on grid needs and solutions, it does not plan for generation resources or influence supply-side strategies.

Nevertheless, this Integrated Grid Plan provides CMP's roadmap for planning and preparing for the changes expected over the next 10 years, including infrastructure investments designed to meet the challenges of stronger, more frequent storms, increasing peak demands driven by electrification, the evolution of a bidirectional grid, and aging grid infrastructure.

CMP's investments and strategies are designed to support Maine's clean energy and climate goals and achieve the three IGP Priorities set out in the IGP Order.

IGP Priorities established by MPUC for the initial grid plans	
Priority #1: Reliability and resilience improvements	Make investments that cost-effectively maintain or improve reliability
	Reduce barriers to promote cost-effective non-wires alternatives (NWA) solutions and identify any process improvements /efficiencies
	Build climate adaptation into the investment solution mix
Priority #2: Improve data quality and integrity to maximize its use in distribution system planning	Leverage investments in Advanced Metering Infrastructure (AMI)
	Improve mapping of the distribution system and develop a governance policy or protocols for maintaining the integrity of the data on an ongoing basis
	Develop initial roadmap for advancing time-series planning models
	Enhance hosting capacity maps to benefit stakeholder decision making by standardizing them across utilities
Priority #3: Promote flexible management of consumers' resources and energy consumption	Improve forecasting electric vehicle (EV) load, distributed energy resources (DER) adoption, and climate parameters
	Support integration and utilization of DERs to enable load flexibility and resilience
	Technologies or programs to shift load from system peak to reduce Maine's share of the Regional Network Service (RNS) charge

The IGP Priorities were established by the MPUC in the IGP Order[3], based on input from stakeholders at workshop meetings and through written comments. In addition to these three IGP Priorities, the IGP takes into account the cost-effective achievement of the State's climate action and Green House Gas (GHG) emission policies where applicable. The following sections describe CMP's planned investments, activities, and strategies for meeting the priorities established for the inaugural Integrated Grid Plan.

1.1.1. Priority 1: Improve Reliability and Resilience

Ensuring a reliable and resilient electric grid is paramount, particularly as weather variability, aging infrastructure, and increasing energy demands continue to challenge the system. This is even more critical as customers increase their reliance on the electric system to meet their heating and transportation needs. While storms remain a key risk factor, other operational pressures such as equipment wear, growing customer needs, and system capacity constraints highlight the necessity for continued investment in grid hardening.

The IGP demand forecasting and system modeling process identified significant near-term needs, including 85 overloaded transformers and 81 overloaded circuits in the next five years, which are described in more detail in Section 4. Maintaining reliability and resiliency requires proactively identifying and implementing solutions to address these system constraints and avoid equipment failures.

CMP aims to proactively strengthen the electrical system, reduce service disruptions, enhance safety, and improve long-term operational efficiency. Grid investments and operational strategies needed to improve reliability and resiliency and achieve IGP priorities are:

IGP Priority 1: Improve reliability and resilience	CMP's Key Strategies, Investments and Operations	More detail
Make investments that cost-effectively maintain or improve reliability	**Make foundational investments that cost-effectively maintain or improve reliability** by proactively addressing aging infrastructure, storm hardening substations and distribution equipment, expanding transmission and distribution automation, creating back-up circuit connections, and expanding local, internal workforce, thereby reducing reliance on external contractors.	Section 2.1
Reduce barriers to promote cost-effective NWA solutions and identify any process improvements /efficiencies	**Reduce barriers to promote cost-effective NWA solutions** through leveraging more granular data and advanced planning, standardizing benefit-cost analysis, and piloting new technologies. The transition to time series analysis will provide insights into the duration and timing of anticipated grid needs, which will allow a better understanding of where alternative solutions could play a role. The long-term needs identified in the IGP enable a more proactive approach to targeting projected grid needs with alternative solutions.	Section 5

[3] IGP Order. MPUC Docket 2022-00322. Jul 12, 2024.

IGP Priority 1: Improve reliability and resilience	CMP's Key Strategies, Investments and Operations	More detail
Build climate adaptation into the investment solution mix	**Build climate adaption into the investment solution mix** by incorporating site-specific resilience measures identified through the Climate Change Resiliency Plan (CCRP) into the grid planning process at the project identification or prioritization phases, such as stronger wood poles, fiberglass crossarms, spacer cable, tree wire, steel poles, circuit topology updates, or targeted undergrounding.	Section 4.4

For customers, these investments mean fewer outages, quicker restoration times, and a more dependable power supply. Strengthening infrastructure also reduces emergency maintenance costs and improves overall system performance, helping to keep rates stable and service quality high. By modernizing key components and implementing targeted grid hardening strategies, CMP is ensuring that its electric system remains robust and capable of supporting evolving customer needs.

1.1.2. Priority 2: Improve Data Quality and Integrity

A smart, reliable, and decarbonized electric grid demands advanced system modeling and operational capabilities to unlock the full potential of modern technologies and enable greater customer flexibility. Achieving this vision requires a systematic, data-driven approach grounded in comprehensive monitoring and data collection across the entire electricity network.

As the energy landscape evolves—with increasing electrification, distributed energy resources (DERs), and dynamic load profiles—traditional planning methods based on static snapshots are no longer sufficient on their own. While still in the relatively early stages of adoption, a shift to time series analysis will enable CMP to account for the granular effects of DER and load profiles on an increasingly complex grid and evaluate opportunities to improve grid utilization.

To meet Maine's climate goals and ensure cost-effective grid investments, CMP is committed to improving data quality and integrity and maximizing its use in distribution system planning. In alignment with the IGP priorities established by the MPUC and the recommendations in the EPE CMP Roadmap Report[4], CMP developed a roadmap to enhance data utilization, integrate time-series analysis, and modernize planning practices:

[4] Maine Utilities Distribution Investigation and Roadmap | Electric Power Engineers (EPE) - Energy Engineering Consultants

IGP Priority 2: Improve data quality and integrity to maximize its use in distribution system planning	CMP's Key Strategies, Investments and Operations	More detail
Leverage investments in Advanced Metering Infrastructure (AMI)	**Leverage more granular grid data** through integrating Advanced Metering Infrastructure (AMI) and supervisory control and data acquisition (SCADA) data with forecasting and planning tools.	Section 6.1
Improve mapping of the distribution system and develop a governance policy for maintaining the integrity of the data on an ongoing basis	**Improve distribution system mapping** through the Grid Model Enhancement Project (GMEP), which includes a comprehensive field survey of CMP's distribution system, reconciling historical records with field collected data, and establishing a data governance process to maintain data quality.	Section 6.1
Develop initial roadmap for advancing time-series planning models	**Transition to time-series forecasting and planning**, leveraging more granular data and advanced forecasting and planning tools to shift from traditional static-point forecasting (e.g. summer and winter peak) to dynamic, time-series forecasting and modeling that supports hourly analysis across the full year (8760 hours).	Section 6.1
Enhance hosting capacity maps to benefit stakeholder decision making by standardizing them across utilities	**Standardize hosting capacity maps across utilities** to improve stakeholder decision-making. CMP is exploring approaches to automate hosting capacity map updates, through a centralized server initiative (CYME Server), as it is currently a manual and time-consuming process. CMP is also exploring process improvements to expedite DER interconnection applications automation.	Section 6.3

See Section 6 for more detail on CMP's roadmap to enhance data utilization, integrate time-series analysis, and modernize planning practices.

1.1.3. Priority 3: Promote Flexible Management of Consumers' Resources and Energy Consumption

Utilities plan and build the grid to meet power demand at the peak hour of the year to ensure reliability on the hottest and coldest days of the year, which tend to drive system peaks. This means that when power is used as well as how much power is used has an impact on how much grid capacity is needed to reliably meet demand. CMP's net peak electric demand was 1,745 MW in June 2025, while average electric demand over the year was 1,045 MW. As electric demand continues to grow, driven by the shift from fossil fuels to electric vehicles, heat pumps and other electric end uses, electric network infrastructure will need to be upgraded and expanded to accommodate the increased load.

However, whether and how that demand is managed will have implications for the extent of grid upgrades needed. For example, if potentially flexible load such as EV charging occurs at the same time that air conditioners or heat pumps are running at full capacity on the hottest or coldest days, while customers are cooking and doing laundry, peak demand will be at the high end of potential demand scenarios. Alternatively, if EV charging occurs overnight and flexible demand, such as heating and cooling is optimized to ramp down when other household appliances turn on, then incremental peak demand from electrification would be lower, potentially requiring fewer upgrades.

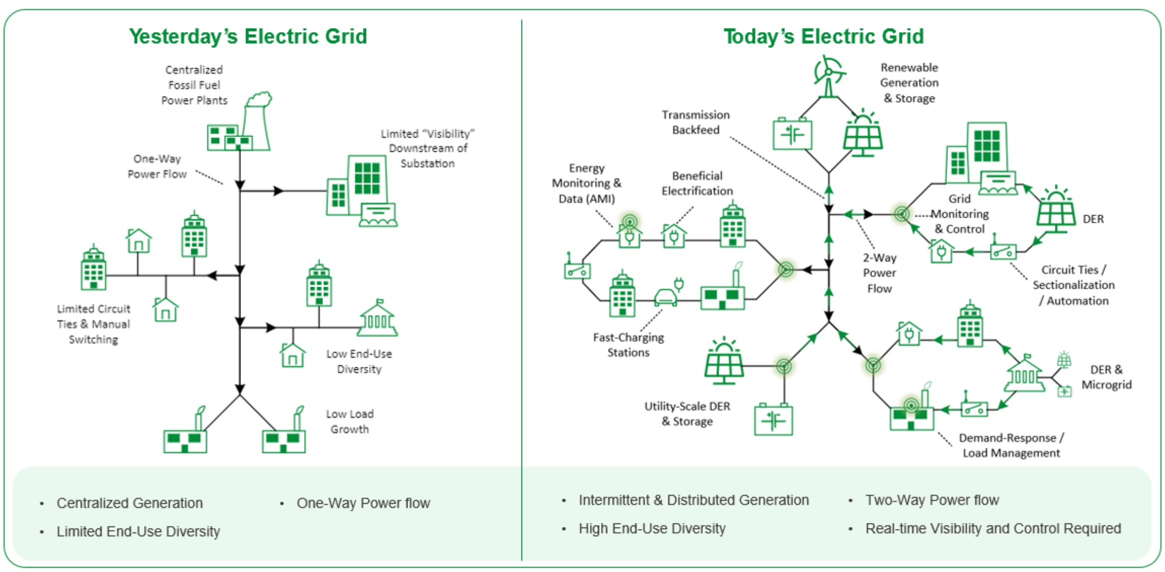
Optimizing grid capacity utilization requires 1) customer adoption of flexible resources and technologies, such as smart thermostats, smart EV chargers and batteries, 2) the communications and technology platforms necessary to coordinate DERs and flexible demand technologies for grid benefit, such as ADMS and DERMS, and 3) customer programs and/or rate design to manage or incentivize optimal usage. CMP's IGP Roadmap recognizes and includes both foundational utility investments, including communication and technology platforms to optimize DERs, as well as coordination with customer programs outside its control. CMP recognizes the importance of collaborating closely with stakeholders including Efficiency Maine Trust (EMT) to maximize the value of demand response programs and load shifting technologies.

Maximizing flexibility to mitigate peak demand can help ensure cost-effective grid investments. Grid investments and operational strategies needed to promote flexible management of consumers' resources and energy consumption are:

Priority 3: Promote flexible management of consumers' resources and energy consumption	**CMP's Key Strategies, Investments and Operations**	**More detail**
Improve forecasting EV load, DER adoption, and climate parameters	CMP's transition to time-series analysis, supporting 8760-hourly modeling, will **incorporate more granular load profiles for DERs, EVs and heat pumps**. The new forecasting platform will also simulate the effects of rate design, managed charging programs and flexible load technologies.	Section 6.1
Support integration and utilization of DERs to enable load flexibility and resilience	Deploy an ADMS platform and DERMS features to **lay the foundation for integration and utilization of DERs**, enabling load flexibility and resilience. ADMS enables near real-time visibility and control of the physical infrastructure of the distribution grid, and a DERMS application would enable monitoring and optimization of DERs.	Section 6.2

Priority 3: Promote flexible management of consumers' resources and energy consumption	CMP's Key Strategies, Investments and Operations	More detail
Technologies or programs to shift load from system peak to reduce Maine's share of the Regional Network Service (RNS) charge	Technologies that can reduce or shift load include battery storage, grid enhancing technologies (GETs), EV charging, smart thermostats, water heaters and smart appliances. Customer programs, such as demand response or managed EV charging, and/or rate design are necessary to manage or incentivize optimal usage. CMP intends to pilot peak shaving battery storage and DER optimization as well as coordinate with EMT's customer programs.	Section 6.2

Achieving these priorities depends upon successful planning to accommodate the changing uses of the grid. While the Company does not own generation or manage customer programs, such as energy efficiency or demand response programs, visibility into distributed generation and customer demand is becoming increasingly important as growing DER penetration and rising demand create more variability and complexity on the grid.



CMP understands the importance of its role in the lives of its customers and aims to provide transparency into the challenges facing the distribution network and ways that network investment and operations must adapt to the impacts of rising demand, increasing renewables, and an increase in the frequency of extreme weather events. Addressing these challenges requires a long-term, forward-looking strategic approach to investment planning and operational improvements enabled by grid modernization and predictive maintenance.

Central Maine Power's vision for the future electric grid is grounded in a simple idea: a resilient, flexible, and modern grid must be built from a strong foundation. The essential work of maintaining safety, replacing aging infrastructure, enhancing data systems, and ensuring reliable day-to-day operations forms the base upon which more advanced capabilities can be responsibly added. At the same time, CMP must advance the data, tools, and analytical capabilities that support planning and operations to enhance system visibility and grid forecasting. As these core investments strengthen the system, CMP can then introduce technology layers such as advanced sensing and controls, flexible interconnections, and other new technologies that expand customer value and grid flexibility.

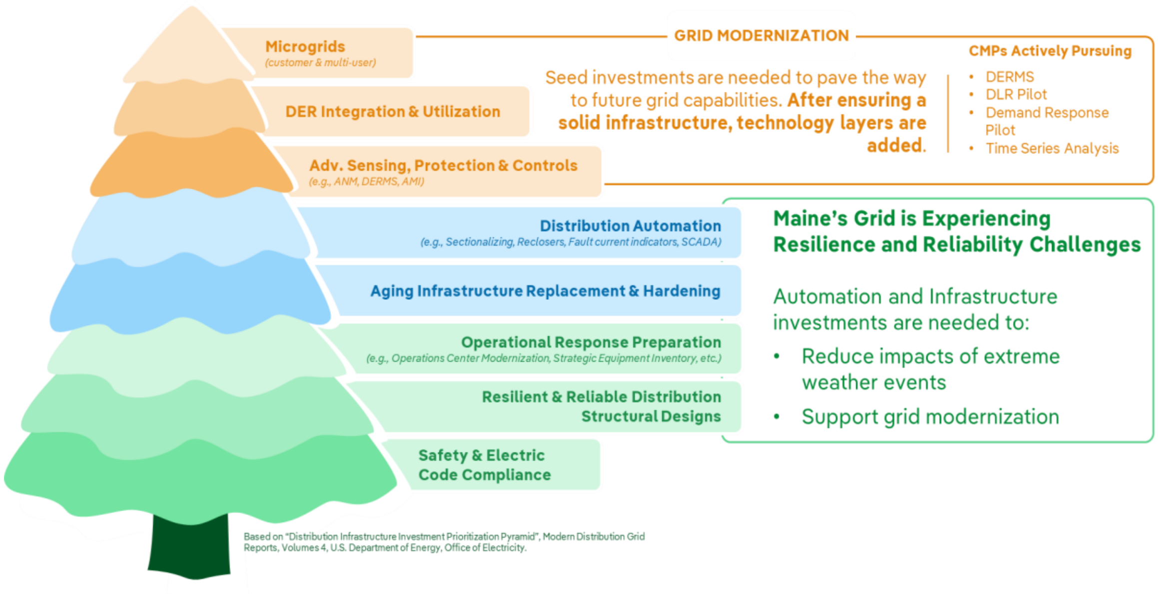
This approach reflects widely recognized industry guidance that modernization cannot occur in isolation or prior to foundational capital and operational needs. As the U.S. Department of Energy notes: "Modern distribution systems are built upon foundational capital and operational investments. Grid modernization investments cannot be planned in a vacuum—they must be aligned with traditional asset planning and integrated with other planning objectives for resilience and reliability.[5]"

CMP's strategy therefore prioritizes foundational investments that both reinforce today's infrastructure and prepare the grid for the transition ahead. By aligning long-term grid planning with emerging customer needs, distributed energy adoption, and the increasing severity of extreme weather events, CMP is building the core system strength required to support a cleaner, smarter energy future for Maine.

The graphic below illustrates this sequential approach, showing how foundational system needs are addressed first to support the layering of more advanced grid modernization capabilities over time. This graphic is based on the U.S. Department of Energy's "Distribution Infrastructure Investment Prioritization Framework."

[5] U.S. Department of Energy. "Modern Distribution Grid DSPx". June 2020.

Exhibit 1.1: CMP's Foundational Investment Framework for Grid Modernization



1.2. Roles of Third-party Stakeholders in the Grid Plan

CMP engages with thousands of customers and stakeholders every year. Those conversations range from questions about how to move service to a new address to policy discussions around rate design, and provide valuable feedback on our work and our customers' priorities. The stakeholders we engaged with, the engagement opportunities, and a summary of feedback and how it was incorporated into the IGP are provided below. Further information on feedback is included in Sections 3, 4, and 5, and in Section 7. Further information on environmental, equity, and environmental justice engagement and feedback is provided in Section 7.

1.2.1. Summary of Engagement Opportunities

April 16, 2024 Stakeholder Meeting

The first stakeholder meeting for CMP's Integrated Grid Plan and Climate Change Protection Plan, held on April 16, 2024, introduced the company's role, regulatory obligations, and the challenges facing Maine's electric grid. CMP outlined its service footprint, reliability issues, and aging infrastructure, noting that low delivery rates correlate with lower reliability compared to peers. The discussion highlighted Maine's climate vulnerability, increasing storm frequency and severity, and the need for proactive resilience measures such as hardening, vegetation management, and automation supported by federal grants. CMP presented its Climate Change Protection Plan, including the Climate Change Vulnerability Study and Resilience Plan, which aim to identify at-risk assets and mitigation strategies. The meeting also covered integrated grid planning as a 10-year roadmap to improve reliability and resiliency while enabling Maine's climate goals. CMP explained its investment planning process, regulatory review requirements, and the importance of balancing affordability, equity, and decarbonization objectives.

Stakeholders were invited to engage in shaping priorities and solutions through a transparent, collaborative process.

August 13, 2024 Stakeholder Meeting

The second stakeholder meeting for CMP's Integrated Grid Plan and Climate Change Protection Plan was held on August 13, 2024, and provided updates on climate resilience efforts and the Climate Change Vulnerability Study, which examines future climate projections and asset risks. CMP explained the difference between mitigation measures, such as electrification, and adaptation measures like hardening and undergrounding. The session reviewed LD 1959 requirements for the 10-year grid plan and outlined priorities set by the MPUC order: reliability and resilience, improved data quality, and flexible resource management. CMP also discussed load forecasting using ISO-NE's CELT report, including 50/50 and 90/10 weather scenarios and seasonal snapshots, and highlighted how these inform planning for reliability and capacity. The meeting concluded with updates on ongoing initiatives, including automation deployment, enhanced design standards, and federal funding to support resiliency and flexible interconnections.

January 27, 2025 Stakeholder Meeting

On January 27, 2025, CMP held its Milestone 1 meeting, which was the first formal milestone of the 18-month IGP process. The meeting was open to the public and more than 50 individuals attended. The meeting focused on technical inputs for system modeling to support a 10-year roadmap for reliability, resiliency, and climate goals. CMP outlined two planning scenarios—low and high adoption of EVs, heat pumps, and DERs—using ISO-NE's CELT forecast disaggregated to CMP's service territory. Weather-based forecasts included 50/50 and 90/10 conditions across six seasonal load snapshots. The session detailed distribution and transmission modeling approaches, generation dispatch assumptions for solar, wind, hydro, and storage, and infrastructure considerations limited to approved projects. CMP also discussed grouping circuits by overload risk and DER penetration for representative analysis, and using ISO-NE's long-term study to validate 2040 readiness. Stakeholder engagement plans were shared, including public meetings, targeted outreach, and online feedback opportunities. The meeting materials were posted on CMP's webpage in advance, and a recording of the meeting was posted online immediately after the meeting.

August 25, 2025 Stakeholder Meeting

On August 25, 2025, CMP held the Milestone 2 meeting, which focused on identifying system needs using inputs developed in Milestone 1. The meeting was open to the public and more than 50 individuals attended. CMP applied ISO-NE's 2024 CELT forecasts under two scenarios—baseline and high adoption with extreme weather—across six seasonal load snapshots. Forecasts were disaggregated to CMP's service territory, revealing faster growth in urban areas and a shift to winter peak dominance by 2027 due to heat pump adoption. The analysis covered 250 substation transformers, 480 circuits, and 70 sample subcircuits, identifying thermal overloads and voltage violations as primary needs, with asset condition and reliability as secondary concerns. Transmission modeling included 18 scenarios across 345kV, 115kV, and 34kV systems. Examples highlighted circuits with overload and voltage issues under different conditions. The meeting concluded with a preview of Milestone 3, which will evaluate solutions such as DERs, storage, automation, and grid hardening using a scorecard approach.

November 25, 2025 Stakeholder Meeting

On November 25, 2025, CMP held the Milestone 3 meeting, which focused on CMP's approach to developing solutions for grid needs identified in earlier phases of the IGP process. The meeting was open to the public and more than 40 individuals attended. CMP explained how needs were categorized by timing, severity, and drivers, and outlined a scorecard-based evaluation framework considering cost, technical performance, reliability, environmental justice, and climate policy alignment. The discussion covered options such as load shifting, circuit upgrades, and battery storage, along with enabling technologies like advanced grid modeling, automation, and forecasting to support future deployment of DERMS, ADMS, and flexible interconnections. Stakeholders raised questions about cost impacts, prioritization, and demand-side measures, and CMP emphasized that pilots for new technologies will precede broader implementation. The session concluded with a roadmap for near-term actions—addressing 166 capacity constraints and deploying automation—and long-term strategies to expand hosting capacity, integrate DERs, and enable time-series modeling for more detailed planning.

Technical Stakeholder Meetings

Although not formally required by the IGP Order, CMP engaged technical stakeholders, including the Department of Energy Resources (f/k/a the Governor's Energy Office) ("DOER"), the Office of the Public Advocate ("OPA"), Efficiency Maine Trust ("EMT"), Natural Resources Council of Maine ("NRCM"), Conservation Law Foundation ("CLF"), Acadia Center, Maine Conservation Voters, A Climate to Thrive, Union of Concerned Scientists, Competitive Energy Services ("CES"), Pacific Northwest National Labs ("PNNL"), Dynamic Grid, Four Directions, Island Institute, Sierra Club, and The Nature Conservancy. Through a total of 20 individual meetings with these groups, usually before the formal milestone meetings, CMP received feedback at all stages of the IGP process from stakeholders who are most familiar with the concepts, but who were also well positioned to advise on presentation content and style to ensure it would be accessible to the broader milestone audiences.

Meetings with Other Technical Stakeholders

At the advice of stakeholders including Maine Conservation Voters, NRCM, CLF, UCS, and DOER, CMP incorporated grid planning priorities topics into engagements with technical stakeholders such as emergency management personnel, municipal officials, and key accounts, to meet these key interests on their own terms and centered on their interests. By engaging on technical topics with technical stakeholders, CMP built a broader and deeper stakeholder engagement than would have been possible with more generic events. Meetings occurring during the IGP process included two "Municipality Day" events, a day-long event focused on emergency management, a day for engagement with nonprofit entities, and dozens of interactions with large business "key accounts."

Community Connection Events

In 2025, CMP held over 70 events across its service territory, assisting more than 300 individual customers. These events take place at town halls, food pantries, YMCA locations, and community action agencies. CMP's team offers information on billing questions, energy usage, storm preparedness, while also helping customers navigate assistance programs and enroll in programs like the Arrearage Management Program and Electricity Lifeline Program. By engaging with customers at familiar locations, and starting with conversations most relevant to their needs and interests, CMP was able to elicit valuable input on customer priorities integral to this grid plan.

Webpage, Email, and Information Availability

CMP created a dedicated webpage[6] to support transparency and accessibility in its grid and climate planning efforts. The site provides an overview of the Integrated Grid Planning process and CMP's Climate Change Protection Plan, along with resources for stakeholders to stay informed and engaged. Visitors can sign up for email updates and submit feedback through a dedicated email address. To ensure equitable access, the webpage also hosts information from the PUC docket for those unfamiliar with the Commission's document system, making regulatory materials easier to find. CMP posted all milestone meeting materials in advance and uploaded recordings after each session, enabling stakeholders, including those unable to attend live meetings, to review content and participate meaningfully. This approach was designed to remove barriers and promote equity in outreach by ensuring that all interested parties could access the same information regardless of technical or procedural limitations.

Continued Engagement

In addition to the engagements above, CMP has also committed to working with the towns of Wiscasset, Islesboro, and Belfast, which is a CEJST disadvantaged community, in coordination with the federal Energy Transitions Initiative Partnership Project (ETIPP), which helps remote and island communities transition to clean energy and improve resilience. In connection with this direct community climate and energy planning work, CMP is also working with the Island Institute to support educational efforts centered on grid planning and operations in rural and coastal communities.

CMP met with each of the federally-recognized Tribes during the grid planning process to discuss both northern Maine transmission, which would be located in an area of state more proximate to formal tribal land holdings, as well as the grid plan docket. CMP also met with Four Directions for a discussion of the grid plan. Feedback from tribal interests centered around opportunities for grid investments to reduce the cost of interconnecting DERs, potential opportunities for collaboration on pilot or local projects eligible for federal funding, and the potential for creative approaches to increased energy sovereignty. CMP will meet again with Four Directions, and a consortium of tribal interests, early in 2026 to continue engagement on these topics.

CMP values the strong engagement from stakeholders throughout the grid planning process and is committed to continuing this collaborative approach. Looking ahead, CMP plans to host a "Resiliency Summit" in 2026, bringing together a diverse group of stakeholders to discuss the many dimensions of grid and community resilience. CMP will also maintain ongoing outreach through key account engagement, "municipality day" events, and continued collaboration with

[6] www.cmpco.com/smartenergy/cmp-grid-and-climate-planning

municipalities and emergency management personnel to ensure local priorities are integrated into planning efforts.

Finally, CMP maintains representation on the Electric Ratepayer Advisory Council, which is charged with evaluating the affordability of electricity in Maine and advising the Public Advocate on potential savings measures; on the board of the Area Agencies on Aging, which are local nonprofits serving older adults, people with disabilities, and their caregivers; on the Energy Working Group of the Maine Climate Council; and on various temporary stakeholder groups focused on energy planning, equity, and climate, such as the DOER's Transmission Infrastructure Study Stakeholder Group.

1.2.2. General Feedback from Stakeholders

Feedback received through the channels established above was incorporated into the IGP. The table below provides an overview of higher-level feedback received from stakeholders during the IGP process. Further detail is provided in Sections 3, 4, 5 and 7.

Feedback Received	IGP Consideration
Reliability is a primary concern to business interests, emergency management, and providers of services to vulnerable populations	Reliability is incorporated into the solutions analysis in Section5, and recommendations of the Climate Change Protection Plan are referenced in Section 4.4
Capacity is a concern, primarily related to the potential interconnection of additional DERs, but also for load growth, especially given the shift to a winter peak	The impact of DER and load growth is included in the forecasting discussion in Section 3, in the needs assessment in Section 4, and in the solutions analysis in Section 5, as well as in the discussion of technology in Section 6.
Inputs to CELT forecast are unclear	The CELT forecast is discussed in detail in Section 3
The 50/50 and 90/10 forecasts are weather based, not electrification forecasts	The IGP Order's direction to use these as proxies for electrification adoption is explained in Section 3
The 2024 and 2025 CELT forecasts are not consistent	The differences and similarities between these forecasts are explained in Sections 3.2 and 3.7
Differences between forecasting and area study methodology for project proposals and the IGP should be explained	Further detail about the level of analysis for each of these objectives is provided in Sections 4 and 5
Technology investments and opportunities for grid utilization, such as battery storage, DERs to offset load, and demand response or load shifting should be incorporated	Underlying enabling technology and grid utilization processes and technologies are discussed in Section 6
Time-series analysis rationale and roadmap should be included	Time-series planning tools and path toward implementation is discussed in Sections 6 and 7

Feedback Received	IGP Consideration
DER-driven needs should be separately identified to ensure that solutions can be identified as potentially customer-funded	DER-drive needs and solutions are identified separately in Sections 5 and 6
Limited role of CMP in overall energy and climate planning should be included	A description of CMP's role as a T&D utility is included in Section 1.1
Contrast between IGP as a planning document and discrete project approvals and cost recovery proceedings should be highlighted	Further discussion of the IGP and actual cost recovery proceedings is included in Section 2.2
Planning should focus on reliability and resiliency, and account for community safety during hazardous weather events	The plan identifies foundational investments in infrastructure and processes and technologies to serve primary needs and to enable technologies that assist with storm response, as well as non-traditional reliability and resiliency upgrades like battery storage or demand response, in addition to hardening to reduce storm impacts
The plan should ensure sufficient capacity for access to distributed generation opportunities	The grid plan's identification of cost-effective capacity solutions to enable DER integration and load growth

1.3. Technology Deployment Strategies

CMP's technology deployment strategy prioritizes foundational and enabling systems that create the operational backbone for a changing electric system. These investments include advanced communications platforms, enhanced data integration, and system control capabilities that enable real-time visibility, predictive analytics, and dynamic load management. Foundational technologies such as AMI, Supervisory Control and Data Acquisition (SCADA), and the Grid Model Enhancement Project (GMEP) improve data quality and integrity, supporting advanced planning and time-series forecasting. Building on this foundation, CMP plans to implement platform technologies like the Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS), which enable critical functions such as Volt/VAR optimization, fault isolation and restoration, and orchestration of distributed energy resources. For example, DERMS will allow CMP to monitor and optimize solar, storage, and flexible loads, facilitating demand response and flexible interconnections that reduce peak demand and enhance system resilience. This layered approach ensures that emerging technologies can be deployed cost-effectively and at scale, while maintaining reliability and preparing the grid for increased load and increasing DER penetration, in accordance with the Pathways to 2040 report and Maine's climate goals.

1.4. Regulatory and Policy Changes

As a regulated distribution and transmission utility, CMP complies with all regulatory orders and policy changes implemented by the Maine Public Utilities Commission (MPUC) and the Federal Energy Regulatory Commission (FERC). Several key FERC orders in the past few years have implications for utility planning. FERC Order 2222, which enables DER participation in wholesale markets, opened up new opportunities for leveraging DERs to reduce the grid peak, reduce costs and enhance grid reliability. The growth in DERs over the past five years is having significant implications on grid planning, and CMP is pursuing foundational platform technologies, ADMS and DERMS, to manage and optimize DERs. FERC Order 2023, which reformed the generation interconnection process with changes such as the "first-ready, first-served" cluster study process, stricter deadlines, and enhanced transparency requirements, aims to address long-standing inefficiencies in interconnection processes and reduce queue backlogs. These changes have introduced significant operational and compliance challenges and necessitate not only procedural adjustments but may also require the adoption of new technologies, enhanced data-sharing capabilities, and organizational alignment to meet compliance obligations effectively. FERC Order 1920 established long-term regional transmission planning and cost allocation processes. While still in the early stages of implementation, the long-term scenario-based planning requirements are aligned with the goals of the Integrated Grid Plan. Exhibit 1.2 below provides a summary of recent regulatory and policy changes and efforts underway to implement the changes.

Exhibit 1.2: Regulatory and Policy Changes Impacting Grid Planning

Regulatory order	Key provisions	Status
Utility role in Distributed Energy Resource (DER) aggregation FERC Order 2222	Enables DER participation in wholesale markets; requires market rule changes for Energy and Ancillary Services	• Energy and Ancillary Services market rules expected to go live November 1, 2026
Generator interconnection reforms FERC Order 2023	Shifts from “first-come, first-served” to “first-ready, first-served” cluster study model; introduces penalties for delays and withdrawals	• ISO-NE compliance filing approved in April 2025 • CMP T&Cs updated to align with FERC order • Transitional Cluster Study underway as of October 2025 • First Official Cluster Study begins Fall 2026
Regional Transmission Planning and Cost Allocation FERC Order 1920	Requires 20-year scenario-based planning every 5 years; mandates state engagement and default cost allocation methods	• ISO-NE granted extension to June 2027 with an effective date 2029 • ISO-NE sought the extension to allow time for implementing and gaining experience from its first Long-Term Transmission Planning (LTTP) Request for Proposals • ISO-NE’s first LTTP RFP builds off of findings of ISO-NE's 2050 Transmission Study and seeks transmission capacity expansion in Southern Maine and upgrades to prepare for 1,200 MWs of land-based wind from Northern Maine

Regulatory order	Key provisions	Status
		• CMP participating in stakeholder discussions as affected system operator (begin Q3 2026)
Ambient Adjusted Ratings (AAR) for transmission lines FERC Order 881	Requires use of AARs to improve transmission line ratings	• Implementation in New England delayed to end of 2026 due to delays in software development • Outcomes of using AARs expected in 2027

Recent federal and state legislative actions, including the One Big Beautiful Bill Act (OBBBA) and Maine's LD 1777, are expected to influence renewable generation development and could decelerate electrification efforts across the region. While CMP has not yet quantified how OBBBA will impact Maine, these provisions may shape future iterations of the IGP as market conditions and policy incentives evolve. Additionally, CMP's efforts to secure external funding for advanced grid technologies have faced setbacks: the proposed FIRM grant (in coordination with the DOER and Versant Power), which included projects for Active Network Management (ANM) and Dynamic Line Rating (DLR), was canceled, and applications for energy storage pilot programs were withdrawn before approval. These developments underscore the need for adaptive planning and continued exploration of alternative pathways to achieve grid modernization and resilience goals.

02.
System Overview

2. System Overview

2.1. Transmission and Distribution System Data

The area served by Central Maine Power Company covers approximately 11,000 square miles in central, western, and southern Maine. CMP serves approximately 675,000 customers in this service area, with a system net peak demand of 1,745 MW. The CMP transmission system is responsible for carrying bulk electricity between generators and ties to the rest of New England and Canada, and throughout the service territory to distribution substations and our customers. CMP's transmission system comprises approximately 2,300 miles of transmission lines.

2.1.1. Distribution System Data

Further detail about the distribution system requested in the IGP Outline at 2.a.a-g is provided in the table below.[7]

Distribution Substation Capacity (kVA)[8]	**3,000,000**
Distribution Substation Transformer Capacity[9] (kVA)	3,000,000
Distribution Line Miles	24,350
Overhead Miles	22,500
Underground Miles	1,850
Customer Meters with AMI	685,559
Customer Meters without AMI[10]	4,516

Asset Condition

Asset condition, driven by age, usage, and storm and climate impacts, affects the ability of the system to provide safe, reliable power. Key asset condition concerns are bare wire conductor, aging and weak poles, and the broader health of distribution line equipment, transformers, and substations.

Approximately 90% of CMP's distribution lines are constructed with bare wire. Bare wire is highly vulnerable to tree contact, which is the leading cause of outages on the distribution system. Deploying bare wire was the industry standard when much of CMP's system was built, but it is no longer the prudent choice for Maine's heavily forested landscape with increasingly frequent extreme weather events. Modern covered conductor technology—including tree wire and spacer cable—is significantly more resilient to tree contact compared to bare wire, offering the opportunity to reduce both the frequency and duration of outages for customers.

[7] Section 2(a)(f) of Attachment C to the IGP Order requests the "total number of distribution premises." This is not a quantity CMP tracks, however we note that while total customers is approximately 660,000, total meters is approximately 690,000. If "distribution premises" should be interpreted as unique customer locations, then total customers is most likely a dependable approximation.
[8] Distribution substation capacity is not separately tracked from distribution transformer capacity because they are equal.
[9] The capacity of distribution transformers is approximately equal to the capacity of substations.
[10] These remaining meters are typically associated with unique technical, geographic, service-specific constraints, or customers who choose to opt out of AMI meters under CMP's approved opt-out program. These customers are offered a non-communicating digital meter and are subject to a monthly fee approved by the Maine Public Utilities Commission.

In addition, 99% of CMP's distribution poles are wood, making them more susceptible to breaking during storms. Class 3 and 4 wooden poles, like bare wire, were once the industry standard when much of CMP's system was constructed. However, these smaller-class poles are no longer the best choice for Maine's densely forested areas and worsening storm conditions. For example, a single storm in December 2023 resulted in over 1,000 broken poles, causing widespread and prolonged outages for customers. A transition to stronger wood poles and steel poles provides increased resistance to storm impacts as well as to wood decay and insect damage, as described in CMP's Climate Change Protection Plan.

Furthermore, CMP's distribution system is aging and, as discussed, was designed for conditions different from today's modern electric system which faces increasing load, two-way power flow, and more frequent, intense storms. For instance, as of December 2024, 143,473 poles (21.5%) are over 50 years old, reaching an age where failure rates begin to rise.

More information regarding CMP's most recent Transmission and Distribution Asset Health Reports can be reviewed under protective order in Docket No. 2024-00014.

Reliability

System-wide reliability over the past five years is shown below in Exhibit 2.1. System Average Interruption Frequency Index (SAIFI) represents the number of times the average customer was out of power, and System Average Interruption Duration Index (SAIDI) represents the total hours the average customer was out of power. For example, in 2024, the average customer experienced 1.83 outages for a total of 3.59 hours.

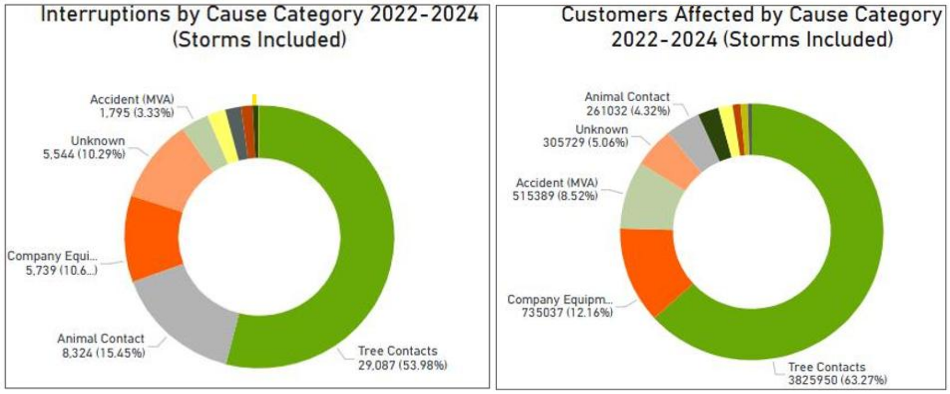
Exhibit 2.1: CMP SAIDI and SAIFI over the past 5 years

Year	2020	2021	2022	2023	2024
SAIFI	2.05	2.02	1.71	1.82	1.83
SAIDI [11]	3.68	3.66	2.87	3.17	3.59

The main challenges influencing reliability metrics are storms and tree cover. As shown in Exhibit 2.2 below, trees contacting power lines are the leading cause of outages on CMP's distribution system, accounting for over 60% of all customer service disruptions between 2022 and 2024 including during major storms. The density and proximity of trees to distribution lines combined with the increasing frequency of severe weather events make maintaining reliable service especially difficult. As mentioned above, CMP's plan to utilize modern covered conductor technology for future upgrades will reduce both the frequency and duration of tree related outages for customers.

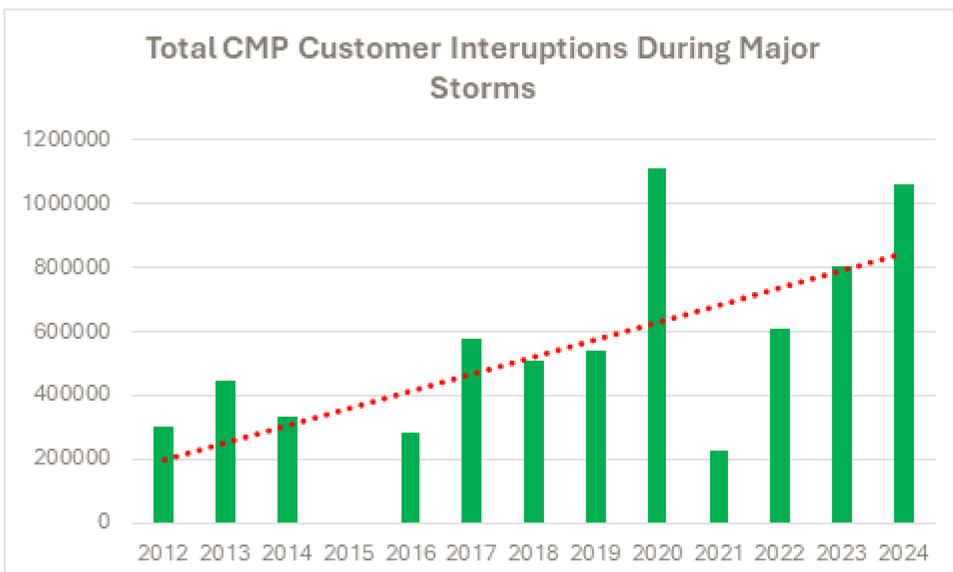
[11] Measured in hours.

Exhibit 2.2: Interruptions and Customers Affected, by Cause



Similarly, CMP has observed increasing impacts from major storms over the past 10+ years. Major storms are those defined using IEEE Beta Methodology, which uses system reliability metrics, specifically System Average Interruption Duration Index (SAIDI), to define "major event days." Like covered conductor, steel poles will help mitigate impacts from major storms.[12]

Exhibit 2.3: CMP Customer Interruptions During Major Storms

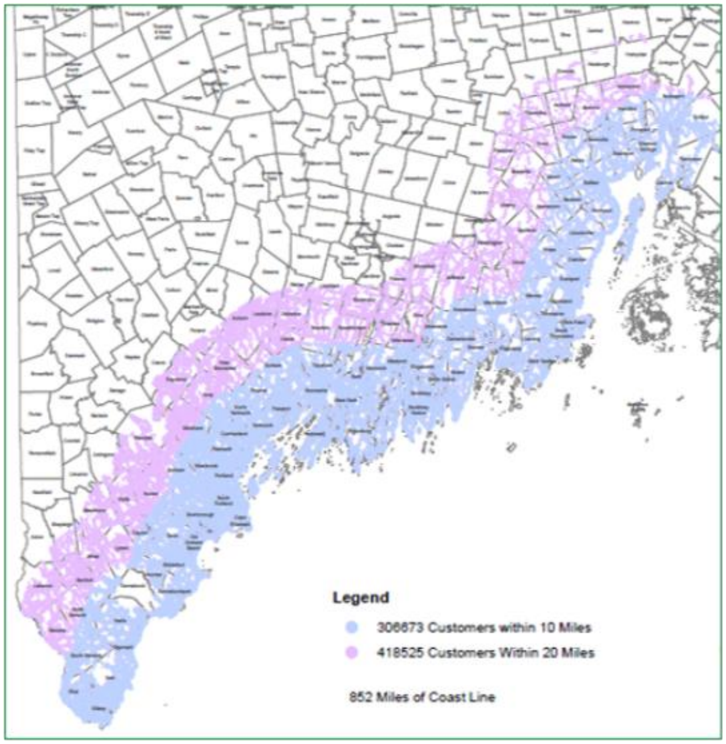


Additionally, CMP's distribution network consists primarily of long radial distribution lines built to meet the needs of a predominantly rural service area. These lines are considered "radial" because they extend from a single generation source and have no backup supply at the

[12] As explained in its October 10, 2025, Testimony, filed in Docket 2025-00270, CMP expects that is continued deployment of distribution automation will cause its Customer Average Interruption Duration Index (CAIDI) to mathematically rise. CAIDI measures the average duration per customer interruption and is calculated by dividing the total customer interruption duration by the total number of customer interruptions. Distribution automation can result in certain customers being restored in less than five minutes, turning what would have been a relatively short outage duration for those customers into a momentary outage (less than five minutes) that is excluded from the CAIDI calculation altogether. This means the CAIDI calculation's denominator—the total number of customer interruptions—decreases. When the number of affected customers decreases and the durations of the sustained outages are not reduced at the same rate, the CAIDI value can increase—even if restoration times are faster and fewer people experience outages.

remote end of the line; thus, an interruption close to the upstream source impacts all customers downstream of that location. CMP has 69 distribution circuits that exceed 100 miles, the longest of which exceeds 250 miles, highlighting the vast geographical area that can be covered by a single radial line and the vulnerability of downstream customers to a service disruption close to the source. The coastal peninsulas and islands served by CMP, such as Belfast and Islesboro in the Rockland Area shown below in Exhibit 2.4, are examples of long radial circuits that pose these unique reliability challenges.

Exhibit 2.4: Customer Density Along the Coast



2.1.2. Advanced Metering Infrastructure

CMP was one of the first utilities in the nation to implement AMI at scale. Beginning in 2010, CMP deployed over 685,000 AMI or “smart meters” across its residential, commercial, and industrial customer base. This early investment was made possible through a combination of federal funding from the Smart Grid Investment Grant (SGIG) Program and CMP investment, totaling $192 million. Today, 99.3% of CMP’s customers are served by AMI meters.

The initial AMI deployment introduced a range of functionalities, including remote meter reading, outage and restoration notifications, voltage monitoring, and remote connect/disconnect capabilities. Customers gained access to a web portal for viewing energy usage and managing consumption, while CMP leveraged AMI data to reduce estimated bills, improve outage response, and lower operational costs through reduced truck rolls and enhanced theft detection.

When CMP first deployed smart meters between 2010-2012 CMP was informed by its vendor that the meters were expected to have an average operational life of approximately 15-20 years. While many of the original fleet of AMI meters continue to operate reliably, CMP is experiencing an increasing number of meters reaching end of life, including communication issues, display malfunctions, and complete device outages. In 2023, CMP retired 4,658 meters due to end-of-life conditions. In 2024, approximately 11,000 meters were retired, and for 2025, the company anticipates that asset lifecycle considerations and operational reliability will lead to the retirement of at least 13,000 meters. All new meters ordered will include batteries and support time-of-use (TOU) compatibility.

While the original AMI deployment delivered significant operational and customer benefits, the underlying technologies—particularly in communications and data management—have evolved considerably over the past decade.

Although core functions of AMI allow remote meter reads, facilitate billing, and assist with outage management, efforts to integrate AMI meter data into planning and modeling functions, as described in Section 6.1, would further leverage technology improvements in support of the IGP Priorities.

In the near-term, CMP will continue to replace meters as needed while evaluating the need for a new phase of AMI investment focused on modernizing infrastructure and expanding system capabilities. To enhance telecommunications infrastructure and ensure seamless signal transmission between AMI and applications, CMP completed the upgrade of all 61 Gateways in 2025, enabling more reliable data collection. In addition, CMP is working to upgrade the core routers as part of this broader initiative.

2.1.3. Existing and Planned Modeling Software

Refer to Section 4.1 for a description of existing modeling software and Section 4.5 for a description of planned modeling software.

2.1.4. Distribution Automation, Monitoring, Control and Visibility

Distribution automation refers to smart grid technology that works by installing devices that have full communication and remote-control capabilities, such as Supervisory Control and Data Acquisition (SCADA) switches and reclosers. These devices can then be operated remotely through CMP's Energy Control Center (ECC) using SCADA from its Energy Management System (EMS) in conjunction with an integrated Outage Management System (OMS). ECC operators can control switching where SCADA is available during an outage in real time, which can reduce outage restoration times to customers and improve reliability. In this way, automation can improve reliability and enhance service quality in a safe, efficient, and cost-effective manner. In 2022, CMP's ECC completed an expansion of a new Distribution Operations Center (DOC), which created a contemporary distribution control room from a legacy dispatch center with implementation of SCADA linked with an Outage Management System in 2024 allowing DOC operators enhanced control of the distribution system in real-time for outage management and maintenance of the grid.

Currently approximately 15% of CMP's distribution circuits do not have SCADA, and for the 85% of circuits that do have SCADA, SCADA visibility is limited by the number of devices on the circuit. Adding SCADA devices at strategic locations as part of the Distribution Automation program will give engineers better data and visibility to the distribution system and therefore allow for enhanced accuracy during distribution analyses, while also enhancing reliability and reducing outage durations. Where SCADA is not available at the substation, manual readings are collected on a bi-monthly basis to track circuit load. CMP's line sensor program is targeting substations without SCADA to install sensor devices to collect 15-minute interval load data.

Exhibit 2.5: Percentage of Substations and Feeders with Monitoring and Control

	Percentage with SCADA	Interval Data Collected
Feeders	85%	15-minute
Substations	88%	15-minute

CMP began a distribution automation program in 2023, which included installing 452 three-phase devices and 27 single-phase devices between 2023-2025. By the end of 2025, CMP completed the distribution automation project for the entire Alfred service center (three-phase), 70% of the Brunswick service center (three-phase), and roughly 43% of the Portland service center (three-phase). CMP prioritizes the installation of distribution automation devices by worst performing service territory, using three-year SAIFI data (excluding major storms).

Installation of all distribution automation devices (roughly 2,800 total, including both three-phase and single-phase devices) across its entire service territory is expected to be completed by 2031. A portion of the devices will be installed as part of the federal grant award titled "DOE Grid Resilience and Innovation Partnerships (GRIP) Grant Project – Enhancing Utility Resiliency in America's Most Forested State," which focuses on expediting the installation of distribution automation across disadvantaged communities ("DACs"). As part of this grant project, 335 distribution automation devices will be installed, consisting of 300 three-phase devices and 35 single-phase devices.

To meet the increasing customer expectations for fewer disruptions and shorter outages and the increasing challenges facing the system, CMP needs to expedite the rate at which distribution automation devices are deployed throughout its service territory. Therefore, CMP intends to enhance its approach to the distribution automation program by increasing the deployment of three-phase devices to be 100% complete with three-phase by 2028 for the entire CMP service area.

CMP's distribution automation program aims to reduce customer counts between protective devices to 300-500 customers, which will greatly reduce the number of customers impacted by an unexpected outage on a circuit. Currently, there is no standard for numbers of customers between distribution protective devices, so an outage could impact the entire circuit and therefore all customers supplied by that circuit.

Distribution automation also allows better data for distribution planning analyses. Adding SCADA devices as part of the distribution automation program will give engineers hourly interval data and the ability to gather data remotely from these SCADA devices, throughout the entire circuit. In addition, CMP plans to integrate SCADA data into CYME, giving distribution planning better visibility into the distribution grid and therefore allow for enhanced accuracy during distribution analyses.

2.2. Financial Data

2.2.1. Historical and Projected Distribution and Transmission Investment Broken Down by Category

The investment categories described below, along with drivers of change between historic and forecasted investment for each category, apply to both historical and projected investment for each distribution and transmission.

Reliability: Projects and programs impact continuity and quality of service to meet service targets and are intended to provide safe, reliable service, including meeting basic regulatory service targets such as SAIFI, CAIDI, and customer service. Examples of programs and projects under this category include improvements to worst performing circuits, transmission, distribution, and substation hardening, power quality, and line inspection mitigation.

Over the next five years, CMP's investment strategy will be shaped by the increasing frequency and severity of storms and climate-related hazards, particularly in coastal and forested regions of Maine. These events have amplified outage impacts and restoration costs, prompting a shift toward more resilient infrastructure. Tree-related disruptions account for over 60% of customer outages and are driving the deployment of covered conductors, targeted undergrounding, vegetation-resistant designs and other resiliency measures identified in CMP's Climate Change Resilience Plan. Key drivers include:

- Backup circuit tie program: CMP's long radial circuits, many of which lack redundancy, correlate with elevated SAIFI and SAIDI metrics. Expanding backup ties and sectionalization capabilities can limit the damage of storms or other impacts to fewer customers.
- Distribution Automation: Completing the installation of distribution automation, including SCADA-enabled devices and self-healing technologies, will improve outage response and restoration speed. A portion of the devices will be installed as part of the DOE Grid Resilience and Innovation 4 Partnerships (GRIP) Grant Project, which focuses on disadvantaged communities.
- At the transmission level, the major planned projects listed above contribute significantly to forecasted reliability investment.

Asset Condition: A significant portion of CMP's infrastructure was built out during the mid twentieth century. Today, many critical assets are reaching their "end of life" and requiring replacement. "End of life" replacements are driven by the risk and consequence of failure, obsolescence, lack of replacement parts, and other technical issues. They are prioritized based on the cost associated with on-going repair and maintenance, the asset's probability of failure, the criticality of the asset, and the risk associated with the failure of the asset. In parallel with the deployment of new grid technologies and strategies, foundational infrastructure must be replaced to prevent failure.

Asset condition and aging infrastructure present another critical challenge. Approximately 90% of CMP's distribution wire remains bare, and 99% of poles are wood, with a significant portion of poles and substation equipment exceeding 50 years in age. This aging asset base is driving accelerated replacement programs, including steel pole installations and substation transformer upgrades. Compounding these issues are extended supply chain lead times which often exceed two years for key equipment and necessitate earlier procurement and multi-year planning. Key drivers of investment include:

- Distribution Line Inspection Program: This program involves regular inspections of distribution lines and poles to identify and address damaged equipment or vegetation encroachments.
- Substation Hardening: Substation hardening projects address substation asset health concerns to reduce risk of significant customer outage events. Projects are prioritized based on CMP's comprehensive substation survey results and other identified reliability issues.

Customer Focus: Projects driven by customer needs or required to maintain or upgrade customer services. Customers include end-use customers, municipal agencies, elected officials, regulatory bodies, investors, media, and union leaders. These projects and programs include, but are not limited to, individual home service connections, highway relocations, Distributed Generation (DG) installations/modifications, and street lighting conversions. Customer contributions in aid of construction (CIAC) offset (are subtracted from) CMP capital investment in the summary tables below. New generation customers and commercial and industrial load customers are generally responsible for the cost of any upgrades required to interconnect.

Customer connection growth, driven by residential and commercial development, is increasing demand for line extensions and service upgrades. Regulatory obligations related to broadband pole attachments are also expected to surge, requiring make-ready work and compliance with evolving standards. Additionally, CMP expects to replace over 18,000 AMI meters in 2025. Investments in fleet and facilities are planned to support storm restoration, internalized construction, and modernization of end-of-life building systems, with a focus on safety, security, and energy efficiency.

Another key driver is addressing system capacity constraints. As described in Section 5, CMP anticipates significant system capacity constraints over the next five years, driven by electrification trends including the adoption of electric vehicles, heat pumps, and distributed energy resources (DERs), aligning with ISO-NE's 2024 CELT forecasts. Both winter and summer peak loads are projected to rise materially, placing stress on existing infrastructure.

Safety: Projects and programs impact public and employee safety by lowering the risk of accidents and injuries or maintaining current safety levels. This category also includes projects that enhance or maintain physical or cybersecurity. (Maintenance and replacement of building security systems, cyber security programs, HR equipment and training)

Timely and necessary investment in electricity infrastructure is critical not only for system reliability and capacity but also for ensuring the safety of customers, utility professionals, and the public. Safety considerations are embedded in regulatory frameworks and industry standards that govern the design, operation, and maintenance of electrical systems.

At both the distribution and transmission levels, safety investment is forecasted to decrease over the period 2026-2030 vs 2020-2024. This is a result of increased investments in asset condition, customer focus, reliability, and strategic and efficiency that additionally provide safety benefits, reducing the total need for safety investment. The remaining investment is targeted at physical (fire protection, tools, streetlight, etc.) and cyber security investments.

Strategic and Efficiency: Projects and programs improve the efficiency of business operations and support the integration of new technologies and systems.

The rapid proliferation of DERs, particularly distributed solar, is transforming grid utilization and increasing operational complexity. Bidirectional power flows are challenging traditional voltage control and fault isolation practices, requiring a shift from reactive to proactive, data-driven operations. CMP plans to invest in an enhanced EMS and deploy an ADMS platform that incorporates Volt-VAR Optimization (VVO), Fault Location, Isolation and Service Restoration (FLISR), power flow, and Distributed Energy Resource Management System (DERMS) functions.

To support dynamic planning and operations, CMP is leveraging AMI and SCADA data to enable circuit-level, time-series forecasting. Tools such as MetrixIDR are being used to simulate scenarios involving EVs, heat pumps, and solar adoption, aligning with Integrated Grid Planning (IGP) priorities and informing the selection of non-wires versus wires solutions. These investments are designed to maximize the return on prior automation deployments by layering in analytics and forecasting capabilities that enhance outage response, reduce system losses, and support dynamic hosting capacity.

Historical Distribution Investment for the Past 5 years

Distribution system investments over the past five years have been primarily driven by reliability and resiliency focused improvements, including distribution automation, steel poles, and covered wire, and asset condition, as CMP works to address aging infrastructure. Increasingly severe storms over the past five years resulted in high storm restoration costs, particularly in 2022-2024, and have driven a need to proactively invest in hardening the grid. The Distribution Line Inspection program, which involves regular inspections of distribution lines and poles to identify and address damaged equipment or vegetation encroachments, scaled up over the past five years to both respond to and prepare for increasingly severe storms.

System capacity projects were a relatively small share of distribution investments over the past five years, and capacity investment was primarily driven by upgrades to the Goosefare and Biddeford Pump substations. Drivers for Safety investment over the past five years include a multi-year cyber security project, an increase in IT and facilities work in 2021, and a Customer Service Technology program in 2024, which includes enhanced protection of customer data. Strategic and Efficiency investments were driven by Spectrum Energy Management System (EMS) implementation, AMI upgrades, fiber telecom projects, and GMEP.

Exhibit 2.6: Historic Distribution Capex for the Last 5 Years

HISTORIC DISTRIBUTION CAPEX FOR THE LAST 5 YEARS ($M)					
Investment categories	**2020**	**2021**	**2022**	**2023**	**2024**
Reliability	$76.5	$68.9	$104.9	$110.2	$86.2
Asset Condition	$39.6	$53.1	$33.7	$62.1	$69.3
Customer Focus	$20.6	$32.7	$41.2	$28.3	$29.1
Safety	$8.0	$20.3	$5.6	$6.7	$21.9
Strategic and Efficiency	$13.2	$6.0	$6.4	$9.5	$14.0
Grand Total	**$157.9**	**$181.0**	**$191.8**	**$216.9**	**$220.6**

Historical Transmission Investment for the Past 5 years

Transmission investment grew by a compound annual growth rate of 4% over the past five years and was primarily driven by reliability and asset condition projects. Major projects driving investment in these categories included, Biddeford Pump Substation Rebuild (in construction), Highland Substation Rebuild (in engineering), Bolt Hill Substation Rebuild (in engineering), Forest Ave Substation Rebuild (complete), CMP Section 80 Line Rebuild (complete), CMP Section 1 Line Rebuild (in construction), and CMP Section 31 Line Rebuild (in engineering).

The Transmission Automation Program was the main driver of Strategic and Efficiency investment in 2024.

Customer Focus investment remained a relatively small share of overall investment, as customer contributions in aid of construction (CIAC) covers most customer-driven upgrades. In 2021, CIAC exceeded other customer-driven project investment due to timing of receipts and applications.

Exhibit 2.7: Historic Transmission Capex for the Last 5 Years ($M)

HISTORIC TRANSMISSION CAPEX FOR THE LAST 5 YEARS ($M)					
Investment categories	**2020**	**2021**	**2022**	**2023**	**2024**
Reliability	$57.7	$40.6	$45.2	$57.0	$73.1
Asset Condition	$51.4	$23.1	$25.0	$36.9	$44.8
Customer Focus	$5.7	-$2.1	$3.6	$8.0	$2.1
Safety	$11.5	$8.0	$4.4	$6.1	$8.9
Strategic and Efficiency	$8.7	$1.6	$2.6	$8.8	$37.9
Grand Total	**$134.9**	**$71.2**	**$80.8**	**$116.9**	**$166.8**

Projected Distribution Investment for the Next 5 years

Over the next five years, increasing peak demands driven by electrification, increasing complexity of a bidirectional grid, stronger, more frequent storms, and aging infrastructure are driving a need for more proactive investment to deliver safe and reliable power for Maine communities and to ensure that the condition of CMP's infrastructure enables progress toward achieving the State's energy goals. Without strategic, generational investments in resilience, these challenges will only worsen over time, leading to higher restoration costs and longer service disruptions for customers.

At the same time, electric demand is rising throughout CMP's distribution system, driven by electrification and new customer needs, described in Section 4. The needs assessment in Section 4 provides an overview of the significant grid constraints projected over the next 5 years. Proactive and strategic investments to increase capacity, distribution system enhancements, and advanced grid planning and management tools are needed to facilitate customer electrification and to strengthen grid reliability and resiliency. Any investments identified in this IGP are subject to change based on evolving grid conditions and are contingent upon obtaining all required regulatory approvals.

Exhibit 2.8: Projected Distribution Investment for the Next 5 Years

PROJECTED DISTRIBUTION INVESTMENT FOR THE NEXT 5 YEARS					
Investment categories	Forecast Capital Investment ($M)				
	2026	2027	2028	2029	2030
Reliability	$130.04	$200.95	$231.12	$177.77	$219.62
Asset Condition	$109.85	$78.21	$79.75	$91.10	$101.00
Customer Focus	$100.67	$123.93	$131.45	$192.50	$186.88
Safety	$8.58	$7.14	$5.15	$6.49	$5.00
Strategic and Efficiency	$18.86	$15.77	$19.53	$40.14	$36.50
Grand Total	**$368.00**	**$426.00**	**$467.00**	**$508.00**	**$549.00**

Projected Transmission Investment for the Next 5 years

Transmission projects take many years to plan, design, permit and construct, and CMP has projects in varying stages of development that are expected to be designed and constructed over the next five years. These include new dynamic reactive devices at several locations, sub-transmission line rebuilds, substation modernization projects, as well as larger CPCN projects for transmission planning area studies where large reliability reinforcements are necessary based on criteria identified by MPUC docket 2011-494. These projects include new substations, replacing existing substations with new, additional 34.5kV and 115kV transmission lines to allow redundancy within a load serving area and upgrades to address voltage collapse. Major projects planned over the next 10 years, dependent on MPUC approval, include:

- Highland Substation rebuild and synchronous condenser, driven by reliability and capacity needs: Approved in Docket 2023-268 and under construction, estimated in-service date December 2029
- Bolt Hill Substation rebuild, driven by reliability, capacity, and asset condition needs Approved in Docket 2024-308, estimated in-service date 2029.
- Greater Portland transmission upgrades: New transmission lines and substation upgrades driven by reliability, capacity, and asset condition needs. These upgrades are pending approval in Docket 2025-276.

- Detroit-Guilford area substation and subtransmission upgrades: Driven by reliability and capacity needs. Pending approval in Docket 2025-166.

Exhibit 2.9: Projected Transmission Capex for the Next 5 Years

Investment categories	Forecast Capital Investment ($M)				
	2026	2027	2028	2029	2030
Reliability	$108.7	$151.5	$160.6	$134.5	$144.6
Asset Condition	$117.4	$159.8	$51.3	$37.6	$52.6
Customer Focus	$30.7	$11.3	$25.1	$2.6	$1.1
Safety	$4.4	$3.8	$3.3	$3.7	$3.5
Strategic and Efficiency	$11.9	$13.8	$15.5	$22.0	$21.8
Grand Total	**$273.1**	**$340.3**	**$255.8**	**$200.4**	**$223.7**

2.2.2. Planned Distribution and Transmission Capital Projects

See Appendix C for a list of planned distribution and transmission capital projects, including project type, drivers, and estimated in service dates for projects presented or granted regulatory approvals. Fully customer funded upgrades and reactive programs that address emergent needs rather than planned upgrades are not included.

2.2.3. Preliminary Cost Recovery Plans and Regulatory Approvals

The cost recovery and regulatory approval schemes detailed in this section are an important reminder that this IGP is not a cost recovery proposal, and additional review, stakeholder participation, and approvals are necessary. Those additional layers of review and approval ensure that changing conditions on the system are accounted for, and provide further opportunity for site-specific analysis to determine appropriate and cost-effective solutions.

Distribution projects are submitted annually to the MPUC in the Annual Planning Study, a five-year schedule outlined in Title 35-A, Section 3132-B. Cost recovery of distribution projects will be sought through distribution rate cases with the MPUC.

Small transmission projects falling under Section 3132-B are included in the Annual Planning Study with Distribution projects. Transmission projects and subtransmission projects subject to Section 3132-A are submitted to the MPUC in Request for Approval filings. Large Transmission line projects subject to Section 3132 require Certificate of Public Convenience and Necessity (CPCN) from the MPUC. Additionally, a five-year schedule of transmission line rebuild and relocation projects and minor transmission line projects subject to 3132(3) and 3132(3-A), respectively, are filed annually in the Ch. 330 filing, along with a five-year schedule of planned substation work over 69kV pursuant to Ch. 308 of the Commission's rules. For transmission projects requiring ISO-NE approval, ISO-NE i.3.9 is a statement received at completion of a proposed plan application assessment. This Proposed Plan Application (PPA) process occurs based on planning procedure with the intent of ensuring a system change has no adverse impact as defined in the ISO-NE transmission planning technical guide and is utilized when a project is looking to interconnect to the ISO-NE system, or a utility company is adding equipment that needs to ensure no adverse impact. Outside of asset condition projects, transmission cost allocation is utilized when ISO-NE identifies regional need based on a needs assessment and is applicable to pool transmission facility equipment only. Transmission rate recovery will be sought through the Transmission Cost Allocation (TCA) process through ISO-NE for all PTF investment greater than $5M and the FERC formula rate annual true up process for all transmission investment.

2.3. DER Deployment

2.3.1. Current DER Deployment by Type, Size, and Geographic Dispersion

CMP has seen significant growth in distributed generation (DG) over the past five years, from less than 100 MW at the end of 2020 to 1,002 MW of installed DG capacity in CMP's service territory as of September 2025, a high penetration relative to CMP's 2025 peak demand of 1745 MW and average demand of 1,045 MW. Distributed generation is projected in the 2034 CELT forecast to continuing growing and is forecasted to reach approximately 1,600 MW within CMP's service area by 2034.

The electric grid infrastructure was historically built to facilitate one-way power flows from large power generators to homes and businesses. With the increase of distributed energy resources (DERs), the role of distribution is shifting from strictly one-way power delivery to a system that can both deliver and receive power, accommodating two-way power flows. DERs can provide energy and services to the lower-voltage distribution grid and include technologies such as solar PV, battery storage, small scale hydro or small scale wind.

The majority of DER projects installed in CMP's service territory and in the queue are distributed solar projects.

Exhibit 2.10: Current DER Deployment by Technology

Technology	Capacity Connected (MW)
Solar PV	938.5
Combined Solar + Storage	41.72
Standalone Storage	5.50
Hydro	5.68
Wind	5.14
Other	5.09
Total	**1,001.7**

Significant growth in the deployment of intermittent DERs over the past five years has added complexity to the grid. Without tools and capabilities to provide real-time visibility and operations, the rapid growth in DER penetration has begun to create operational challenges on the grid. For example, CMP has seen 145 circuits and 108 transformers with reverse power flow just in the past year.

In just the past five years, CMP's distribution system has moved from low to moderate to high DER penetration, as shown in Exhibit 2.11 below. Generally, low DER adoption (<5% of peak demand) can be accommodated without material changes to distribution infrastructure, planning and operations. Moderate levels of DER adoption drive a need for grid modernization to enable visibility and operational use of DERs. High levels of DER adoption create a need for foundational communications and DER management technologies to better integrate and optimize DERs.

Exhibit 2.11: Current DER Deployment by Size (# of projects)

Technology	<250 kW	250-500 kW	500-1000 kW	1000-2000 kW	2000-5000 kW	>5000 kW	Grand Total
Solar	16361	35	70	29	136	5	16636
Combined Solar/Storage	120	0	0	1	9	0	130
Standalone Storage	0	1	0	0	1	0	2
Hydroelectric	7	2	1	0	1	0	11
Wind	175	0	0	0	1	0	176
Other	48	1	1	0	1	0	51
Grand Total	**16711**	**39**	**72**	**30**	**149**	**5**	**17006**

Exhibit 2.12: Cumulative Installed DG Capacity

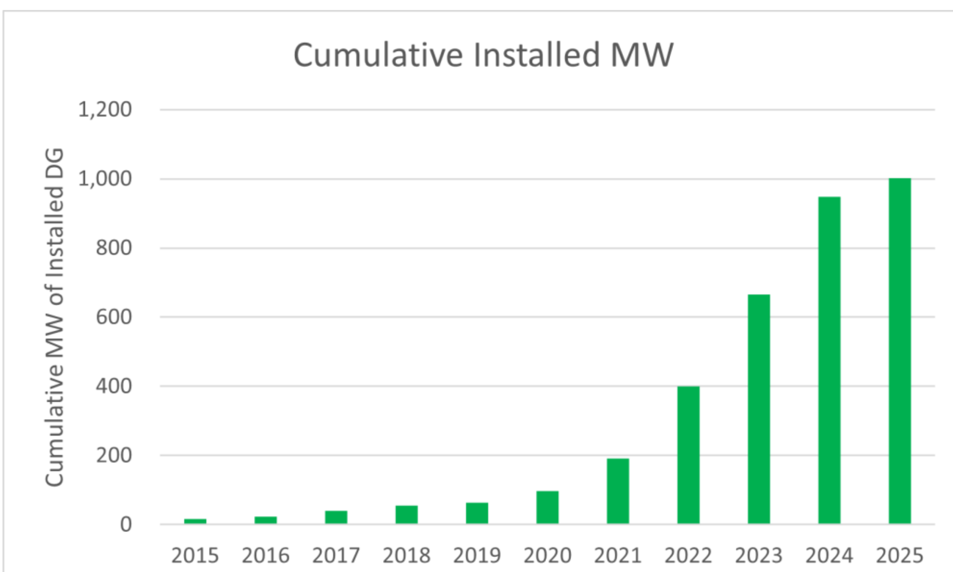
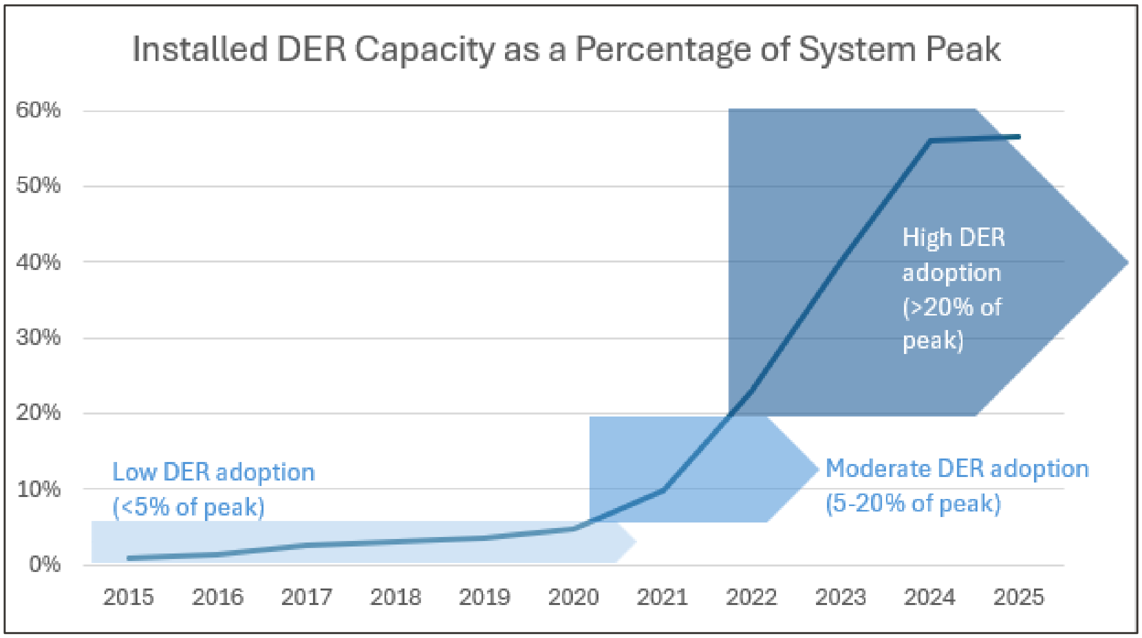


Exhibit 2.13: Installed DER Capacity as a Percentage of System Peak[13]



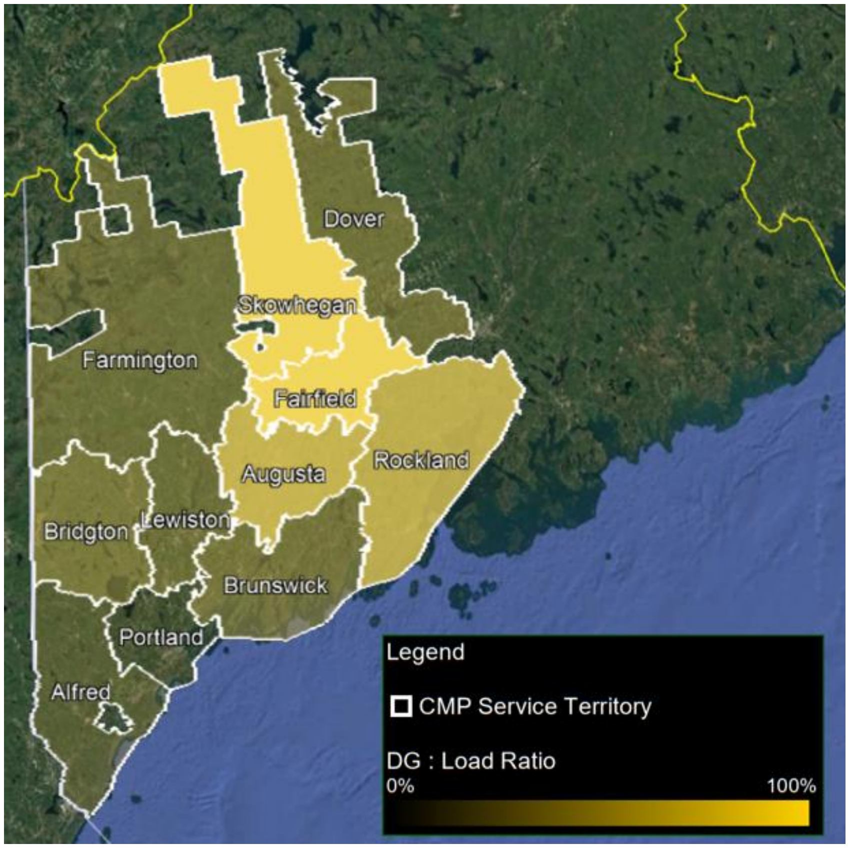
CMP is seeing DG installations across its service territory impacting its system in different ways. The regions with the highest DG installed capacity are Augusta, Alfred, Fairfield and Rockland. However, the impact of DG in Alfred, where DG capacity is 34% of peak load is different than in Fairfield, where the penetration is 99% of peak load. In more rural areas, such as Fairfield and Skowhegan, the high penetration of DG as a percentage of load can result in DG output exceeding demand during certain times of the year and day, for example during the middle of the day in spring and fall shoulder months.

Exhibit 2.14: Geographic Dispersion of DG by CMP Service Divisions

Division	DG Capacity (MW)[14]	Peak Load (MW)[15]	DG Penetration[16]
ALFRED	131.4	362.3	34%
AUGUSTA	130.5	153.4	81%
FAIRFIELD	109.6	104.8	99%
ROCKLAND	107.2	130.2	78%
PORTLAND	105.7	427.5	21%
FARMINGTON	88.4	187.4	45%
LEWISTON	88.3	184.0	46%
BRUNSWICK	80.8	151.5	49%
SKOWHEGAN	73.2	71.0	98%
BRIDGTON	58.1	108.2	51%
DOVER	28.1	57.4	46%

[13] Chart adapted from LBNL presentation at Stakeholder Workshop 3. Paul De Martini. Newport Consulting.
[14] Excludes Level 3 generators and non-renewable generators
[15] Sum of 2024 highest non-coincident circuit peaks
[16] Installed DG capacity as a percentage of peak load

Exhibit 2.15: DG to Load Ratio by CMP Division



2.3.2. DER Deployment for Each of the Past 5 Years

Solar interconnections have grown rapidly over the past five years, with Maine's net energy billing program driving year-over-year growth in new solar interconnections in each year from 2020 to 2024 when Maine's Community Solar market had the second largest volume of installations in the country. The first and only standalone storage project in CMP's territory, a 5 MW utility-scale battery, was interconnected in 2021. Combined solar and storage started to become more prevalent in 2022, providing the benefit of shifting some of the solar system's output to evening and night hours. Hydro and wind are less common at the distribution level, though a handful of small-scale distributed hydro and wind projects have been connected over the past five years.

Exhibit 2.16: Total number of DER projects interconnected to the system in the past 5 years

Technology	2020	2021	2022	2023	2024	2025 (through 10/9)
Solar	927	895	1381	2435	3857	2916
Combined Solar/Storage	2	0	8	7	7	101
Standalone Storage	0	1	0	0	0	0
Hydroelectric	0	0	0	4	1	0
Wind	1	0	0	1	1	0
Other	1	2	1	1	2	2
Grand Total	**931**	**898**	**1,390**	**2,448**	**3,868**	**3,019**

Exhibit 2.17: Nameplate rating of DERs interconnected to the system in the past 5 years (kW)

Technology	2020	2021	2022	2023	2024	2025 (through 10/9)
Solar	29177	88,611	191798	243262	276146	52330
Combined Solar/Storage	15	0	16889	21370	2042	1369
Standalone Storage	0	4,999	0	0	0	0
Hydroelectric	0	0	0	1375	3990	0
Wind	4,500	0	0	2	2	0
Other	15	20	6	18	23	25
Grand Total	**33,707**	**93,629**	**208,693**	**266,027**	**282,203**	**53,724**

2.3.3. Queued DERs

There are 322 MW of DER in the queue as of October 9, 2025, made up primarily of solar PV. While CMP's service territory saw record growth in DERs over the past five years, recent state and federal changes to renewable incentives and compensation may slow the growth of DERs over the next few years. In Maine, a bill was passed in June 2025 that the changed compensation of the net energy billing program for nonresidential customers.[17] At the federal level, the 'One Big Beautiful Bill' Act accelerated the phaseout and rescission of key solar tax credits and funding programs established under the Inflation Reduction Act and in July 2025 the EPA cancelled the "Solar for All" grant that Maine was awarded in April 2024.

[17] LD 1777. An Act to Clarify Tariff Rates for Nonresidential Customers Participating in Net Energy Billing with a Distributed Generation Resource.

Exhibit 2.18: Queued DERs

Technology	Capacity in Queue (MW)	Projects in Queue
Solar PV	275.77	1,878
Combined Solar + Storage	19.71	58
Standalone Storage	19.59	4
Hydro	4.30	2
Wind	0.23	1
Other	2.23	3
Total	**321.82**	**1,946**

2.3.4. Electric Vehicles and Charging Stations

CMP's service territory has 17,710 light-duty EVs in use across a population of 1,051,599, or approximately 17 EVs per 1,000 people. Public charging infrastructure totals 1,055 ports across 435 unique sites, including 779 Level 2 ports and 276 DC fast-charging ports.

Exhibit 2.19: EVs and Charging Stations

Electric Vehicles	Number
Light-duty EVs[18]	17,710
EV Charging[19]	**Number**
Total Public Charging Ports	1,055
Level 2 ports	779
DC fast charging ports	276
Unique public charging sites	435
Estimated Capacity	46.5 MW[20]

2.3.5. Battery Storage

In CMP's service territory, there are 133 interconnected battery storage units, representing 38.7 MW and 141 MWh of capacity, as shown in the table below. Of the 133 installed storage projects, 130 are paired with solar projects, one is paired with solar and wind, and two are standalone storage projects, including one non-exporting battery and one 5 MW battery capable of exporting to the grid. There are 63 storage projects in the queue, including 58 projects paired with solar, one paired with a CTG, and four standalone storage projects.

Exhibit 2.20: Battery Storage

Category	Interconnected	In Queue

[18] Maine DOT EV Registrations
[19] US DOE Office of Energy Efficiency and Renewable Energy - Alternative Fuels Data Center
[20] Based on assumption that each level 2 port = 6.6kW and each DC fast port = 150 kW

Number of units	133	63
Capacity (MW)	38.7	35.4
Energy (MWh)	141	119

2.3.6. Transmission-connected Renewable Generation

In addition to the DER data included above, the following table shows the connected capacity and queued capacity of renewable generation at the transmission level.

Exhibit 2.21: Transmission-connected Renewable Generation

Technology	Capacity Connected (MW)	Capacity in Queue (MW)
Solar PV	262.4	747.8
Combined Solar + Storage	-	160.0
Standalone Storage	16.0	175.0
Hydro	27.6	-
Wind	15.3	77.1
Other	-	-
Total	**321.3**	**1,159.9**

03.
Forecasting and Scenario Development

This section describes the methodology and results of the demand forecasts, setting the foundation for understanding potential future load scenarios before addressing system needs and exploring possible solutions.

Key messages:

- The Company's load forecast is derived from ISO-NE's CELT (2024) forecast which considers underlying demand drivers including energy efficiency and solar PV.
- We're at an inflection point where demand is projected to increase over the next 10 years following a relatively flat load over the past decade driven primarily by heat pump and electric vehicle adoption.
- At a system level, CMP peak demand is forecast to grow by approximately 1 GW over the next decade, ~50% growth over current demand.
- Historically a summer peaking system, forecasts show the CMP system is expected to become winter peaking by 2027. A winter peaking system has different operational characteristics and needs than a summer peaking system, which is a significant consideration in overall system and resource planning and investments.

3. Forecasting and Scenario Development

3.1. Overview of Forecasts

3.1.1. What is load forecasting and why is it important?

Forecasting demand, also referred to as load, is a critical part of the Integrated Grid Planning process. Peak load refers to the period of time when demand is highest during the year and is a critical metric for planning electric network infrastructure, as the grid must have enough capacity to serve peak demand. Peak load forecasting is an important part of grid planning, as it enables the Company to assess the reliability of its electric infrastructure, helps identify system constraints, informs infrastructure investment decisions, and ensures that the grid remains reliable and resilient as Maine transitions toward its goal of 100% clean energy by 2040 and carbon neutrality by 2045.

Forecasting is especially important now because the drivers of load growth are changing. In the past, electricity demand was closely tied to economic growth. Today, electrification of heating and transportation, along with the rapid deployment of distributed energy resources (DERs) such as rooftop solar and battery storage, are reshaping the demand curve. These changes are decoupling load growth from traditional economic indicators and introducing new patterns of seasonal and hourly variability.

CMP's system experienced relatively flat demand growth for much of the 2010s. However, recent trends show a clear inflection point, with demand beginning to rise due to increased adoption of electric vehicles (EVs), heat pumps, and solar generation.

3.1.2. ISO-NE's CELT Forecast

ISO New England's Capacity, Energy, Loads, and Transmission (CELT) forecast provides an annual 10-year outlook of regional electricity demand, peak loads, generating capacity, and transmission needs. The forecast incorporates factors such as economic trends, historical and climate-adjusted weather data, state policies, and emerging technologies like distributed solar, electric vehicles, and heat pumps. It includes system-wide and zonal projections for energy consumption and seasonal peaks, along with assumptions about energy efficiency and behind-the-meter resources, such as those included in EMT's Triennial Plan VI and future plans. To account for weather variability, CELT provides both 50/50 forecasts, representing typical conditions, and 90/10 forecasts, which model extreme weather scenarios for reliability stress testing. While CELT uses "normal weather" assumptions and best-available data, uncertainties remain—particularly around electrification adoption, extreme weather events, and policy changes. ISO-NE updates the CELT report annually, typically in May, following stakeholder review and methodological refinements to improve accuracy and granularity. The CELT forecast is a foundational tool for regional system planning, resource adequacy assessments, and reliability studies, supporting both utility planning and regulatory decision-making.

3.2. Forecast Methodology

As required by the IGP Order, the forecasts used in the IGP process are derived from the 2024 ISO-New England CELT report. This regional forecast provides a consistent foundation for planning across New England. CMP disaggregated the CELT data to the distribution system level to reflect local conditions and infrastructure constraints.

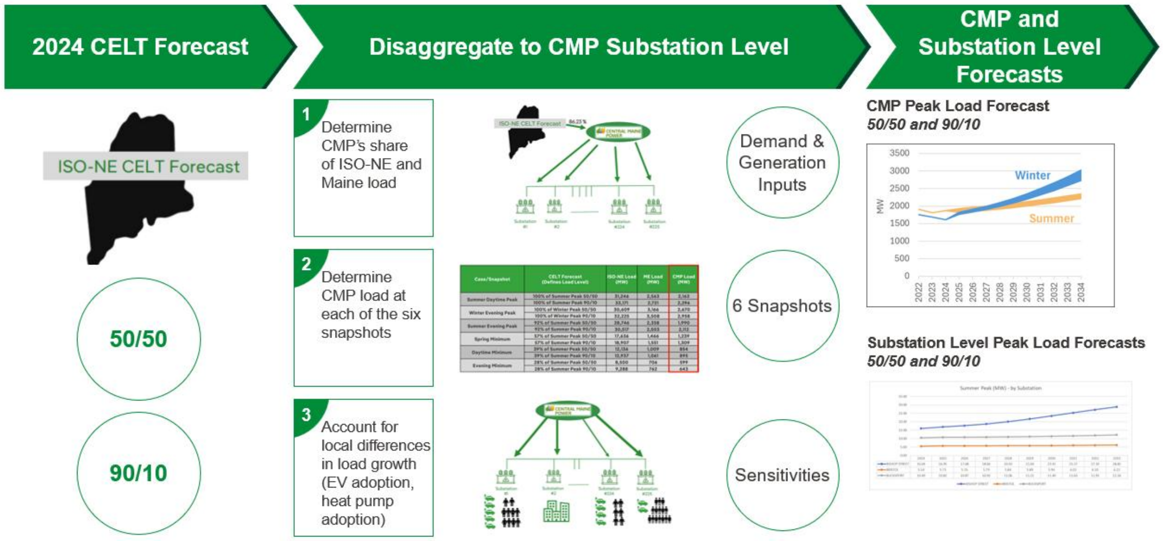
Two forecasts were developed as inputs to IGP planning, as required by the IGP Order:

- Baseline Forecast (50/50 Weather Condition): Represents typical weather conditions with a 50% probability of occurrence. This scenario serves as a reference case for evaluating system performance under expected conditions. This forecast is used as a proxy for a baseline forecast.
- High DER & Electrification Forecast (90/10 Weather Condition): Represents more extreme weather conditions with a 10% probability of occurrence. This forecast is used as a proxy for a High DER & Electrification Forecast, helping planners assess system reliability under higher peak outcomes more likely to occur in normal weather years with higher levels of DER adoption, electric vehicle (EV) penetration, and heating electrification.

Because the CELT forecast is developed at the transmission level, CMP created a disaggregation method to translate system-level projections to the distribution circuit level. CMP adjusted these projections to reflect local differences in load growth, including EV and heat pump adoption rates, population growth, and differences between industrial and residential load characteristics. First, the Company scaled down its own bottom-up substation level forecast to CMP's share of the ISO-NE CELT forecast to arrive at a substation level CELT forecast. Then each circuit was assigned a share of its substation's peak load using non-coincident peak data. These shares were applied to year-10 substation peak loads to derive circuit-level projections.

This approach provides system-level insights and highlights the collective needs of the network (or termed as 'coincident peak'). However, individual circuits often experience peak demand at different times and exhibit varying characteristics depending on the connected loads and distributed energy resources (DER) (or termed as 'non-coincident peak'). To account for these variations and individual needs, studies were conducted focusing on near-term system requirements. These studies help verify the differences across circuits and assess their potential impacts on overall system performance.

Exhibit 3.1: The IGP Forecasting Process



3.3. Six Snapshots

As further required by the IGP Order, the IGP forecasts also include six seasonal load snapshots to capture variability in demand and generation. These snapshots represent key moments of peak and minimum demand across different seasons and times of day. They are especially important in the context of intermittent solar generation, which varies significantly by time of day and season. By modeling both high and low load conditions, and periods of high and low solar output, CMP can better understand how the grid will perform under a range of realistic operating conditions.

This approach represents a limited time-series methodology—a practical alternative to full 8760-hour modeling. While CMP is working toward hourly forecasting across the full year, these six snapshots serve as critical proxies that capture the bookends of system behavior. They allow planners to identify potential reliability challenges, infrastructure constraints, and opportunities for non-wires alternatives without requiring the capabilities and computational intensity of fulltime-series simulations.

Exhibit 3.2: Six Seasonal Load Snapshots

Case/Snapshot	CELT Forecast (Defines Load Level)	ISO-NE Load (MW)	ME Load (MW)	CMP Load (MW)
Summer Daytime Peak	100% of Summer Peak 50/50	31,246	2,563	2,163
	100% of Summer Peak 90/10	33,171	2,721	2,296
Winter Evening Peak	100% of Winter Peak 50/50	30,609	3,166	2,670
	100% of Winter Peak 90/10	32,225	3,508	2,958
Summer Evening Peak	92% of Summer Peak 50/50	28,746	2,358	1,990
	92% of Summer Peak 90/10	30,517	2,503	2,112
Spring Minimum	57% of Summer Peak 50/50	17,636	1,466	1,239
	57% of Summer Peak 90/10	18,907	1,551	1,309
Daytime Minimum	39% of Summer Peak 50/50	12,136	1,009	854
	39% of Summer Peak 90/10	12,937	1,061	895
Evening Minimum	28% of Summer Peak 50/50	8,500	706	599
	28% of Summer Peak 90/10	9,288	762	643

*2034 numbers

This table illustrates the six key seasonal load conditions modeled under both the 50/50 and 90/10 weather year scenarios, capturing peak and minimum load periods across summer, winter, and spring.

3.4. Modeling Inputs

3.4.1. Generation

Generation inputs for the planning models estimate how much generation will be available, identify the sources, and specify when that generation will occur over the course of the day and year. CMP evaluated key variable resources in its service territory such as solar, battery energy storage, hydro and wind across the six snapshots representing different seasonal and load conditions. Assumptions for solar and battery energy storage were based on the ISO-NE Technical Planning Guide[21] and hydro and wind input assumptions were determined in MPUC Docket No. 2011-00494. These inputs form the foundation for modeling resource adequacy and system reliability under varying conditions. CMP understands that the CELT forecast includes baseline energy supply data and assessments, including but not limited to planned generation retirements; new generation that is planned or needed, including generation of electricity from renewable sources; and energy storage installations.[22]

As shown below, each of the different snapshots has a different generation profile. For example, while solar will not be available in the summer evening peak, battery storage could be dispatched and run-of-river hydro and wind can be available.

[21] ISO-NE Transmission Planning Technical Guide. March 21, 2024.
[22] 35-A MRSA 3147(4)(D)(2).

Exhibit 3.3: Impacts of Variable Generation on Six Seasonal Load Snapshots[23]

Case / Snapshot	Solar (%)	Battery Energy Storage Systems (BESS)	Run-of-River (ROR) Hydro	Wind (%)
Summer Evening Peak	0	Discharging MWh/6	Safe Harbor summer peak	10
Summer Daytime Peak	40	Offline	Safe Harbor summer peak	10
Winter Evening Peak	0	Discharging MWh/6	Safe Harbor winter peak	20
Daytime Minimum	90	Charging	Safe Harbor off-peak	20
Evening Minimum	0	Offline	Safe Harbor off-peak	20
Spring Minimum	90	Discharging MWh/6	Safe Harbor off-peak	20

The geographic distribution of DERs was also utilized in the study cases using CMPs internal Customer Net Energy Billing Agreement (CNEBA) queue to reflect the sensitivities associated with DER locations. The capacity of each individual DER from the CNEBA queue was proportionally scaled in accordance with CMP's share of the Maine load forecast:

ISO-NE 2034 Maine DER forecast (from 2024 CELT) = 1,854 MW

CMP percentage share (from 2024 CELT) = 86.23%

CMP DER obligation (based on 2024 CELT) = 1,854 MW * 0.8623 = 1,599 MW

The CMP DER obligation was then scaled based on the scenario under study. For example, the Summer Daytime Peak scenario requires a 40% PV dispatch. So, for the Summer Daytime Peak scenario, the solar DER was then scaled to 40% of 1,599 MW or 639 MW to reflect the 2024 CELT forecast.

3.4.2. Infrastructure

The planning models also incorporate a set of defined infrastructure assumptions to ensure that the system is accurately reflected over the next decade. These inputs provide the foundation for evaluating future needs and identifying potential solutions.

For transmission, the modeling incorporated only ISO New England–approved projects, consistent with the ISO Transmission Planning Technical Guide. These projects are already embedded in ISO's planning models and represent reinforcements assumed to be completed and in service by 2034. The approved and planned transmission upgrades were drawn from the ISO Base Case Library and Base Case Database (BCDB) dated August 28, 2024. The specific BCDB version used—2024TPBCL_2024-08-28—along with a detailed list of included projects

[23] Safe harbor values are adopted from MPUC docket 2011-494 and determined based on the latest three-year historical average output during two seasonal conditions to use in CMP's local area studies to address long term reliability needs.

is provided in Appendix D. This approach ensures alignment with regional planning standards and reflects the most current transmission planning assumptions.

For distribution, the modeling was based on the existing network configuration without incorporating future projects. This decision allows the IGP to focus on identifying needs under current conditions and then evaluate how proposed solutions could address those needs. While future distribution upgrades were not modeled directly, the analysis compared the effectiveness of candidate solutions against the needs identified in the IGP, ensuring that recommendations remain practical and targeted. Although future projects were not directly incorporated in the modeling, projects that are certain to come online during the planning period were incorporated into the needs and solutions phases, to confirm that they address rising needs and can be identified in the solutions phase.

3.4.3. Transmission Inputs

CMP's transmission modelling is based on the network model published in 2024 ISO-NE Steady-State Transmission Planning Base Case Library (TPBCL). CMP utilized the 12 core scenarios and further developed 6 additional transmission planning scenarios based on system interface stresses using base cases published in the 2024 ISO-NE Steady-State Transmission Planning Base Case Library, released in April 2025.

These 18 total cases incorporate the 2024 ISO-NE CELT forecast, which includes projections for renewable penetration and geographic distribution. The transmission assessment was performed in accordance with the following procedures and requirements:

- ISO New England Transmission Planning Technical Guide Revision 8.2
- ISO New England Planning Procedure 5-3 "Guidelines for Conducting and Evaluating Proposed Plan Application Analysis"
- NERC TPL-001-5.1 "Transmission System Planning Performance Requirements"
- NPCC Directory 1 "Design and Operation of the Bulk Power System"
- AVANGRID Technical Manual TM 1.2.00 "Electric Transmission Planning Manual - Criteria & Processes"

In the table below, "D1" represents a high north-to-south flow of generation from Maine to the rest of New England, and "D2" represents a low north-to-south flow of generation from Maine. The "D2" scenario was run on the 90/10 forecast only to avoid the redundancy that would occur between a "D2" scenario on the 50/50 forecast and a "D1" scenario on the 90/10 forecast. These two dispatch scenarios are:

- Dispatch D1 (High North to South Transfers):
  - High Surowiec – South with Buxton STATCOMs in service
  - High Maine – New Hampshire export
  - High New Brunswick – New England export

– NECEC online

- Dispatch D2 (Low North to South Transfers):
  – Low Maine – New Hampshire export
  – Low New Brunswick – New England export
  – NECEC offline

The high north to south transfer scenario (D1) models a 1,000 MW import from New Brunswick into as well as a 1,200 MW import from Quebec. These imports combined with higher levels of generation within Maine results in an export from Maine to New Hampshire of around 2,200 MW. The low north to south transfer scenario (D2) models no imports from New Brunswick or Quebec and utilizes local Maine generation to serve the load. This results in a system condition where Maine has low or no export to New Hampshire. These generation dispatch scenarios establish two bookends of operating conditions that the Maine transmission system experiences.

Exhibit 3.4: 18 Modeled Cases for Transmission Studies

Study Case Load scenarios at 50/50 and 90/10

Scenario (Defines Load Level)	Case/Snapshot	Net Load (% of Initial Scenario Load)	ISONE 2034 Load and Losses (MW)	Generation Dispatch
Baseline	Summer Evening Peak	92% of Summer Daytime Peak 50/50	28,372	D1
High Penetration		92% of Summer Daytime Peak 90/10	30,182	D1, D2
Baseline	Summer Daytime Peak	100% of Summer Daytime Peak 50/50	30,839	D1
High Penetration		100% of Summer Daytime Peak 90/10	32,807	D1, D2
Baseline	Winter Evening Peak	100% of Winter Evening Peak 50/50	30,186	D1
High Penetration		100% of Winter Evening Peak 90/10	31,838	D1, D2
Baseline	Daytime Minimum	39% of Summer Daytime Peak 50/50	12,027	D1
High Penetration		39% of Summer Daytime Peak 90/10	12,795	D1, D2
Baseline	Evening Minimum	28% of Summer Daytime Peak 50/50	8,635	D1
High Penetration		28% of Summer Daytime Peak 90/10	9,186	D1, D2
Baseline	Spring Minimum	57% of Summer Daytime Peak 50/50	17,578	D1
High Penetration		57% of Summer Daytime Peak 90/10	18,700	D1, D2

3.4.4. Contingencies

CMP conducted a contingency analysis to evaluate the entire CMP high voltage and extra high voltage transmission system to assess reliability or operational impacts based on the ISO-NE forecast inputs. In transmission planning, a contingency refers to when a component of the system is offline, which might occur due to an outage or scheduled maintenance. The transmission study focused on steady state thermal and voltage analysis by evaluating reliability under the following conditions:

- All-lines-in service (N-0 Analysis) for the 18 load level conditions
- N-1 Analysis: Contingency analysis of single and multiple element design contingencies at the 345 kV, 115 kV, and 34.5kV voltage levels for the same scenarios as the N-0 analysis

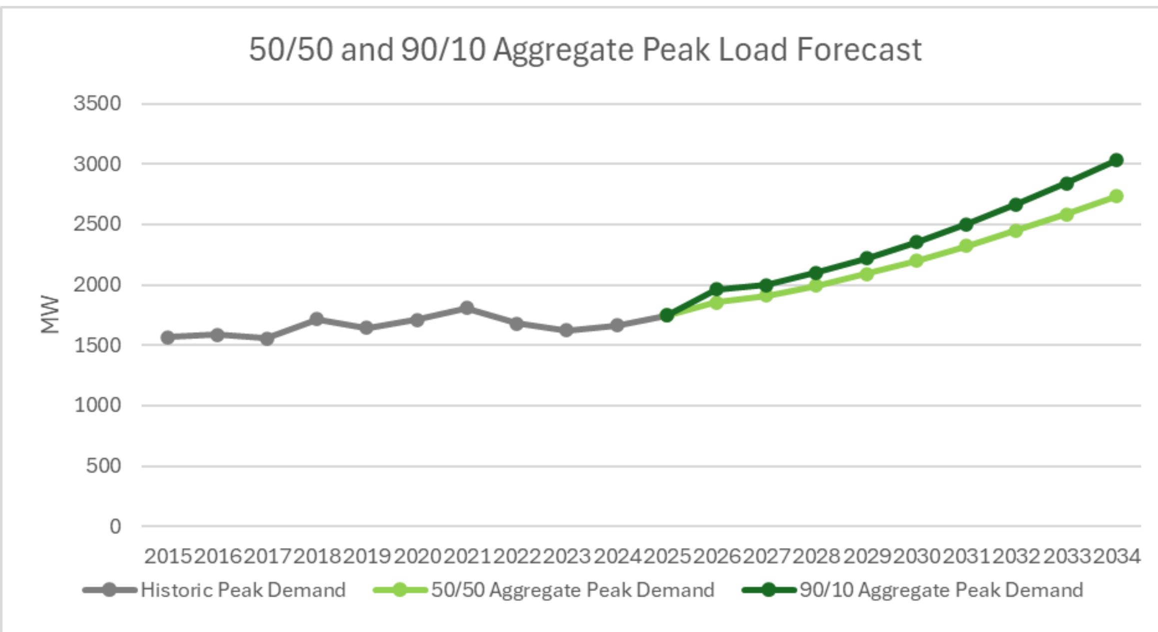
- N-1-1 Analysis: Contingency analysis of single and multiple element design contingencies at the 345 kV and 115 kV levels with initial outage of a 345 kV or 115 kV element for the same scenarios as the N-0 and N-1 analyses
- Scheduled Maintenance Analysis: Planned outage for maintenance followed by an unplanned single element on the system for shoulder load level only.

How contingencies were incorporated into the grid plan is discussed further in Section 4.2.

3.5. Demand Forecast Findings

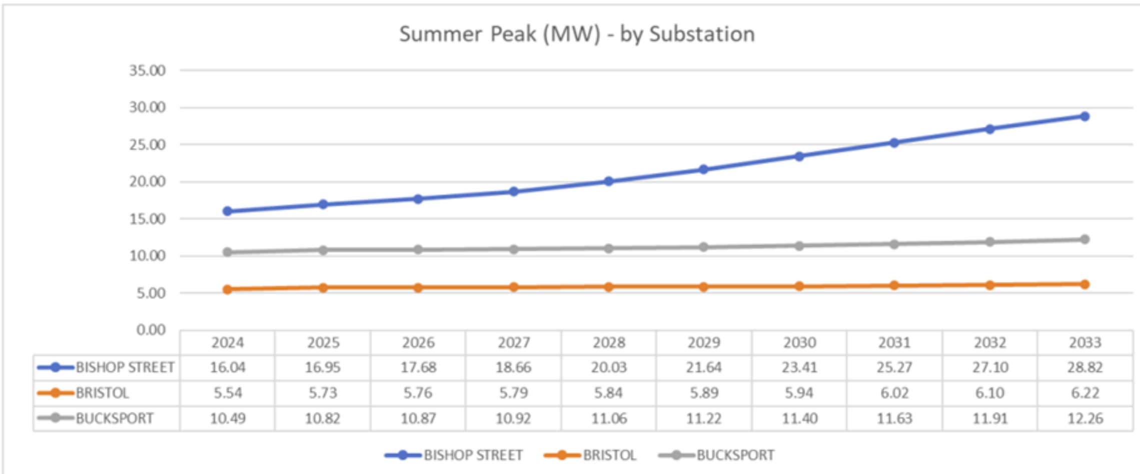
The CELT forecast, disaggregated to CMP's service area, reveals a significant shift in load patterns over the next decade. Following a period of relatively flat demand growth over the past decade, the system is at an inflection point where demand is expected to increase substantially over the next 10 years, driven by electrification of heating and transportation. At a system level, CMP peak demand is forecast to grow by approximately 1 GW over the next decade, ~50% growth over current demand.

Exhibit 3.5: CMP 50/50 and 90/10 Aggregate Peak Load Forecast



Summer peak load growth varies widely across the system, with some substations showing no growth and others projecting increases of up to 150%, particularly in urban areas. Winter peak load is forecasted to grow more significantly, with increases of up to 370%. Nearly half of CMP's substations are projected to more than double their winter peak load, with rural areas experiencing the highest increases due to heat pump adoption as many customers continue to transition off of oil and propane heating. In the exhibit below, the Portland-area Bishop Street substation shows higher growth than the more rural Bristol and Bucksport substations.

Exhibit 3.6: Selected substation level forecasts below show higher growth areas compared to lower growth areas



CMP anticipates over 1,500 MW of distributed solar generation on its system by 2033, up from approximately 939 MW currently in service. In some rural areas, DER output may exceed local demand, creating opportunities for grid optimization and non-wires alternatives.

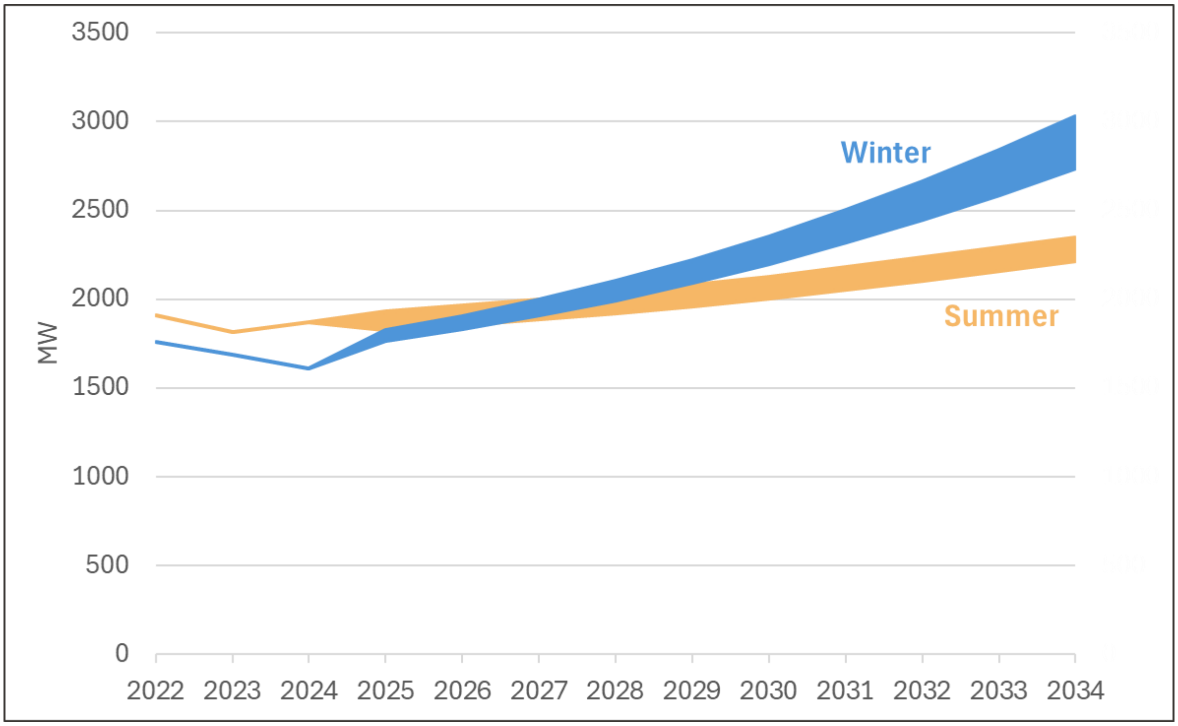
Forecast outcomes are influenced by several factors. Higher peak demand scenarios may result from high adoption of EVs and heat pumps and limited uptake of energy efficiency, demand response programs, and load management technologies. Conversely, lower peak demand scenarios could occur if energy efficiency and demand response programs are widely adopted, flexible devices are deployed, and demand optimization strategies are effectively implemented.

3.6. The Shift to a Winter Peaking System

One of the most significant changes in CMP's load profile is the transition from a summer-peaking system to a winter-peaking system, which is forecasted to occur by around 2027. This shift is driven primarily by the widespread adoption of electric heat pumps, which increase electricity demand during cold months. According to the 2024 CELT Report, Maine is forecasted to see a 10x increase in electric heating demand driven by heat pump adoption in the next ten years.

This transition has major implications for grid planning. Winter peaks tend to be longer and more sustained than summer peaks, placing different demands on infrastructure. At the same time, solar generation is significantly lower in winter, reducing the availability of local generation and increasing reliance on grid-supplied power. Reliability planning must now account for cold-weather contingencies, voltage stability, and thermal overload risks during winter evenings, conditions that were previously less critical.

Exhibit 3.7 CMP's peak load is forecasted to shift to the winter in the late 2020s

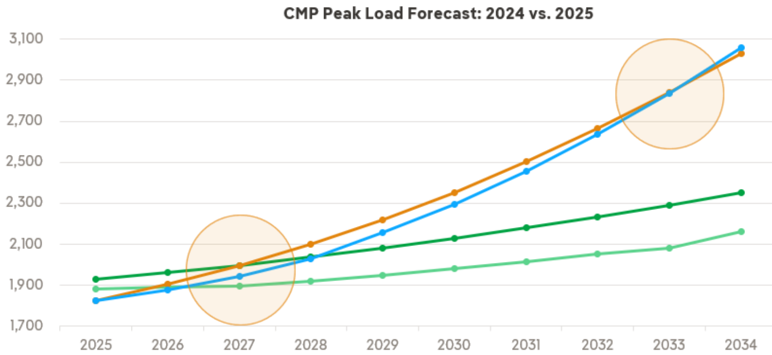


3.7. 2024 CELT Forecast and 2025 CELT Forecast

In May 2025, approximately ten months after issuance of the IGP Order, ISO-NE published its updated 2025 CELT forecast. While some stakeholders have questioned CMP's reliance on the 2024 CELT forecast for this Grid Plan, changing forecasts mid-process is neither practicable nor permissible, as the IGP Order explicitly mandates use of the 2024 report.

That said, CMP's review of the 2025 forecast shows that it generally reflects a more conservative near-term outlook for load growth, particularly during summer months. Both forecasts, however, project steady long-term growth and indicate that CMP will transition to a winter-peaking system by 2027. Although summer peak projections are consistently lower in the 2025 report, winter peak estimates converge by 2033, and the 2025 CELT forecast actually anticipates a slightly higher winter peak in 2034.

Exhibit 3.8: Comparison of CELT Forecasts



Trend:

- Summer 90/10: Consistent increase in the difference between reports
- Winter 90/10: Fluctuating differences, turning positive in 2033

Overall impact of updated CELT report

CMP Winter Peaking:

- CMP could switch to winter peaking by 2027 (both CELT reports)

Peak Changes:

- 2025 vs. 2024: CMP peak 3% lower
- Reduction of 49 MW (summer 90/10)
- Difference in forecasted peak diminishes over time

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MW Values 2024 Report										
Summer 90/10	1,932	1,963	1,997	2,036	2,080	2,128	2,180	2,234	2,291	2,350
Winter 90/10	1,826	1,906	1,998	2,102	2,220	2,352	2,501	2,664	2,839	3,029
MW Values 2025 Report										
Summer 90/10	1,883	1,890	1,898	1,922	1,950	1,982	2,015	2,053	2,081	2,162
Winter 90/10	1,824	1,878	1,942	2,031	2,155	2,295	2,456	2,637	2,837	3,056

3.8. Milestone 1 Stakeholder Feedback

Stakeholders generally supported CMP's approach to developing inputs for the grid planning models but offered several comments and recommendations detailed further below.

Load Forecasting and Disaggregation

- Stakeholders emphasized the importance of clearly explaining the disaggregation approach for ISO-NE's CELT forecast. (CMP revised the Milestone 1 presentation and has included a more detailed analysis in this report.)
- Questions were raised about how theoretical modeling (CELT) connects to actual electrification trends. (CMP has explained its "bottom-up" approach to applying the CELT forecast, and the differences between coincident and non-coincident peak above in this Section 3)
- CMP was urged to gauge attrition in the 2024 interconnection queue and reflect that in assumptions. (CMP has not incorporated any attrition assumptions, since queued DER does not exceed CELT forecasts, and the IGP Order requires use of the CELT forecast.)

Modeling Approach

- Environmental NGOs asked what models CMP uses and how they relate to existing planning processes. (CMP uses the same core models, but area studies provide further depth as explained in Sections 4.1 and 4.2.)

Scenario Development and Snapshots

- Stakeholders supported eliminating some low-value snapshots to streamline analysis.

- Questions about why only two 2040 models were included and how these relate to Maine's Pathways to 2040 study. (The 2024 CELT forecast provides a path toward Maine's 2040 goals.)
- Suggestions to weave in a time-series roadmap for future planning and to consider ANM (Active Network Management) grant screening in near-term circuit classification. (Time-series planning is discussed in Sections 4.5 and 6; the DOER federal FIRM grant involving ANM was rescinded.)

Additional Public Meeting

During the January 27, 2025 Milestone 1 public meeting the following feedback was received:

- Stakeholders sought clarity on contingency modeling, offshore wind assumptions, and battery storage treatment. (CMP confirmed that approved and queued projects will inform generation modeling and that microgrids and advanced technologies will be considered later in the process.)
- Questions about transmission and distribution modeling highlighted the potential for enabling technologies and time-series analysis in future planning. (Enabling technologies and time-series planning are incorporated into the IGP in Sections 4 and 6.)
- Interest in demand-side measures such as time-of-use rates and hosting capacity maps for municipal planning was noted. (Hosting capacity maps are discussed in Section 6.3.1.)

04.
System Modeling and Needs Identification

This section provides an overview of the methodology and results from the system modeling and assessment to identify system needs using the forecast inputs described in Chapter 3.

Key Takeaways

- Over the next 10 years, CMP expects significant load growth driven by the electrification of transportation and heating and continued growth in DERs such as solar and storage to meet Maine's ambitious climate goals.
- This growth is projected to exceed the capacity of the current network and create grid constraints. If unaddressed, these constraints could be bottlenecked to meeting Maine's climate goals.
- CMP conducted system modeling using 12 forecast scenarios and observed significant thermal overloads in both the winter and summer, including 115 distribution substations and 123 circuits by 2034.
- The majority of system needs are during peak load conditions in heavily populated areas of southern Maine.
- There are fewer loading concerns in more rural areas of the state, however, high penetration of distributed generation results in violations in the reverse direction when solar output exceeds the capacity of the circuit.

4. System Modeling and Needs Identification

The second phase of the grid planning process, as required by the IGP Order, was to apply the forecasts and models to the system to determine the scope of potential needs over the 10-year grid planning period. As a result of that analysis, it is clear that a wide range of system needs will need to be addressed to accommodate the forecasted load and DER growth described in Section 3, driven by electrification of heating and transportation and continued growth in renewables to meet Maine's climate goals. The demand growth projected in those forecasts is expected to exceed the capacity of the current network and create grid constraints, which if unaddressed will result in unsafe, unreliable power for customers.

4.1. Distribution Planning Criteria and Current Practices for Needs Identification

CMP's distribution planning process employs a comprehensive approach to ensure system reliability under a range of plausible scenarios. The objective is to deliver safe and reliable service in compliance with MPUC rules, legislative requirements, and service quality standards—including voltage variation limits and customer service metrics—as reported in CMP's quarterly performance reports.

4.1.1. Current System Planning Approach

CMP conducts annual monitoring and analysis to identify potential system concerns. Detailed distribution area studies are scheduled for substations based on condition-based triggers, including:

- **Thermal Capacity Concerns (N-0):** Identified through annual peak loading analysis when thermal overload risks are detected.
- **Voltage and Power Quality Concerns:** Initiated by customer complaints or observed voltage deviations. Service voltage must remain within ±5% of nominal under normal conditions, with fluctuations limited to ±3%.
- **Reliability and Resiliency Performance Issues:** Emerging trends from annual reliability and resiliency reviews that indicate declining performance.
- **Real-Time Operational Concerns:** Feedback from system operators regarding thermal, voltage, or N-1 backup supply issues.

In addition to these triggers, CMP performs annual assessments covering peak loading, reliability and resiliency, distribution automation, system hardening, and load/generation interconnection studies.

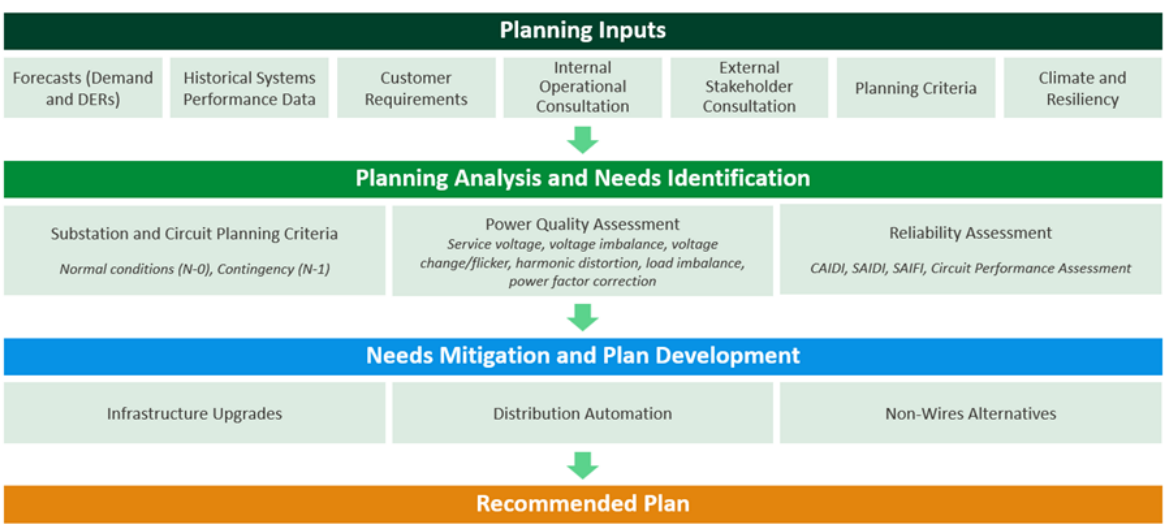
If these analyses indicate the need for further investigation, CMP initiates an area study, which typically includes:

- Thermal Capacity Analysis (N-0)
- Thermal Emergency/Contingency Analysis (N-1)
- Steady-State Voltage Analysis
- Reliability and Resiliency Performance Review
- Circuit Customer Count
- Power Factor Analysis
- Distribution Automation Assessment
- Load Balance Analysis
- Common Voltage Analysis
- Substation Asset Condition Screening

Area studies represent CMP's most comprehensive evaluation of distribution system needs and solutions. These studies typically require 3–4 months per area and assess short-, mid-, and long-term performance for each substation and its associated circuits. They incorporate multiple scenarios and system conditions, including future load forecasts, seasonal variations (summer and winter), and anticipated distributed energy resource (DER) integration.

CMP's Distribution Planning Criteria includes equipment rating methodology and specific criteria utilized for each of these analyses.

Exhibit 4.1: Distribution Planning Process

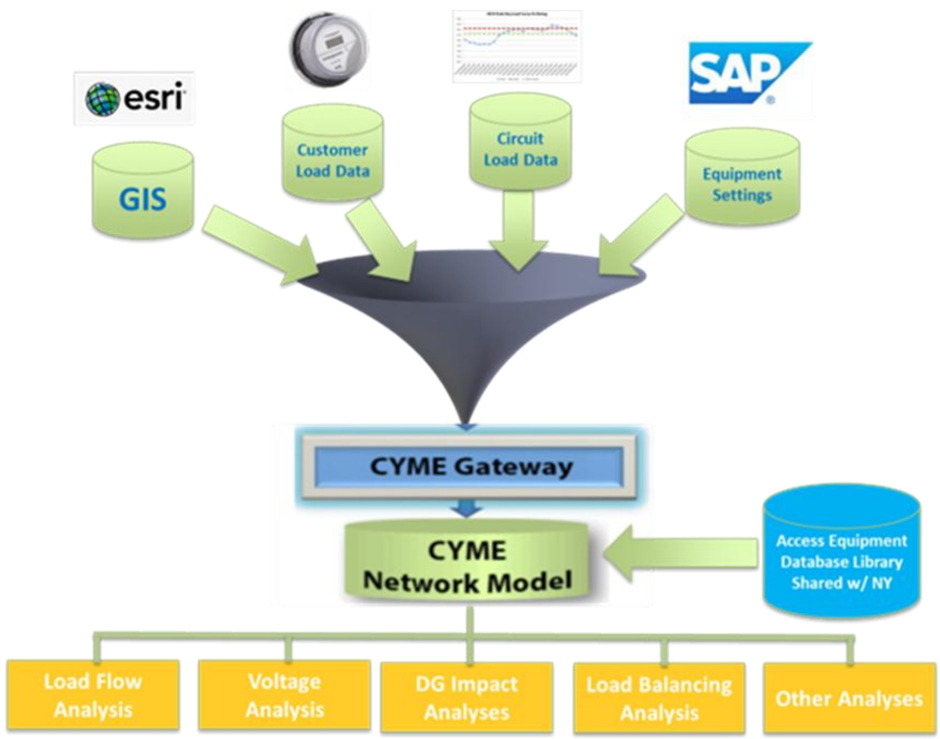


4.1.2. Current System Planning Tools

CMP has a variety of tools to make data driven decisions related to needs identification, including CYME software, as well as a reliability calculator and benefit cost analysis tool.

CMP uses CYME Power System Analysis software ("CYMDIST"), a Power Engineering analysis tool used to simulate the distribution system and to assess its performance for planning, operational, and contingency purposes. The CYMDIST application is used to perform Reliability Assessment, Network Optimization, Coordination of Protection Devices, and to analyze and assess the impact of DERs on the distribution system, commonly referred to as Distributed Generation (DG) as illustrated in Exhibit 4.2. These analyses enable the CMP Engineering Department to develop system expansion plans that help to provide safe and reliable service to its customers at fair and reasonable costs.

Exhibit 4.2: Distribution Planning Software



To estimate the SAIFI improvement from the proposed project, CMP has developed a reliability calculator that takes inputs related to grid interventions and produces both reliability related outputs and projected benefit values based on the Department of Energy's Interruption Cost Estimate (ICE) calculator.

To estimate the benefit of a proposed project relative to cost, CMP has also developed a benefit cost analysis tool that uses project inputs and factors, including Reliability Improvement, Resiliency Improvement, Operational Efficiency, Capacity Benefits and Risk of Non-Supplied Energy (Loss of Load) to provide benefit to cost values for certain investments.

4.1.3. Alignment with Minimum Service Quality Standards

The distribution planning criteria is aligned with minimum service quality standards (MPUC Chapter 320 section 4) including: system/service voltage limits with 5% of nominal volage as prescribed by ANSI C84.1, maintaining harmonics levels within 5% total harmonic distortion, in line with IEEE 519, and maintaining frequency and magnitude of flicker events in accordance with IEEE 1453.

4.1.4. Alignment with Other Service Quality Targets

The distribution planning criteria specifies reliability analysis and criteria. Reliability analysis focuses on 3-year historical outage data and SAIFI metrics for each circuit. This outage data is used to propose projects to improve system reliability, such as adding protective devices, hardening sections of circuit prone to tree and weather-related outages, or adding backup circuit ties. Reliability improvement for proposed projects is calculated using CMP's reliability calculator to compare results. This analysis and the reliability-driven projects that are proposed from the analysis drive system reliability to meet chapter 320 benchmarks and yearly reliability SQI metrics established by the PUC.

4.2. IGP Distribution and Transmission System Needs Assessment Methodology

The Integrated Grid Plan provides a full system-wide view of projected needs driven by the demand and DER growth forecasted over the next ten years, providing a view of what it would take to meet Maine's climate goals. The IGP study complements the existing detailed planning studies by taking a long-term view and providing a high-level picture of emerging needs across the system driven by rising demand and DERs. Because this analysis takes a higher-level approach and is less detailed than area studies, it is not intended as a rate proposal.

As described in Section 3, CMP developed six seasonal load snapshots to capture variability in demand and generation (summer daytime peak, winter evening peak, summer evening peak, spring minimum, daytime minimum, and evening minimum). These snapshots represent key moments of peak and minimum demand across different seasons and times of day, and to represent the variability of intermittent DER resources like solar generation, which varies significantly by time of day and season. By modeling both high and low load conditions, and periods of high and low intermittent DER output, CMP can better understand how the grid is expected to perform under a range of operating conditions and develop strategies for addressing variations in generation. The six seasonal load snapshots developed for both the 50/50 and 90/10 forecasts resulted in 12 scenarios for evaluation on the distribution system.

When assessing needs, CMP focused on thermal and voltage needs because these grid impacts typically drive the most investment requirements. Thermal overloads are caused by loads exceeding the limits of equipment to serve the load, which generates excess heat and can cause equipment failure. Voltage violations occur as the equipment approaches its limit, which reduces voltage on the system, which then impacts power quality. In the extreme, voltage can be reduced or increased beyond safe operating parameters of equipment, causing damage to the system and/or customer equipment. Mitigation of these violations can involve expensive equipment with long lead times and labor-intensive construction. On the transmission system, the longer distances reduce the likelihood that addressing thermal overloads will also solve voltage violations, so analysis of both thermal and voltage has been conducted on that system.

At the advice of stakeholders during Milestone 2, CMP has also differentiated DER-driven versus non- DER-driven needs. This allows for an improved understanding of the scope of these non-DER-driven needs without necessarily included them in solutions development, which reflects the current policy of generally assigning responsibility for upgrades necessary for DER interconnection to the DER customer.

The needs assessment in this Section reflects the efficiency measures included in the 2024 CELT forecast, such as those included in EMT's Triennial Plan VI and future plans. CMP recognizes that future triennial plans should be carefully reviewed by all stakeholders for potential impacts of EMT programs that could reduce demand and affect potential needs.

4.2.1. Distribution System Needs Assessment Methodology

For the purposes of this IGP, which undertakes a system-wide needs assessment in contrast to the annual monitoring and analysis, with subsequent detailed area studies for only portions of the system, the distribution needs assessment included evaluation at the substation transformer level, circuit level, and sub-circuit level. This staged methodology provides a structured and scalable way to assess system constraints under tested scenarios without conducting full area studies, which would require an enormous dedication of time and resources exceeding the scope of the IGP statute and Order. The IGP needs assessment began with substation transformer and circuit level reviews, where initial studies were conducted across all 493 circuits under 12 scenarios. This broad analysis identified potential stress points and informed the selection of 70 representative sample circuits for detailed modeling.

Those 70 sample circuits underwent detailed CYME modeling at the sub-circuit level, focusing on core equipment such as transformers and conductors. This granular analysis revealed:

- Likely lengths and severity of circuit overloading.
- Specific constraint elements
- Efficacy of various options, such as the optimized location and/or size of the BESS

The insights from these detailed studies were then proportionally scaled up to estimate the magnitude of system-wide needs—including reinforcement requirements, operational adjustments, and investment priorities.

Substation Transformer Level Analysis
A substation transformer is defined as a transformer inside a substation that serves distribution circuits. Substation transformers are typically the single most costly piece of equipment on the distribution system, and lead times for new substation transformers can exceed two years. Therefore, it is imperative that utilities identify transformer needs and solutions in a proactive manner. CMP applied the 12 forecast scenarios to all 250 substation transformers and

compared the substation-level forecasts to the transformer's rated capacity. This process identified transformers that might be projected to face thermal overloads over the forecast period.

Circuit Level Analysis
At the circuit level, CMP applied the forecast to all 493 distribution circuits using the 12 forecast scenarios. The forecasted load was then compared to the limiting thermal element at the substation exit, which in practice represents the largest conductor or cable, or substation voltage regulators. This process identified thermal overloads at the beginning (or "head end") of distribution circuits. Based on the CYME modeling of the 70 representative circuits, we feel confident that identifying thermal overloads at this level of detail is sufficient to capture needs; addressing the thermal overload also addresses the voltage violation. In CYME modeling of the 70 circuits, focusing on solving the thermal overload need significantly improves the voltage on the circuit.

Sub-circuit Level Analysis
At the sub-circuit level, CMP selected 70 circuits for detailed CYME modeling of the entire circuit across the 12 forecast scenarios. The 70 were chosen to represent a wide range of circuit-level loading, from roughly three quarters of rated loading up to twice that level, so that lessons learned from these feeders can be reasonably applied to feeders elsewhere. This deeper modeling allocates forecasted load along the feeder and evaluates thermal and voltage performance all the way to the ends of laterals and through regulator locations. It is the best way to see where issues will actually show up for customers. After completing detailed sub-circuit studies on 70 feeders, CMP extrapolated the results to all circuits across the system that are expected to have insufficient headroom under forecasted conditions. The circuit-level loading for the 70 circuits studied was as indicated below:

- 75%–90% projected load level: 15 circuits
- 90%–110% projected load level: 13 circuits
- 110%–150% projected load level: 22 circuits
- 150%–200% projected load level: 12 circuits
- DER reverse power flow (overloading): 8 circuits

This deeper modeling allocates forecasted load along the feeder and evaluates thermal and voltage performance all the way to the ends of laterals and through regulator locations. It is the best way to see where issues will actually show up for customers. After completing detailed sub-circuit studies on 70 feeders, CMP extrapolated the results to all circuits across the system that are expected to have insufficient headroom under forecasted conditions.

The 15 circuits in the 75%–90% circuit loading category were included in the analysis to determine whether overloaded equipment was present. While this review was valuable to identify that solutions are in fact often needed even with this relatively low level of loading, no solutions for these circuits were presented in the scorecard because the corrective actions identified were routine and low complexity, such as replacing small transformers, upgrading reclosers, or changing fuses. Because these do not represent significant system challenges or innovative solutions, these circuits were excluded from the scorecard to maintain focus on higher-impact issues.

4.2.2. Transmission Needs Assessment Methodology

The transmission analysis that accompanies this plan applies the same principles to the high voltage system. Using the 18 scenarios described in Section 4.4.3, CMP conducted a contingency analysis to evaluate the entire CMP high voltage and extra high voltage transmission system to assess reliability or operational impacts based on the ISO-NE forecast inputs. The transmission study focused on steady state thermal and voltage analysis by evaluating reliability under the following conditions:

- N-0 Analysis: All-lines-in service () for the 18 load level conditions
- N-1 Analysis: Contingency analysis of single and multiple element design contingencies at the 345 kV, 115 kV, and 34.5kV voltage levels for the same scenarios as the N-0 analysis
- N-1-1 Analysis: Contingency analysis of single and multiple element design contingencies at the 345 kV and 115 kV levels with initial outage of a 345 kV or 115 kV element for the same scenarios as the N-0 and N-1 analyses
- Scheduled Maintenance Analysis: Planned outage for maintenance followed by an unplanned single element on the system for shoulder load level only.

The transmission assessment was performed in accordance with the following procedures and requirements which are required to be utilized for the 115kv and above system, and the safe harbor criteria[24] for below 115kv:

- ISO New England Transmission Planning Technical Guide Revision 8.2
- ISO New England Planning Procedure 5-3 “Guidelines for Conducting and Evaluating Proposed Plan Application Analysis”
- NERC TPL-001-5.1 “Transmission System Planning Performance Requirements”
- NPCC Directory 1 “Design and Operation of the Bulk Power System”
- AVANGRID Technical Manual TM 1.2.00 “Electric Transmission Planning Manual - Criteria & Processes”

4.3. Summary of Distribution and Transmission Needs

The process of system modeling using forecasted demand and DERs to simulate future conditions provides a comprehensive view of where and when grid upgrades or modifications might be needed. The IGP needs assessment identified significant thermal overloads and voltage violations at the distribution and transmission level, driven both by load and DERs. The needs summary in Exhibit 4.3 below provides an overview of the violations expected to occur if

[24] Safe harbor values are adopted from MPUC docket 2011-494 and determined based on the latest three-year historical average output during two seasonal conditions to use in CMP's local area studies to address long term reliability needs.

demand and DER growth is not proactively addressed. It also shows the percentage of total assets impacted, putting into perspective the level of grid constraints expected.

Exhibit 4.3: Transmission and Distribution Needs Summary

Transmission and Distribution (T&D) Needs Summary

Thermal / Voltage	2034 Violations	2034 % of Total
Distribution Substation Transformer	115	46%
Distribution Circuit	123	25%
Transmission Transformer	34	28%
Transmission Line	107	31%
Transmission Voltage	76	15%
DER Interconnection Driven	**Violations**	
Distribution	39	
Transmission	221	
Total Capacity-Driven Needs	**715**	

4.3.1. Distribution Needs

The IGP distribution system analysis identified loading concerns emerging at 115 substation transformers and 123 circuits where the load is forecast to exceed normal equipment ratings by 2034. This represents 46% of all substation transformers and 25% of all circuits. The needs summary in Exhibit 4.4 below provides an overview of violations identified in three of the snapshots that drive most of the overloads, winter peak, summer peak and daytime minimum load (when DER-driven reverse power flows tend to drive needs), as well as a view of the number of projected thermal overloads on unique assets.

Exhibit 4.4: Distribution Needs Summary[25]

Distribution Needs Summary

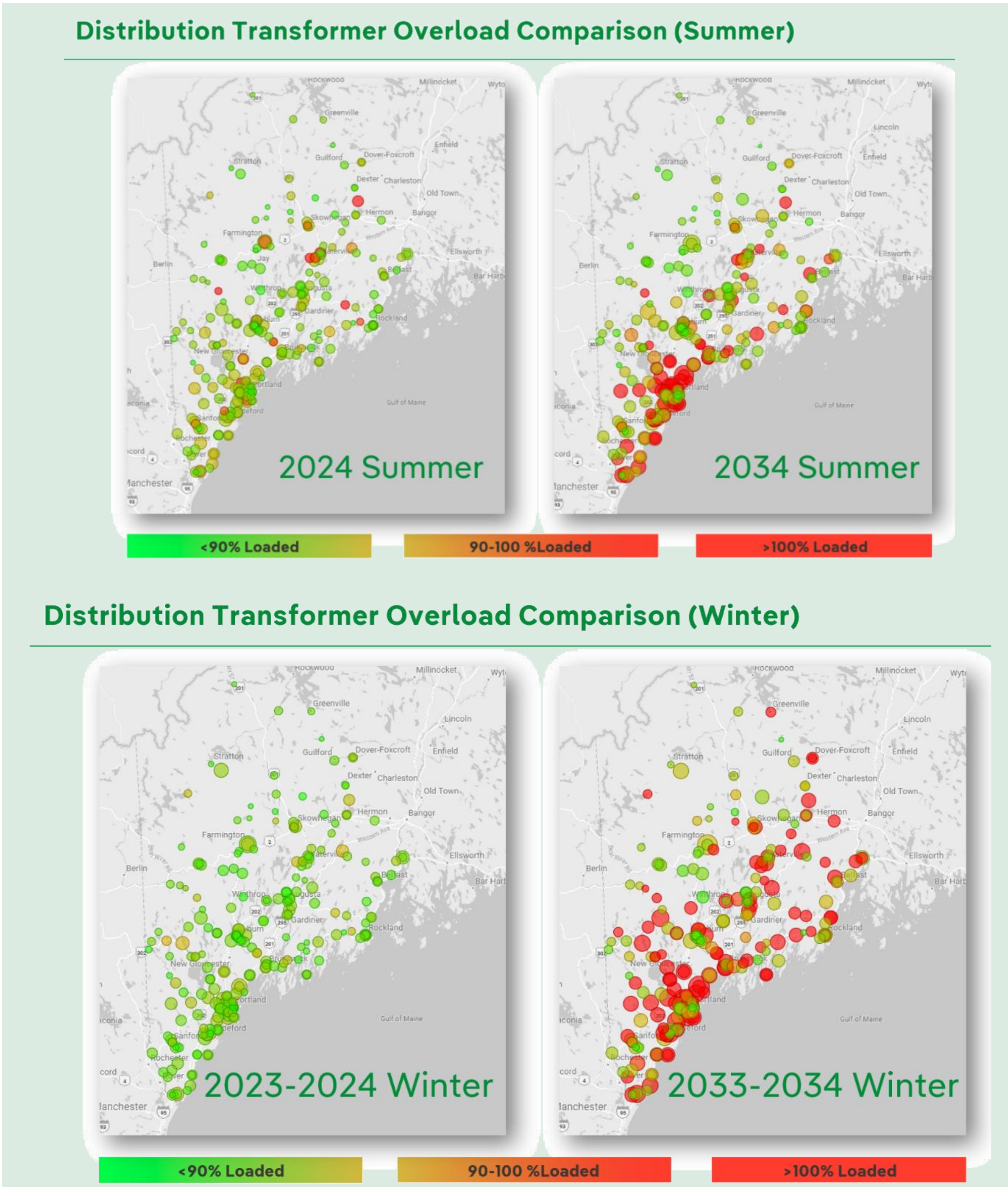
Thermal Overloads	2034 (Winter)		2034 (Summer)		2034 (Day Min load)		2034 (Unique Overloads)	
	Violations	Total	Violations	Total	Violations	Total	Violations	Total
Distribution Substation Transformer	114	45%	71	28%	16	6%	115	46%
Distribution Circuit	107	360 mi.	78	124 mi.	34	40 mi	123	25%
Voltage Violations	Violations		Violations		Violations		Violations	
Distribution	153 circuits		121 circuits		27 circuits		39 circuits	

Overloads and voltage violations in summer and winter peak load conditions are driven by the forecasted electrification of heating and transportation and tend to occur in densely populated southern and coastal regions of Maine. During the lightest load hours in many rural areas, strong solar output and low local demand create reverse power flow and voltage rise. This is where overvoltage and occasional reverse flow thermal constraints during daytime minimum loading are more common. Most of the 115 substation transformer overloads are driven by winter peak demand exceeding rated capacity (114), followed by summer peak (71), while 16 substations are projected to experience reverse power flow at daytime minimum load.

[25] The first three columns show the number of violations during the winter peak, summer peak and daytime minimum load snapshots (the three snapshots driving the majority of violations) and the fourth column shows the number of unique assets forecasted to experience thermal overloads or voltage violations. The first three columns do not sum to the fourth column because some assets are forecasted to experience violations during multiple snapshots.

Exhibit 4.5: Substation Loading in 2024 and 2034 Absent Capacity Expansion

Absent investments to expand network capacity, there will be significant shortfalls in the ability to provide safe and reliable power as the capacity needs grow to support increasing demand from electrification to meet the state's climate goals.



Distribution system needs vary across CMP's service territory, as different challenges face urban and rural areas. In more densely populated southern Maine, most grid needs are driven by increased demand, while in more rural and less densely populated areas, challenges are related to increased DERs and reverse power flows.

Case study: High Load, Low DG Circuit in Southern Maine

Sub-circuit level analysis of Circuit 688D1, serving Kittery and York, illustrates an example of a high load, low DER circuit in a densely populated area of southern Maine. This area is projected to see 123% forecasted growth driven by EV and heat pump adoption, creating significant thermal and voltage needs during winter and summer peaks under both the 50/50 and 90/10 forecasts.

688D1 - Driving Needs/Upgrades

Need Type	Summer Daytime Peak	Summer Evening Peak	Winter Evening Peak	Spring Minimum	Daytime Minimum	Evening Minimum
			50/50			
Thermal Overloads	40	29	29	1	1	0
Voltage Violations	1,482	1,306	1,450	267	0	0
			90/10			
Thermal Overloads	53	33	44	1	1	1
Voltage Violations	1,523	1,467	1,489	334	0	0

Case Study: Low Load, High DG Circuit in Rural Maine

Circuit 870D2 in Winslow represents the opposite case. Winslow is in a rural area and is projected to see 68% forecasted electric growth and high DG penetration, with 13 MW forecasted by 2034. It shows needs during low load with high distributed generation output, the kind of condition that can drive overvoltage and reverse flow constraints along longer rural lines. DER driven needs are more prevalent in rural areas with land available for development of DERs.

870D2– Driving Needs/Upgrades

Need Type	Summer Daytime Peak	Summer Evening Peak	Winter Evening Peak	Spring Minimum	Daytime Minimum	Evening Minimum
			50/50			
Thermal Overloads	0	0	0	1	9	0
Voltage Violations	0	0	0	58	156	0
			90/10			
Thermal Overloads	0	0	0	0	9	0
Voltage Violations	0	0	0	56	68	0

4.3.2. Transmission Needs

On the transmission side, CMP's contingency analysis and reliability assessment across eighteen study scenarios identified thermally overloaded transmission transformers and transmission lines and instances of low and high voltage violations and voltage collapse. If left unaddressed, these constraints could be barriers for meeting Maine's climate goals.

Exhibit 4.6: Transmission Needs Summary

Transmission Needs Summary

Thermal Overloads	2034 (Winter)		2034 (Summer)		2034 (Day Min load)		2034 (Unique Overloads)	
	Violations	Total	Violations	Total	Violations	Total	Violations	Total
Transmission Transformer	30	24%	23	18%	1	1%	34	29%
Transmission Line	84	316 mi.	35	255mi.	10	60 mi.	107	18%
Voltage Violations	Violations		Violations		Violations		Violations	
Transmission	348 instances		284 instances		161 instances		76 Load-Driven 221 DER-Driven	

The IGP transmission analysis identified 34 unique overloaded thermal transformers driven by summer, winter, and midday minimum load levels. When there is an outage at one end of the transmission line, the transformer at the other end is typically overloaded to transport the power needed to the entire load area.

The analysis identified 107 unique overloaded thermal transmission lines. Of these, 76 were overloaded by more than 110 percent of their long-term emergency rating and 45 were overloaded by more than 150 percent of their long-term emergency rating. CMP determined that most of the concerns were identified during the winter and summer evening peak scenarios where load levels are high and solar is not generating due to time of day.

Winter loadings show significant overloads even with the increase in rating normally achieved during the colder winter months which allows for more capacity on the system before the long-term emergency rating is reached. This indicates loading conditions that are much higher due to many emerging conditions.

During the transmission analysis, there were over 750 voltage violations on the system. These violations include scenarios of low voltage, high voltage, and voltage collapse conditions. Low voltage conditions commonly occur from a sudden increase in load or loss of a major transmission source into the area. High voltage generally occurs from a sudden loss of load or high generation without voltage support.

4.4. Climate Change Protection Plan Results

CMP's Climate Change Protection Plan (CCPP) is composed of two foundational documents: the Climate Change Vulnerability Study (CCVS) and the Climate Change Resilience Plan (CCRP). The CCVS provides a comprehensive assessment of the potential impacts of climate change on CMP's assets and operations, utilizing downscaled climate projections and extensive stakeholder engagement. It identifies key climate hazards such as severe storms and wind, flooding (both inland and coastal), extreme heat, and wood decay as presenting high exposure and vulnerability to CMP's infrastructure. The study also highlights operational vulnerabilities across multiple departments, including asset management, vegetation management, and emergency response, emphasizing the increasing challenges posed by climate change.

Building on the CCVS findings, the CCRP outlines a framework and specific resilience measures aimed at mitigating these identified risks. The plan emphasizes four resilience objectives: strengthening assets and operations to withstand climate hazards, enhancing the capacity to anticipate and absorb impacts, improving response and recovery capabilities, and advancing adaptive strategies to evolve with changing climate conditions. Key resilience measures include upgrading physical infrastructure with stronger materials such as steel poles and fiberglass crossarms, expanding the use of spacer cable and tree wire to reduce vegetation-related outages, targeted undergrounding of vulnerable distribution lines, and enhanced vegetation management programs like accelerated Ground to Sky trimming. The CCRP also addresses operational improvements such as advanced management systems, improved load forecasting, incorporating climate projections, workforce safety enhancements, and robust customer outreach.

Together, these documents form CMP's Climate Change Protection Plan, which serves as a guide for integrating climate resilience into CMP's planning, investment, and operational strategies. CMP commits to ongoing evaluation and adaptation of these measures to address evolving climate risks, ensuring the continued delivery of safe, reliable power to its customers while safeguarding its workforce and infrastructure against the increasing threats posed by climate change.

High Exposure Climate Hazards:	Key Vulnerabilities to those Climate Hazards:
Storm Events and Wind	Highest vulnerabilities to **overhead conductors** and **line structures**, as well as other **elevated assets**, from impacts of wind and downed trees; **distribution, transmission, and substation systems all include assets with high vulnerability**
Flooding (Inland and Coastal)	Highest vulnerabilities to **ground-mounted assets**, such as substations, and any **underground assets** such as buried conductor and structure foundations
Heat Events	Higher vulnerability for **most distribution, transmission, and substation assets** such as transformers and circuit breakers
Wood Decay	High expected vulnerability of **transmission and distribution wooden poles**, as well as on overhead assets and ground-mounted **assets exposed to falling vegetation**
Wildfire (low change from current exposure, but high impact)	Periods of high, very-high, or extreme Fire Weather Index pose a **significant threat to utility assets**, which are generally not designed to be exposed to fire

Although the IGP focuses mainly on capacity needs resulting from the application of the CELT forecast to the electric system for the 10-year planning period, as directed by the IGP Order, the results of the Climate Change Protection Plan relate closely to the primary IGP results. When a thermal overload or voltage violation is identified, the response must not only resolve the immediate capacity constraint but also ensure that the solution is resilient to weather and climate hazards. For example, if a circuit experiences a thermal overload, the corrective action, whether through asset upgrades or operational measures, should incorporate assets or designs that can withstand increased storm intensity, flooding, or other climate-related risks. This integrated approach ensures that capacity solutions also enhance the system's resilience and reliability under evolving climate conditions.

Distribution automation allows CMP's distribution system to be smarter and more efficient, by harnessing the power of technology to increase reliability and resiliency for customers. By installing distribution automation devices, CMP is more responsive to outages, allowing system operators at the Energy Control Center to identify outages and take action to restore power remotely.

Expanding system redundancy through the installation of additional distribution ties, automatic transfer systems, and strategically placed backup circuits also allows CMP to restore power faster and lower the number of customers impacted by outages. CMP prioritizes new and upgraded circuit ties by focusing first on circuits without an existing tie followed by areas with limited tie capability, prioritizing worst performing circuits and utilizing benefit-cost analyses.

Without such technologies and devices, customers will experience longer and more frequent outages. A recent example of the importance of backup circuits is an outage incident that occurred on January 29, 2025. A motor vehicle accident in South Portland opened circuit 650D1 at the substation breaker, causing an outage for 2,328 customers. Backup circuits were utilized to restore 2,258 customers (all but 60 of the affected customers) promptly after the scene was made safe. The total repair time was roughly six hours. Without enhanced backup in this situation, all 2,328 customers would have experienced an outage lasting that full six hours.

Circuit hardening is the practice of making CMP's distribution system more resilient to severe weather events. CMP analyses distribution circuits by zones of protection to determine the most effective areas of the system to focus hardening efforts on based on customer exposure, high outage risk and customer impact. Three year historic outages are analyzed to determine the most effective method of hardening. While distribution automation and circuit redundancy reduce the impact of outage incidence, hardening reduces the chances of weather damaging the system and preventing outages. Hardening methods include reconductoring bare wire to insulated spacer cable, using higher class wood poles or steel poles to prevent pole damage, and undergrounding select sections of a distribution circuit to remove exposure to weather damage.

Asset condition and reliability needs also arise independently of capacity constraints. A circuit may have sufficient capacity and voltage performance to handle current and projected loads, including DERs, yet still require asset replacements due to aging or deteriorated infrastructure. For instance, poles that are too small, old, or weakened by decay or infestation may not reliably withstand storms or other hazards, even if the circuit load is within limits. In such cases, proactive replacement with stronger materials, such as higher-class wood poles or steel poles, is necessary to maintain system reliability and reduce outage risk. These condition-driven needs are identified through routine inspections and assessments and are prioritized alongside capacity-driven needs to ensure a robust and resilient grid.

By addressing both capacity-related and condition-driven asset needs in a coordinated manner, CMP aims to deliver a reliable, resilient, and climate-adaptive electric system that meets the evolving demands of Maine's customers.

4.5. Time-series Modeling Progress and Utilization

Time series modeling is an approach to forecasting electricity demand that involves analyzing historical load patterns and their relationship to factors such as weather, seasonality, and economic activity. For utilities, these models can improve short-term operational planning and long-term infrastructure decisions by providing a more complete picture of daily and seasonal variations in future load behavior. However, implementing time series forecasting requires significant investment in data quality, modeling expertise, and integration with existing planning processes.

Time series modeling can be applied to selected circuits, leveraging the capabilities of existing software. However, the process currently depends heavily on manual intervention at each stage — from downloading data from the SCADA system, performing quality checks and cleansing, to reformatting the data appropriately for input into the CYME model. This manual workflow can be labor-intensive and time-consuming, particularly when data quality issues arise, potentially requiring several days or even weeks of effort to complete.

CMP developed a roadmap to implementing time series forecasting and analysis, discussed in more detail in Section 7, which includes AMI data integration and new forecasting tools. As new tools and capabilities are implemented, CMP will begin to cross check snapshot results against hourly findings, refine the timing of projects, and identify opportunities where operational strategies could defer or reduce capital costs without compromising reliability or service quality.

4.6. Data Availability

Pursuant to 35-A M.R.S.A. §3147(5) CMP has made certain documents available for public access, including: the transmission planning modeling infrastructure inputs and a planned transmission and distribution projects list, which are available in the appendices to this report.

Additional information related to this filing, including Critical Energy Infrastructure Information (CEII), customer-specific data, market-sensitive information from interconnection queues, confidential business information, and other proprietary or sensitive planning/model data, has not been proactively provided as part of this IGP.

To access confidential and sensitive materials used in developing CMP's Integrated Grid Plan, interested parties must submit an application to Chris Morin, Senior Director of Integrated System Planning, at gridandclimateplanning@cmpco.com or by mail to 83 Edison Drive, Augusta, ME 04336.

Applications should include:

1. **Requesting Individual or Organization**: Clearly identify the party requesting the data.
2. **Detailed Data Request**: Specify the data needed in as much detail as possible.
3. **Purpose Statement**: Explain the intended use of the data. If multiple data sets are requested, specify the purpose for each.
4. **Cybersecurity and Confidentiality Measures**: Describe the protections in place on devices or technology where the data will be reviewed or downloaded to prevent inadvertent disclosure.
5. **Existing Confidentiality Protections**: Outline any additional current confidentiality processes relevant to the request and protection of data requested.

CMP will evaluate each request to determine if access can be granted and under what conditions, such as a protective order, non-disclosure agreement, and/or limited in-person review at CMP's offices. This process aims to balance transparency with the need to protect confidential data. CMP will strive to respond to requests by aggregating, anonymizing, or redacting information to safeguard sensitive material.

4.7. Alignment with Maine's Greenhouse Gas Emissions Reduction and Climate Policies

The electric power grid is foundational to meeting Maine's climate goals. Maine's climate roadmap, *Maine Won't Wait*, and the recent Maine Climate Council Annual Report on progress toward the *Maine Won't Wait* goals (released December 2025), highlight the need to "[p]lan for future grid needs at both the transmission and distribution levels, including growth and increased resilience to storm impacts . . . ." Similarly, *Maine Pathways to 2040*, which evaluates alternative pathways by which Maine might meet its climate and energy goals, finds that widespread electrification of transportation and heating and continued decarbonization of the electric supply are key strategies to achieving the state's climate goals. This means the grid CMP plans today must be ready for a future with more electric heat pumps, more electric vehicles, and more clean generation connected to the distribution and transmission network.

By using the ISO-NE 2024 CELT forecast, which aligns with state policy goals, as the inputs to CMP's load forecast described in Chapter 3 the load forecast and needs identified incorporate the impacts of electrification needed to meet state climate goals. The ISO-NE 2024 CELT forecast assumes high levels of heat pump and electric vehicle adoption over the 10-year forecast, reaching between 40-50% heat pump penetration by 2035[26] and an incremental 340,394 EVs adopted over 10 years[27].

While this first 10-year grid plan does not reach 2040, longer term studies, including the Maine Pathways to 2040 Report and ISO-NE 2050 Transmission Study, provide insights on how to support the state's climate goals in subsequent planning periods. Both reports project that

[26] ISO-NE Final 2024 Heating Electrification Forecast. https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf
[27] ISO-NE 2024 Final Transportation Electrification Forecast. https://www.iso-ne.com/static-assets/documents/100011/transfx2024_final.pdf

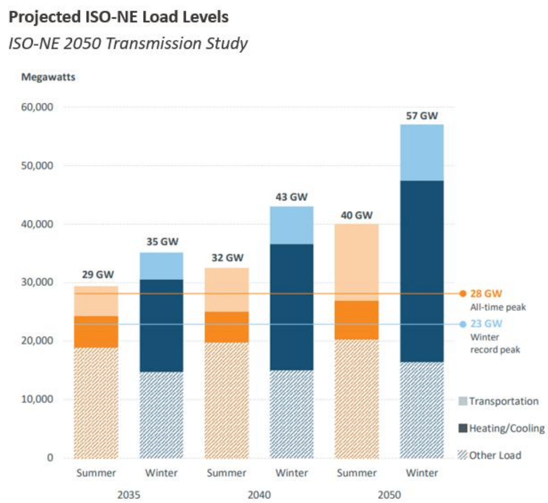
demand will continue to rise significantly beyond 2035 and could more than double by 2050 from the current demand baseline, as shown in Exhibit 4.7 below. The Maine Pathways to 2040 Report assessed six pathways, including the Core Pathway, which assumes medium levels of flexibility, a No Flexible Load and High Flexible Load Pathway. Because of the growth shown across all pathways, a significant expansion of distribution capacity is needed across all pathways. This means that near-term investments to expand capacity are likely "no regrets" and that "right-sized" solutions should be considered to avoid multiple upgrades to the same equipment between now and 2050. In addition, flexibility is a key strategy that should be pursued to mitigate peak demand growth and complement investments to expand capacity.

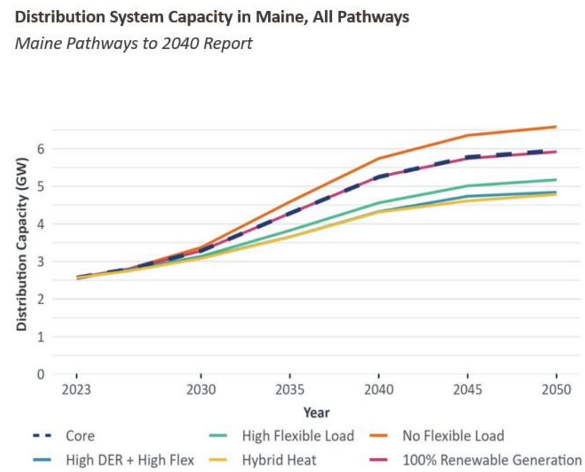
Specifically, the Pathways report also cautions that delays in transmission and distribution build-out could constrain clean power delivery, limit access to low-cost generation, slow electrification adoption, and even pose reliability risks; these capacity needs are discussed in more detail in Sections 3 and 4 of this IGP. Pathways also highlights the importance of tracking electrification trends and developing flexible load capabilities to manage EV charging and heat pump integration, which are discussed in more detail in Sections 2 and 3. Since Pathways was published, Maine has adopted a Clean Energy Standard (CES), which establishes a requirement for 100% clean electricity by 2040, building on the Renewable Portfolio Standard's 90% renewable target by 2030. The CES expands eligible resources to include low-carbon options such as nuclear and large hydro, introduces tradable clean energy credits, mandates utility-scale procurements, and creates a new Department of Energy to oversee these goals. We are cognizant of potential policy changes going forward, and believe that an approach emphasizing near-term investments to serve known needs, but which can support more attenuated needs, aligns with the Pathways report.

CMP's near-term investments are structured to advance affordability while delivering cost-effective upgrades that enable Maine's energy transition, including planned electrification and growing clean energy penetration, by prioritizing multivalue, rightsized projects and designing solutions as cost-effectively as possible. These investments are guided by the overarching principles of keeping customer costs affordable and facilitating the State's climate action and greenhouse gas reduction policies, with commitments to pursue alternative funding sources such as U.S. DOE loans and grants to mitigate rate impacts. Proactive planning will expand capacity where needed to interconnect and manage distributed energy resources, support load growth from electrification, and maintain stability and reliability, thereby improving affordability by enabling least cost, well informed grid investments. CMP recognizes that precise cost and rate impacts are often indeterminate until projects are fully scoped and in service; accordingly, CMP's approach emphasizes staged development and value focused execution to manage uncertainty while ensuring clean power can be delivered reliably and at the lowest reasonable cost.

By aligning investment timing and sizing with demonstrated needs, CMP's plan aims to balance immediate reliability with longer-term transition requirements, sustaining affordability for all customers, including disadvantaged and vulnerable populations, while enabling Maine's climate goals and maintaining flexibility to adapt to potential policy changes over the planning horizon..

Exhibit 4.7: Projected Load Growth, ISO-NE 2050 Transmission Study [28] and Maine Pathways to 2040 Report [29]





Proactive grid investments and strategies are needed to ensure that capacity is available to meet rising demand while keeping the system reliable and affordable. At the same time, strong distributed generation growth requires better voltage control and careful attention to the times and places where reverse power flow can create local constraints. Solutions are needed to address current and future reverse power flow issues so that the grid can not only accommodate but also leverage and optimize continued growth in DERs. The resilience work described in the Climate Change Protection Plan complements this effort by addressing the effects of a changing climate so that customers experience fewer and shorter interruptions even in the face of more frequent and severe storms.

The investments made over the next ten years to expand capacity and improve reliability will be foundational to enabling forecasted demand growth, increasing renewables, and increasingly complex use of the system. In addition, foundational investments to enable demand flexibility and DER management will also be important to mitigate future levels of demand growth. The next chapter provides an overview of the solutions identified and evaluated to meet the needs identified through the IGP modeling, including a scorecard category for 'Policy Alignment'.

4.8. Milestone 2 Stakeholder Feedback

Stakeholders provided the following feedback related to CMP's Milestone 2 needs assessment.

Impact of Federal Policy Changes on Forecasts

- Stakeholders questioned whether CMP would revisit assumptions given recent reductions in federal incentives for EVs, heat pumps, and solar adoption. (CMP acknowledged these changes and noted that while the 2025 ISO-NE CELT forecast reflects some downward

[28] ISO-NE 2050 Transmission Study. (2024_02_14_pac_2050_transmission_study_final.pdf)
[29] ISO-NE 2050 Transmission Study. (Maine Pathways to 2040: Analysis and Insights)

revisions, the Commission requires use of the 2024 CELT forecast. CMP emphasized that the plan is directional and not a cost recovery mechanism, and that detailed project-level analysis will incorporate updated data.)

Granularity and Circuit-Level Analysis

- Stakeholders asked how CMP ensures investments in target areas with the greatest need rather than applying system-wide solutions. (CMP has explained to stakeholders that the needs assessment identifies categories of needs and severity, while project-level decisions will consider asset condition, reliability, and likelihood of occurrence. CMP has further explained to stakeholders that Milestone 3 would outline solution options without prescribing a single preferred solution.)

- Stakeholders commonly questioned whether CMP analyzed every circuit and whether Milestone 3 will provide cost estimates or preferred solutions for specific circuits. (CMP confirmed that all circuits were reviewed and grouped by severity and drivers such as load growth vs. DER penetration. CMP explained that Milestone 3 would present solution alternatives and cost ranges but will avoid rigid prescriptions to allow stakeholder input.)

Duration and Nature of Violations

- Stakeholders asked if CMP assessed how long overloads or voltage violations persist (e.g., minutes vs. hours). (CMP indicated that time-series analysis will be incorporated in Milestone 3 to distinguish short-duration issues that could be addressed by non-wires alternatives (e.g., DER curtailment) from persistent needs requiring infrastructure upgrades.)

Integration of Reliability and Resiliency

- Stakeholders emphasized considering reliability and resiliency alongside capacity needs. (CMP confirmed these factors are part of the scorecard for evaluating solutions and highlighted findings from its Climate Change Protection Plan, including storm impacts, aging infrastructure, and limited circuit tie capability.)

Future Flexibility and Feedback Cycle

- Stakeholders asked how CMP will adapt to new technologies, financial constraints, and evolving forecasts over time. (CMP noted that the IGP process repeats every five years and that project-specific approvals will incorporate updated data and stakeholder input. Additional regulatory processes such as CPCN filings, NWA reviews, and rate cases provide checkpoints for adjustments.)

05. Solutions Identification and Evaluation

Building on the forecast and system needs identified, this section provides an overview of the range of potential solutions to address system needs over the next five and ten years and how they will enable delivery of the state's climate goals.

Key Takeaways:

- Over the next 10 years, CMP expects significant load growth driven by the electrification of transport and heating and growth in DERs such as solar and storage to meet Maine's ambitious climate goals.
- The current network does not have the capacity to meet this growth. It takes multiple years to design and build electric network infrastructure, so proactive planning is critical.
- Addressing imminent and forecasted system needs requires no-regrets near-term infrastructure investments to expand system capacity while simultaneously testing alternative solutions and laying the foundation for new solutions to scale.

5. Solutions Identification and Evaluation

As described in Section 3, peak load is projected to grow between ~60-80% over the next 10 years, driven by the adoption of heat pumps and electric vehicles, and the system's peak is projected to shift from the summer to winter. The combination of load growth and increasing penetration of DERs is creating capacity constraints on CMP's grid, which are summarized in Section 4. This section provides an overview of potential solutions to address capacity constraints, including new infrastructure investments, technologies and programs, that can meet grid needs over the next 10 years and provide a foundation for enabling Maine's 2040 and 2045 climate goals.

This section will:

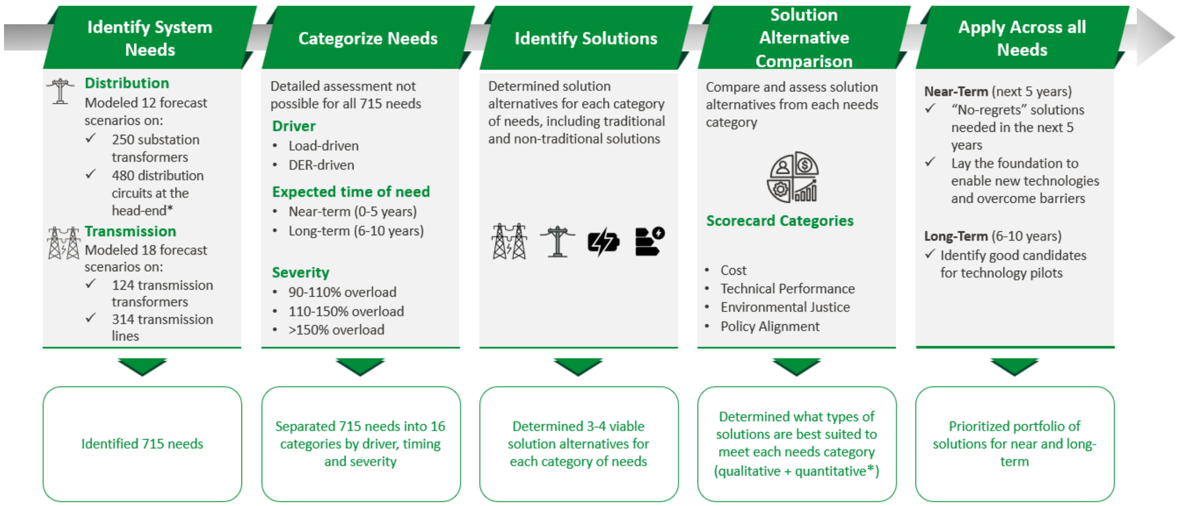
- Provide an overview of the scorecard framework used to identify and evaluate solutions to address grid constraints arising from forecasted demand and DER growth
- Provide an overview of the investments required to meet system capacity needs in the next 5 years
- Outline the solutions that can meet system capacity needs in the next 6-10 years, including foundational investments and dependencies needed to enable and scale new solutions

5.1. Capital Project Evaluation and Alternative Comparison Framework

As described in Section 4, CMP developed a comprehensive view of the system's likely future needs through distribution substation, circuit, and sub-circuit level analysis across 12 different forecast scenarios, as well as transmission analysis at the transformer and line level utilizing 18 forecast scenarios. The analysis identified significant distribution and transmission constraints, totaling 715 unique needs.

Given that detailed solution comparative analysis, engineering, and cost estimation development for all 715 needs identified through the IGP process was not feasible or practical, CMP took the approach of categorizing the needs into similar groups for evaluation. Considering both traditional and non-traditional solutions, CMP identified 3-4 potentially viable solutions best fit to address each category of needs. Using the scorecard framework proposed by the DOER and adopted by the MPUC, CMP then compared solution alternatives across cost, technical performance, EEEJ and policy alignment categories. Finally, CMP prioritized and developed a set of solutions to address near-term and long-term needs.

Exhibit 5.1: Solutions Identification and Evaluation Process



Detailed Circuit Level Analysis on 70 sample circuits from end to end

5.1.1. Needs Categorization

The needs assessment identified significant distribution constraints, including 166 near-term thermal overloads and 72 long-term overloads on distribution substations and circuits, as well as 39 thermal or voltage issues driven by reverse power flows from DERs over the next 10 years. At the transmission level, the analysis identified thermal overloads on 34 transformers and 107 circuits, as well as 76 low voltage violations driven by load and 221 high voltage issues driven by DERs.

While not all needs should be treated the same, many needs exhibit strong similarities. To facilitate the assessment for the 715 identified needs, CMP grouped them based on the following considerations:

- Expected time of need: CMP divided needs into near-term (0-5 years) and long-term (6-10 years) based on the timing of the expected grid constraint, taking into consideration technology readiness, foundational enabling technologies and the need for no regrets investment to meet immediate needs.
- Severity of overload compared to the rated capacity of the equipment:
  - Low Severity (≤110% Overloading): A violation is occurring, but reduced likelihood of frequent, widespread disruptions in service
  - Medium Severity (110%–150% Overloading): Higher likelihood of frequent, widespread disruptions in service
  - High Severity (>150% Overloading): Very likely to cause significant adverse effects on service

- Driver: Load-Driven and DER-driven needs can have different sets of solutions, as well as different regulatory treatment. If the system need is triggered by demand, ratepayers will share the costs, while if the system need is triggered by a DER interconnection, the costs are generally borne by the developers.
- Type of Violation: Thermal overloads and voltage drops often share the same root cause: excessive current and reactive power imbalance. Fixing the thermal overload usually restores reactive power margins, which improves voltage. On the transmission system, both thermal and voltage needs were considered because larger geographic coverage of transmission system reduces likelihood that thermal solutions will also solve voltage issues.
- Equipment: CMP's IGP solutions evaluation focused on critical network assets, circuits and transformers, as their replacement or enhancement typically requires sizeable capital investment. Ancillary component constraints, such as fuses, will be routinely addressed as part of proactive inspection or broader capital projects.

This resulted in 16 categories for scorecard evaluation: 10 for distribution and 6 for transmission, shown below in Exhibit 5.2. The distribution categories are predominantly focused on thermal overloads because in most cases solving thermal overloads solves the corresponding voltage violations. These categories were designed such that viable solution alternatives will be similar for the needs within each category.

Exhibit 5.2: Categorization of Needs - Distribution and Transmission

					Category	# of Needs
Needs	Distribution	Near term Thermal Violations	Circuit	Low severity	1	10
				Medium severity	2	43
				High severity	3	28
			Transformer	Low severity	4	10
				High severity	5	75
		Long term Thermal Violations	Circuit	Low severity	6	41
				High severity	7	1
			Transformer	Low severity	8	27
				High severity	9	3
		DER-driven Violations[1]			10	39
	Transmission	Thermal Violations	Transmission line	Low severity	11	29
				Medium severity	12	43
				High severity	13	35
			Transformer[2]		14	34
		Voltage Violations[2]			15	76
		DER-driven Violations[1]			16	221

Not further categorized because: 1) DER-driven violations are customer-specific; 2) transmission voltage violations are inherently specific; or need is attenuated.

Transmission network planning differs significantly in timescale from distribution planning and is governed by distinct transmission planning standards. The planning difference is due to voltage levels, geographic scope, regulatory complexity, and planning objectives associated with the lines. With a multi-year planning timeline, integrated transmission planning frameworks adopt a 10-year horizon without subdividing it into shorter intervals. This approach aligns with the nature of transmission investments, which are capital-intensive, requiring more time for permitting and long-term coordination across jurisdictions and markets.

Voltage stability is one of the key elements of transmission planning, given the nature of long distance and bulk power transfer. Dedicated mitigation is also often required for low or high voltage in planning and operational standards.

5.1.2. Solutions Identification

Once needs were identified and categorized, CMP identified potentially viable solutions for each category, considering the suitability of solutions to address lower and higher severity needs. The toolbox of solutions to address needs, including thermal overloads and voltage violations, includes:

Solution	Definition	Pros / When Suitable	Cons / When Not Suitable
Customer-controlled Solutions			
Demand Response	Shift consumer resources to off-peak times to mitigate peak demand	✓ Reduces peak demand, potentially delaying or eliminating need for upgrades	× Relies on customer participation × Limited impact if load flexibility is low
DER Management	A local control system designed to coordinate DERs within a specific area, reduce upstream stress	✓ Offsets load ✓ Local generation source could provide some resiliency benefits	× Intermittent output may not serve load unless paired with battery storage × Will not always align with peak demand periods
Solutions for Lower-severity Needs			
Hardening and Automation	Strengthen the physical and operational resilience of electrical circuits against external threats such as severe weather, physical damage, or cyberattacks	✓ Reduces outages and improves resilience ✓ Enables remote monitoring and control	× Do not address thermal or voltage overloads
Shift System Load	Where feasible, redirect load to a nearby circuit	✓ Mitigates overloads when adjacent circuits have available capacity ✓ Typically less expensive than upgrading the circuit	× Requires appropriate adjacent circuit conditions × Limited as a long-term solution
Cooling Retrofit	Retrofitted transformer with forced air or oil cooling systems to improve thermal performance and load handling	✓ Extends life of equipment under thermal stress ✓ Cost effective compared to full replacement	× Only suitable for certain equipment × Doesn't increase capacity × Maintenance intensive; limited impact in extreme heat
Circuit Upgrade	Reconductoring the circuit with larger, higher capacity wire	✓ Increases capacity and reliability for long-term growth; addresses thermal and voltage overloads	× Requires infrastructure investment; potential ROW limitations
Voltage Regulator	A device installed on power distribution lines to automatically maintain a stable voltage level for customers by adjusting voltage up or down as load conditions change	✓ Improves voltage stability ✓ Can be operated/maintained independently	× Ineffective for thermal overloads × Limited benefit for fast-changing loads or DER variability
Capacitor Banks	Improve voltage stability and reactive power support in distribution networks by deploying mechanically switched capacitor banks at key locations	✓ Improves voltage stability ✓ Insignificant capital investment	× Ineffective for thermal overloads × Limited benefit for fast-changing loads or DER variability
Battery Energy Storage System (BESS)		✓ Can serve peak shaving and reliability needs ✓ Can mitigate variability of intermittent generation	× High upfront costs and 5-15 year lifespan × Potential safety and environmental concerns

Solution	Definition	Pros / When Suitable	Cons / When Not Suitable
	BESS can charge during off-peak hours and dispatch during peak load conditions and can be charged during times of excess solar output, reducing or mitigating reverse power flows.		× Regulatory uncertainty
Microgrid	A localized energy system with integrated loads and DERs that can operate connected to the main grid or independently (islanded).	✓ If capable of islanding, can provide reliability	× High upfront costs; complex design and operation
		✓ Could be implemented with advanced communications scheme to coordinate with the full grid, with appropriate protection systems to protect the microgrid and the full grid, and with microgrid control system like ADMS and DERMS	× Potential regulatory barriers/uncertainty
			× Benefits are localized
			× Full scope of generation, voltage/thermal support, and distribution infrastructure needed within the microgrid
Dynamic Line Ratings	Optimizes the current-carrying capacity of transmission lines by using sensors and software to adjust for factors like wind speed and temperature	✓ With real-time line capacity data, operators could optimize power flows on transmission lines depending upon the weather	× Difference between prediction and actual realized performance, leading to reliability concerns.
			× Benefits limited by line sections with varying conditions.
Flexible Inter-connections	An advanced control system that balances power regionally by optimizing transmission paths and capacities.	✓ Could allow interconnecting load and generation customers to interconnect within prescribed operating envelopes to reduce interconnection costs, enable DER integration	× High Cost & Complexity – Advanced devices (FACTS, power flow controllers) require significant investment and technical expertise.
			× Operational Uncertainty – Real-time control depends on accurate data and coordination; errors can impact reliability.
	Allow DERs to interconnect to the distribution system with agreed operating constraints that reduce the need for system modifications		× Regulatory & Planning Issues – Lack of clear standards and planning frameworks can delay deployment.
Solutions for Higher-severity Needs			
Circuit Tie	Build a circuit tie and redirect load to a nearby circuit and is typically less expensive than upgrading the circuit	✓ Improves flexibility for load transfer, and alternate feed during outages	× Requires compatible voltage and protection schemes
		✓ Typically less expensive than upgrading the circuit	× Limited benefit when adjacent circuits are constrained

Solution	Definition	Pros / When Suitable	Cons / When Not Suitable
New Circuit	Build a new line to add capacity	✓ Adds redundancy, capacity, reliability, load balancing	× Requires infrastructure investment; potential ROW limitations
Transformer Upgrade or Parallel Transformer	New or upgraded transformer with higher rated capacity	✓ Increases capacity; improves reliability	× Limited benefit if upstream circuit is constrained × May not solve voltage issues if feeder is long
Substation Upgrade or New Substation	Improve and optimize the capacity of the system by new topologies and/or substations.	✓ Adds capacity; improves reliability ✓ Reduces line loading ✓ Supports future DER integration	× Long lead time × Higher investment
STATCOM	Static Compensator is a power electronic device used in electrical power systems to provide fast-acting reactive power compensation and voltage support	✓ Improves voltage stability and power quality; effective for DER integration	× Does not address thermal overloads × Higher investment
Synchronous Condenser	A rotating electrical machine, similar in construction to a synchronous motor, that operates without a mechanical load and is used to provide dynamic reactive power compensation and voltage support in power systems	✓ Improves voltage stability and power quality; effective for DER integration ✓ Support system inertia when it comes to dynamic stabilities ✓ Support HVDC operations	× Does not address thermal overloads × Higher investment

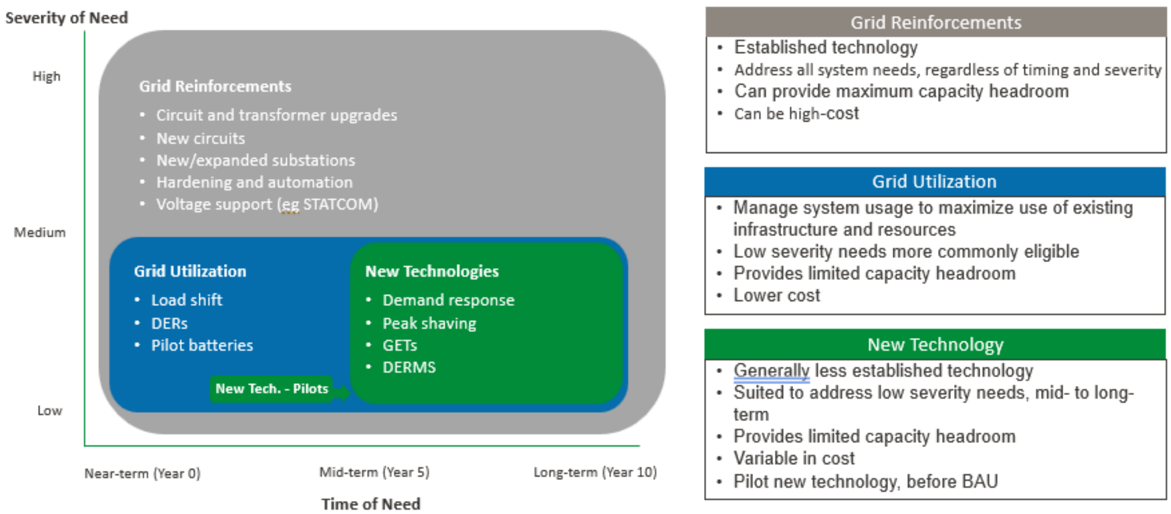
Enabling new solutions and advanced technologies to play a role in reliably meeting needs requires foundational systems and technologies as well as improved data accuracy and integration. CMP is working to further enhance data accuracy through initiatives such as GMEP, which is nearly complete, to ensure that system data is dependable to support informed decisions on the type and location of potential solutions. Completing the rollout of distribution automation (SCADA devices) across all feeders will provide full visibility and control, with centralized systems allowing grid operators to manage the grid efficiently, for example redirecting power to isolate outages. Integrating and leveraging more granular, hourly data from AMI and SCADA and transitioning to time series load forecasting and system planning enhances predictive analysis for electrification and DER integration. For example, insight into the duration and timing of overloads can inform whether alternative solutions such as battery storage or demand response could help meet a need. Foundational communications platforms, ADMS and DERMS, enable optimization of consumer load and DERs and help enable battery storage, demand response and flexible interconnections. These enabling systems and initiatives are discussed in more detail in Chapter 6.

Enabling Systems and Initiatives

Enabling System or Initiative	Status/Timing	Description
Grid Model Enhancement Project (GMEP)	In Progress – Nearly Complete	• Ensures accuracy in planning tools by aligning field assets with internal models
Automation; SCADA; Fault Location Isolation Restoration (FLISR)	In Progress (85% complete) - Targeting Completion by 2031	• Equipment necessary to establish visibility and control over the full distribution system • Allows reconfigurations of the system to isolate outages
Centralized Control and Visibility		• With field equipment providing visibility and control, allows grid operators to manage the grid effectively and efficiently
Advanced Load Forecasting	Planned (pending regulatory approval)	• Enables time-series planning • Allows processing of real-time and historical grid data more accurately • Enhances predictive analysis for electrification and DER integration
Advanced Distribution Management System (ADMS)	Planned (pending regulatory approval)	• Integrates outage management, SCADA, and distribution management into a single system • IT/OT integration • Depends upon enabling technology and control/visibility infrastructure to obtain proper data
Distributed Energy Resources Management System (DERMS)	Planned (pending regulatory approval)	• Dovetails with ADMS: ADMS focuses on grid operation, while DERMS focuses on DER orchestration • Can adjust DER dispatch within prescribed constraints • Can facilitate integration of DERs • Potential complexity with secure and reliable communication between grid operator and third-party owned DER • Potential regulatory uncertainty around interconnection and operating envelopes

The suitability of solutions depends on the severity and time of need. As shown in Exhibit 5.3, traditional grid reinforcements to increase capacity, such as circuits or transformer upgrades, new circuits or expanded substations, are generally needed to address medium to high severity needs to ensure system reliability and capacity. Solutions that improve grid utilization, such as load shifts, DERs and batteries, can be applicable for meeting lower severity needs in the short-term. At this level, a load shift and circuit tie can be a feasible solution for a minor constraint when a nearby circuit has sufficient available capacity. When overloads are forecasted to occur for long periods of time, traditional upgrades such as a circuit upgrade or new circuit will more reliably serve the increased demand. Flexible NWAs—such as demand-side management, battery-based peak shaving, and DER management—can also be operationally effective in certain circumstances, particularly when the overload is only forecasted to occur for a limited number of hours. Battery storage is suitable to mitigate peaks for 4-8 hours at a time, and demand-side management is currently most effective when targeting a limited number of hours per year[2]. In the longer term, newer solutions such as demand response, peak shaving, GETs and flexible interconnections, can in certain circumstances avoid or defer grid upgrades. These technologies can be piloted in the near-term, while foundational platforms such as ADMS and DERMS are implemented which will enable demand management and flexible interconnections to scale more effectively.

Exhibit 5.3: Solutions aligned with severity and timing of system needs



5.1.3. Scorecard Evaluation Methodology

The scorecard evaluation began with categorizing needs based on loading levels at the transformer and circuit head. A detailed study of seventy sample circuits was conducted in CYME to identify overloaded equipment, quantify the extent of overload on downstream circuits, and assess voltage impacts. Transformer overloads were not modeled in CYME because of the single point of potential overload. From the seventy circuits, approximately thirty were selected for further testing with three solution types: traditional upgrades; demand response or DERMS; and energy storage. These tests focused on near-term needs because modeling is most accurate for that time horizon. Addressing near-term needs also establishes a foundation for future cost-effective investments.

The analysis of these thirty circuits served a dual purpose: it provided detailed insights to refine assumptions and validated that applying those assumptions system-wide is a reliable approach. Lessons learned from the CYME analysis were then used to develop scorecards for each category using representative circuits. These scorecards incorporate more assessment criteria than CYME models alone. To estimate likely investment levels for addressing capacity needs, insights from the CYME analysis and scorecard comparisons were applied to near-term needs to determine viable solutions and develop unit-based cost estimates. Higher-level spreadsheet analysis, rather than full CYME modeling, was used for 166 needs to account for unique circumstances and refine cost estimates. For long-term needs, costs were extrapolated from short-term unit-based estimates to provide a forward-looking view of investment requirements.

CMP used the analysis above to inform the scorecard analysis, which is required by the IGP Order. Using the scorecard provided in Attachment D to the IGP Order, CMP evaluated potential solutions to grid needs to provide a higher-level, illustrative comparison of solution alternatives across the evaluation categories. This approach enables a structured assessment of options without implying false precision and is designed to facilitate meaningful engagement and informed feedback.

In response to stakeholder input, the scorecard includes:

- A qualitative assessment across each of the 15 criteria using a Low / Medium / High scale with a corresponding Red / Amber / Green (RAG) visual coding to enhance clarity and comparability
- An overall prioritization ranking for each solution evaluated

Exhibit 5.4: Scorecard

Description of System Need:		*Need summary*			
	Evaluation Category	**Comparative Assessment Scorecard**			
		Alternative A	Alternative B	Alternative C	Alternative D
Cost	Capital costs	*[low, medium, or high impact]*			
	Operations & maintenance costs				
	Avoided costs				
Technical Performance	Efficacy				
	Execution and schedule risk				
	Existing infrastructure optimization				
	Reliability & resiliency impact				
	Flexible management of customers' load and generation				
EJ	Equity				
	Emissions impact				
	Local environmental impact				
Policy Alignment	Peak load reduction				
	Electrification readiness				
	DER and renewables integration				
	Advances state energy and climate goals				
	Overall prioritization ranking	*[1st, 2nd, 3rd, 4th]*			
Scorecard Narrative:		*[Description of scoring process & results, with any necessary supporting data]*			

As shown above, the scorecard includes 15 criteria across four primary categories:

- Cost: Evaluation of the cost effectiveness of the solution, considering the upfront costs to implement the solution (capital costs), ongoing costs to operate and maintain the solution (O&M), and avoided costs.
- Technical Performance: Evaluation of the efficacy of the solution to solve the identified need, considering execution and schedule risk and the impact on reliability and resiliency. This category also considers whether the solution leverages existing infrastructure and flexible management of customers' load and generation.
- Energy Equity & Environmental Justice (EEEJ): Evaluation of equity impacts, considering the location of the solution and impact on disadvantaged communities, and emissions and local environmental impacts of the solution,

- Policy Alignment: Evaluation of the alignment of the solution with Maine's climate policy goals, including peak load reduction, electrification readiness, DER and renewables integration, and an overarching consideration of whether the solution advances state energy and climate goals.

CMP evaluated potential solutions using the following definitions and assessment criteria:

Costs				
Evaluation Category	**Definition**	**Comparative Assessment Scorecard**		
	Most Preferred	**Most Preferred**	**Middle**	**Least Preferred**
Capital costs	What is the **overall cost** to implement the solution?	**Low** Minimal utility investment	**Medium** Moderate utility investment	**High** Major capital investment required
Operations & maintenance costs	What level of ongoing **O&M effort** is expected?	**Low** Minimal maintenance needs	**Medium** Some recurring maintenance	**High** Regular and resource-intensive maintenance
Avoided costs	What is the potential for future **cost avoidance**?	**High** Significant deferral of major investments	**Medium** Some deferral or efficiency gains	**Low** Limited or no meaningful cost avoidance

Technical Performance				
Evaluation Category	**Definition**	**Comparative Assessment Scorecard**		
	Most Preferred	**Most Preferred**	**Middle**	**Least Preferred**
Efficacy	Does the solution support operation within **thermal and voltage limits**?	**High** Fully resolves the system need over multiple years	**Medium** Partially resolves needs over time	**Low** Limited ability to consistently resolve needs
Execution and schedule risk	What level of **execution or timeline risk** is expected?	**Low** Mature tech, simple build, short lead times	**Medium** Moderate complexity, some permitting /procurement risk	**High** High uncertainty, long lead times, complex dependences
Existing infrastructure optimization	Can existing infrastructure be **effectively leveraged**?	**High** Maximizes use of current assets	**Medium** Some reuse or efficiency gains	**Low** Replaces existing assets without improving utilization
Reliability & resiliency impact	Does the solution improve **reliability and resiliency**?	**High** Significantly reduces outage risk	**Medium** Some reliability improvement	**Low** Minimal or no impact on outage risk
Flexible management of customers' load and generation	Can customer load/generation be **flexibly managed**?	**High** Actively enables dynamic management/control	**Medium** Some interaction with flexible resources	**Low** No or limited enablement of customer-side flexibility

Environmental Justice				
Evaluation Category	**Definition**	**Comparative Assessment Scorecard**		
		Most Preferred	**Middle**	**Least Preferred**
Equity	Does affected grid infrastructure serve **disadvantaged community**?	**High** >=66% in DAC	**Medium** [33%, 66%] in DAC	**Low** <33% in DAC
Emissions impact	Does the solution **increase or decrease emissions**?	**High** Direct reduction of emissions	**Medium** Indirect reduction of emissions	**Low** Directly increases emissions
Local environmental impact	Does the solution require **development of new land**?	**Low** No new land use or reduces land use	**Medium** Moderate increase in land use	**High** Increases land use

Policy Alignment				
Evaluation Category	**Definition**		**Comparative Assessment Scorecard**	
	Most Preferred		**Middle**	**Least Preferred**
Peak load reduction	Does the solution **reduce peak load**?	**High** Significant peak reduction over multiple years	**Medium** Moderate, temporary, localized peak reduction	**Low** Negligible impact on system peak
Electrification readiness	Does the solution allow for **future load growth**?	**High** Substantially expands or future-proofs grid capacity	**Medium** Moderate additional grid capacity	**Low** Marginal or no improvement in grid capacity
DER and renewables integration	Does the solution enable **DER and renewable integration**?	**High** Directly promotes DER adoption or installs DER	**Medium** Enables moderate additional capacity for DER	**Low** Marginal or limits DER hosting capacity
Advances state energy and climate goals	Does the solution help **advance state goals**?	**High** Directly advances Maine's clean-energy and climate mandates	**Medium** Indirectly supports state goals	**Low** Neutral or misaligned with state goals

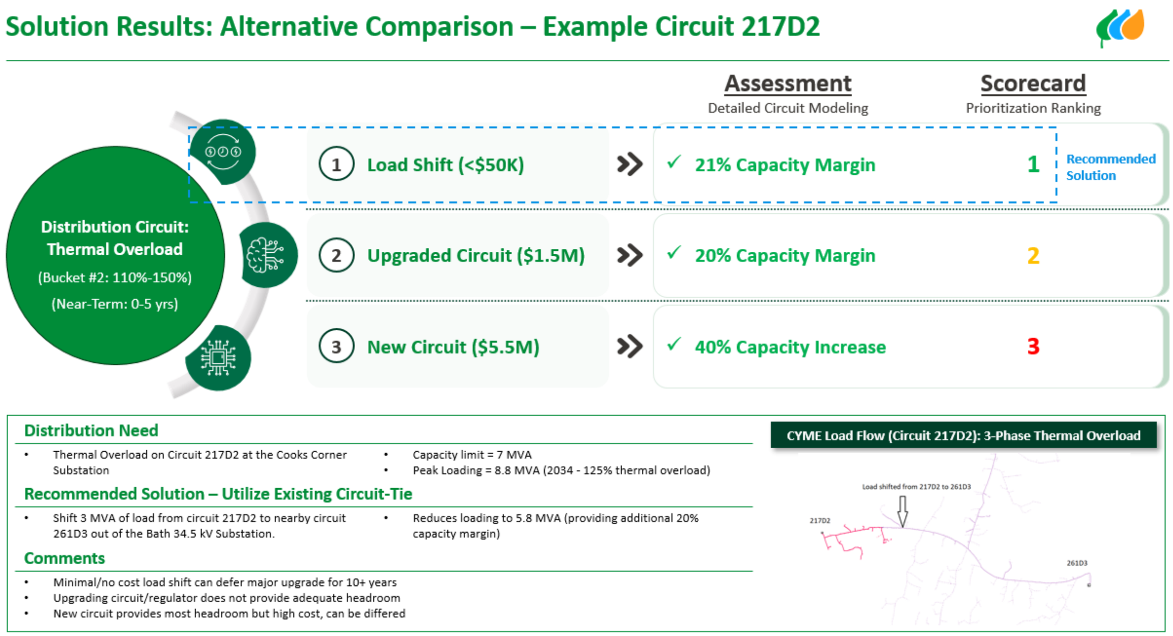
Using the methodology described within this section, CMP completed sixteen scorecards, ten for distribution system needs and six for transmission system needs, evaluating the scorecard template for each category. Please see Appendix E for the scorecards for each of the sixteen needs categories.

5.2. Case Studies

Case Study 1: Near-Term Distribution Circuit Thermal Overload – 125% Overload

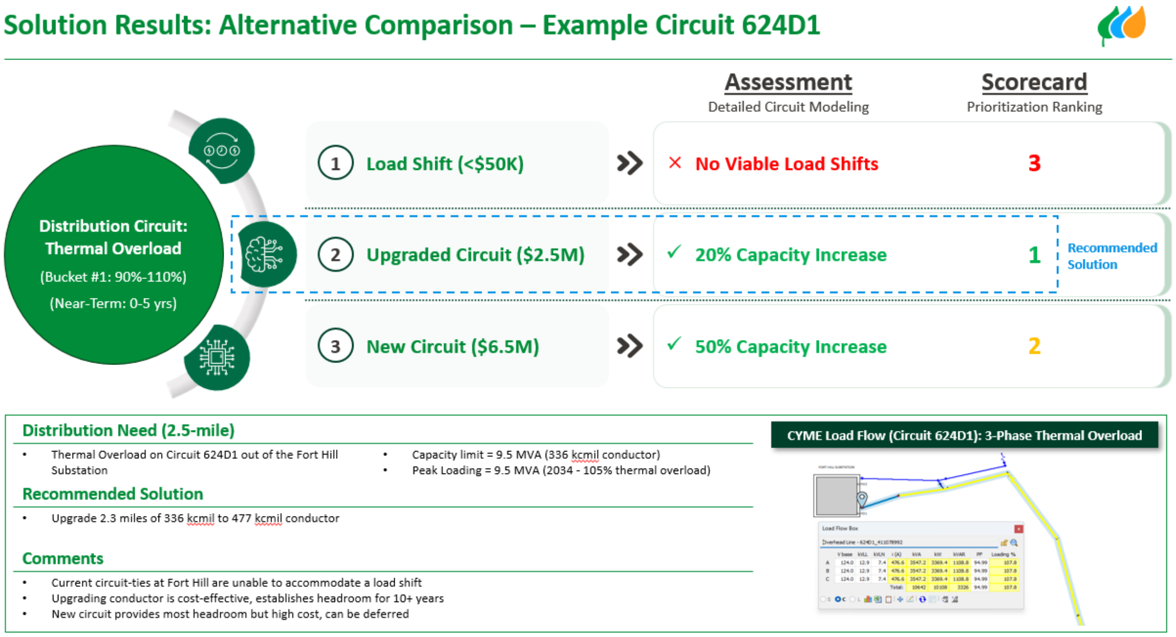
In an example of a moderate (125%) distribution circuit thermal overload identified in the near-term, CMP assessed a load shift, upgraded circuit, and new circuit. All three solutions were determined to be technically viable to alleviate the capacity constraint. In this case, CMP was able to identify an adjacent circuit with an existing tie and available capacity, so the recommended solution is a

low-cost load shift to shift 3 MVA of load to a nearby circuit. Utilizing the existing circuit-tie is the lowest cost solution and is the recommended approach.



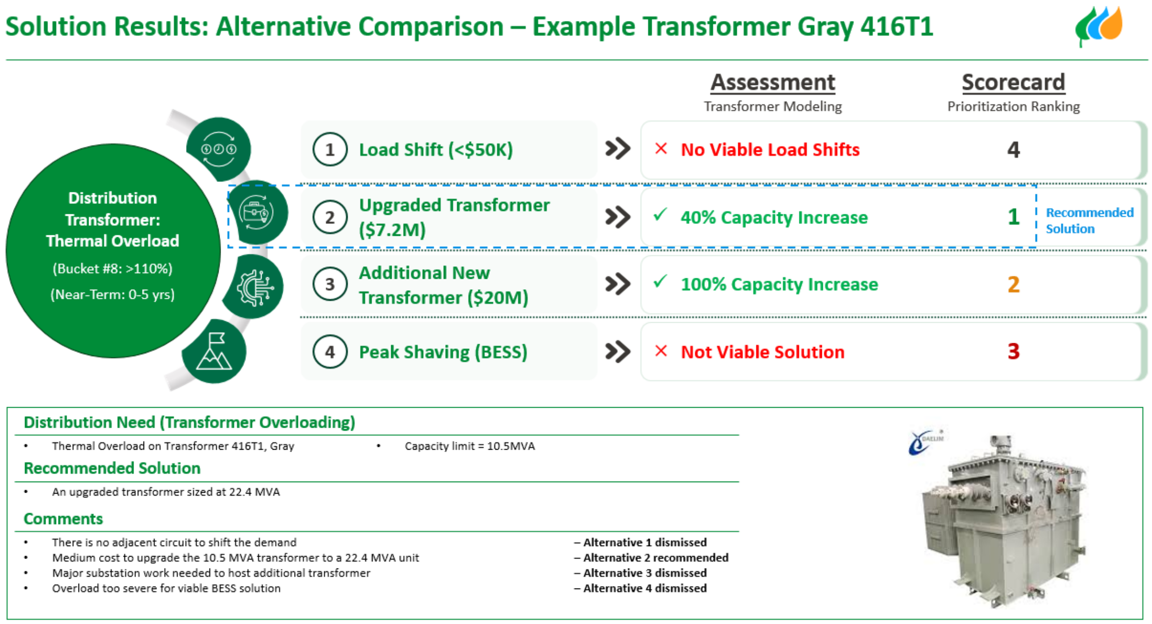
Case Study 2: Near-Term Distribution Circuit Thermal Overload: 105% Overload (Fort Hill Circuit 624D1)

In an example of a distribution circuit expecting about 105% overloading, the potential solutions assessed included a load shift, an upgraded circuit, a new circuit and peak shaving BESS. In this case, a load shift was not viable because there were no nearby circuits with available capacity. An upgraded circuit, new circuit and peak shaving BESS were potentially viable from a technical standpoint. That is why they were shortlisted in the Scorecard attached. The new circuit is not cost-effective to address the marginal thermal overload, so that option was dismissed. The costs to upgrade the circuit and install peak shaving BESS could be comparable depending on the size of BESS, but the peak shaving BESS provides less capacity and has shorter life expectancy. Since the upgraded circuit provides ample capacity margin at least cost, the upgraded circuit would be recommended.



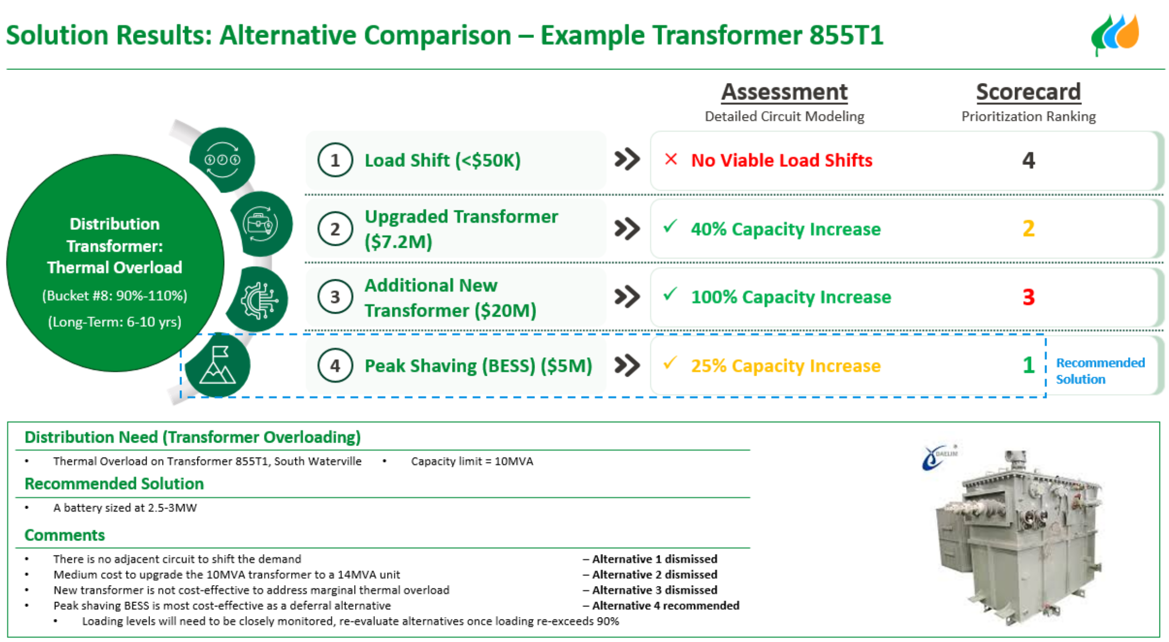
Case Study 3: Near-Term Distribution Transformer Thermal Overload 164% Overload (Gray 416T1)

In an example of a near-term distribution transformer thermal overload expecting severe (164%) overloading, Transformer 416T1, CMP assessed a load shift, upgraded transformer, new transformer and peak shaving BESS. The cost of a 22MVA distribution transformer upgrade to address the need is estimated at $7.2m, which is much less than the cost of adding a new transformer. CMP also considered peak shaving BESS and assessed hourly SCADA data for the transformer and determined that battery storage would not be viable or cost effective to address the size and duration of the thermal overload (18 hours). The recommended solution is to upgrade the transformer.



Case Study 4: Distribution Transformer Thermal Overload: 105% Overload (South Waterville)

In the case of a long-term distribution transformer thermal overload between 90-110%, Transformer 855T1, CMP assessed a load shift, upgraded transformer, new transformer and peak shaving BESS. In this case, a peak shaving BESS is effective to mitigate the less severe, long-term overload, and is the most cost-effective deferral alternative, and is the recommended solution. For more information, please see the pilot concept described in Section 7.5.



5.3. Solutions Evaluation Results

5.3.1. Solutions Evaluation Results - Distribution

While CMP already forecasts and evaluates needs on a 10-year horizon, solutions identification and evaluation traditionally focuses on a five-year timeframe. The IGP system modeling and solutions evaluation took a system-level view of capacity needs projected over the next ten years to explore longer-term strategies and broader planning perspectives.

The scorecard evaluations conducted for each category of need highlighted trade-offs between different types of traditional and alternative solutions. For example, battery storage may be less expensive than a circuit upgrade in some cases, but may provide lower capacity and have a shorter life expectancy relative to upgrading the capacity of a circuit. The benefits of an alternative flexibility solution such as load management, including existing infrastructure optimization, peak reduction, and emissions impact must be weighed against risks such as efficacy and reliability.

It is important to note that there is no single solution that is the “right answer” for all needs within a given category. The preferred solution is highly dependent on the characteristics of each element, including the level of overload (MW), the timing of the overload (e.g. a few hours a year vs. projected daily overload), cost of the traditional upgrade, influenced by factors such as the length of the circuit, and the cost and efficacy of potential alternatives (e.g. size of the battery needed to meet the need). A solution that is the best choice for one circuit may not be the recommended solution for another circuit in the same category.

The summary in Exhibit 5.5 presents recommended solutions for all near-term distribution system needs. The scorecard evaluation did not capture site-specific consideration for all needs, like circuit topography, adjacent circuits and substations, or substation bus configuration. To develop a solution set for the 166 near-term needs, CMP evaluated site-specific information for each need and applied lessons from the scorecard and site-specific criteria to develop cost estimates associated with implementing viable solutions for each need in the near-term. Using unit-based costs for near term needs, costs were extrapolated to long term needs to produce a cost range for solutions to all needs identified in the IGP. The costs to address the distribution capacity needs identified in the IGP are estimated at $790m - $1.3b, made up of near-term solutions to address the 166 distribution needs identified in the next 5 years ($575-950m) and long-term solutions to address 72 distribution needs identified in 6-10 years ($215-350m).

Exhibit 5.5: Distribution Solutions Results Summary

<table>
<tr><th rowspan="2"></th><th colspan="5">Near-Term: Thermal Overloads
(0-5 years)</th><th rowspan="2">Long-Term: Thermal Overloads
(6-10 years)</th></tr>
<tr><th colspan="3">Circuit</th><th colspan="2">*Transformer*</th></tr>
<tr><th>Potential Solutions</th><th>90-110%
(10 Needs)</th><th>110-150%
(43 Needs)</th><th>>150%
(28 Needs)</th><th>90-110%
(10 Needs)</th><th>>110%
(75 Needs)</th><th>Circuit & Transformer
(72 Needs)</th></tr>
<tr><td>Load Shift (incl. adding circuit tie)</td><td>1</td><td>9</td><td>6</td><td>6</td><td>20</td><td rowspan="8">Long-Term Solutions informed by near-term solution mix and scorecard summary results:

68 Low severity needs
• Most viable for Grid Utilization or New Technology solutions
• Likely opportunities to address needs & reduce cost with New Technology (*pilots are required to confirm viability)*

4 Mid & High severity needs
• Likely addressed by Grid Reinforcements (informed by near-term results and scorecards)</td></tr>
<tr><td>Circuit or Transformer upgrade</td><td>4</td><td>11</td><td>4</td><td>2</td><td>47</td></tr>
<tr><td>Regulator Upgrade</td><td>1</td><td>15</td><td>13</td><td>-</td><td>-</td></tr>
<tr><td>New Circuit</td><td>2</td><td>4</td><td>2</td><td>-</td><td>4</td></tr>
<tr><td>Substation Expansion</td><td>1</td><td>4</td><td>3</td><td>1</td><td>4</td></tr>
<tr><td>Peak Shaving Battery Storage Candidate</td><td>-</td><td>-</td><td>-</td><td>1</td><td>-</td></tr>
<tr><td>Load Management Candidate</td><td>1</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Total Needs Addressed</td><td>10</td><td>43</td><td>28</td><td>10</td><td>75</td></tr>
<tr><td></td><td colspan="5">**$575M - $950M** *(unit-based estimate)*</td><td>**$215M - $350M** *(unit-based estimate)*</td></tr>
</table>

Upon evaluation of ongoing projects, CMP identified 14 ongoing projects at varying levels of approval that can solve 26 of the identified IGP needs, leaving 140 needs to be addressed. To address those needs, CMP identified 118 solutions[30], coordinating across needs to identify solutions that address multiple needs wherever possible. For example, three transformer overloads at West Waterville 865T1, 865T2 and Oakland 839T1 are solved by one project to upgrade 865T2, create a new circuit, and use the new circuit to offload 855T2, and 839T1.

In the near-term (0-5 years), the focus is on addressing pressing constraints with the deployment of proven mitigation measures, while also laying the groundwork for future innovation through investments in smart technologies, including advanced monitoring, data collection, and automation infrastructure. The solutions prioritized to meet grid needs in the next five years are:

- New and upgraded substations and circuits to meet immediate needs with additional capacity to support growing demand from electrification and accommodate additional DERs
- Regulator upgrades to address situations where regulators are overloaded
- Lower cost solutions such as load shift and circuit tie, where excess capacity is available on a nearby circuit
- Pilot peak shaving battery storage to address a near-term identified low severity capacity need
- Load management pilot to address a near-term low severity capacity need

[30] The cost range shown in Exhibit 5.5 reflects the 118 solutions to address 166 near-term distribution capacity needs.

During this timeframe, CMP will not only focus on addressing immediate system needs, but also on actively engaging with stakeholders to explore and validate emerging technologies. For example, while load management may not be a viable solution in the near-term due to uncertainties regarding efficacy and reliability, this solution could be piloted on circuits projected to overload in later years, in order to test load management as a peak mitigation strategy. This collaborative approach is essential to ensure that innovative solutions are tested in real-world conditions and refined through shared learning.

In the longer term (6-10 years), the deployment of ADMS and DERMS features could help enable flexible solutions such as coordination and optimization of DERs and customer demand. In addition, many of today's emerging technologies may have advanced in terms of technical maturity, commercial viability, and supply chain readiness. As these solutions become more scalable and cost-effective, they may play a more prominent role in grid development. These innovative technologies will complement conventional infrastructure reinforcements, contributing to a more flexible, resilient, and efficient electricity system. This phase will focus on strategic deployment, leveraging the insights and pilot results from the first five years to guide broader implementation.

5.3.2. Solutions Evaluation Results -Transmission

In line with the modelling methodologies set out in Chapter 4 and the needs categorization approach outlined in Section 5.1.1, six categories were designed to represent the transmission system needs identified through the IGP exercise, as described in Section 5.1.3. CMP applied the models developed in Section 3 to the transmission system using the 18 scenarios also described in Section 3, and using the methodology for contingencies and the required modeling criteria described in Section 4.2.2, which resulted in the needs identified in Exhibit 5.2.

Once needs were identified, CMP developed scorecards for each category of needs to evaluate solutions alternatives. The table below illustrates the range of potential solutions for each category of need. Similar to the distribution system, lower severity needs are more likely to be addressed through solutions like grid enhancing technologies, while more severe needs likely must be addressed through infrastructure upgrades; reliability and asset condition are key considerations in transmission planning. The projects in the forecast are based on similar modeling assumptions and are anticipated to address the majority of needs identified in the grid plan. For context, the forecasted transmission investment for the next 5 years is $1.55B. Exhibits 5.6 and 5.7 summarize potential solutions to address transmission thermal overloads and voltage violations respectively and illustrate the suitability of potential solutions for addressing varying levels of severity.

Exhibit 5.6: Transmission Solutions for Thermal Overloads

Potential Solutions	Near-Term: Thermal Overloads (0-5 years)			Long-Term: Thermal Overloads (6-10 years)			
	90-110%	110-150%	>150%	90-110%	110-150%	>150%	Commentary
Transmission Line Upgrade	√	√		√	√		Replacing the existing conductor with more thermal capacity is a solution for low to mid overloads.
New Transmission Line		√	√		√	√	Construction of a new line may include new buses, protection and control devices, for mid to severe overloads.
Transformer Upgrade	√	√		√	√		Replacing the existing transformer with more thermal capacity is a solution for minor to mid overloads.
Additional Transformer		√	√		√	√	Add a new transformer to operate in parallel, typically a solution for mid to severe loading.
Peak Shaving Battery Storage	√			√			Peak shaving is generally a viable option for minor overloads when the duration of overload is short (4-8 hours).
Advanced Conductor (GET)		√	√		√	√	Advanced conductors utilize existing rights-of-way to expand capacity beyond traditional reconductoring.
Dynamic Line Ratings (GET)	√	√		√	√		DLR optimize current carrying capacity and can allow for 5-25% more capacity than static line ratings for low-mid overloads.

While some of the solutions that address thermal overloads may also address voltage violations in some cases, transmission voltage violations may also need specific solutions to maintain voltage stability over long distances. While Statcom and synchronous condensers are higher cost than traditional capacitor banks, they are increasingly becoming preferred solutions for addressing voltage violations given their ability to provide dynamic voltage support.

Exhibit 5.7: Transmission Solutions for Voltage Violations

Potential Solutions	Near-Term: Voltage Violation (0-5 years)			Long-Term: Voltage Violation (6-10 years)			
	<0.9 p.u.	0.8 p.u. - 0.9p.u.	<0.8 p.u.	<0.9 p.u.	0.8 p.u. - 0.9p.u.	<0.8 p.u.	Commentary
Capacitor Banks	√			√			Low upfront cost, but does not provide dynamic support
Static Compensation (Statcom)		√	√		√	√	Higher upfront cost; can provide dynamic voltage stabilities, but not frequency stability
Synchronous Condenser			√			√	Higher upfront cost; can provide dynamic voltage support and enhances system stability

CMP is actively exploring the feasibility of piloting and deploying grid enhancement technologies (GET) to mitigate thermal capacity constraints. These tools include advanced conductors (high-temperature, low-sag), dynamic line rating, battery energy storage, and transformer retrofitting; along with established solutions such as conductor upgrades, new circuits, new substation (with optimized topologies), transformer upgrades and/or adding an additional transformer operating in parallel.

Given the high voltage levels and large volume of power flows on transmission lines, it has been identified that the minor overloading category (where thermal violations are less than 110%) may represent the "low-hanging fruit." In these cases, GET can sometimes be competitive and deliver tangible benefits.

A solid and reliable transmission infrastructure remains critical to safeguarding a secure energy supply for customers during times of need, such as severe storms. The extent and magnitude of demand growth and projected thermal overloads will require infrastructure upgrades to expand capacity. As their name suggests, GETs can enhance the capacity and capabilities of the existing infrastructure, especially in the short-term, given that they can be implemented faster than a transmission project can be built. For DER-driven network needs, a coordinated approach should be adopted. CMP Transmission Planning, Interconnections, and Operations will work closely with DER developers to explore early opportunities for piloting and applying new technologies—such as Active Network Management (ANM), Microgrid with Energy Storage, Distributed Energy Resource Management (DERM)—to provide economical, timely, and reliable access to the network wherever possible, and without adversely impacting the ratepayer's affordability.

While the current scorecard design reflects a strong emphasis on policy alignment and acknowledges that the IGP is not intended as a platform for presenting individual projects or seeking regulatory approval, it is important to note that electricity network planning is a systematic exercise, inherently complex and evolving. They require consideration of multiple factors, including asset conditions, geographic footprint, climate resilience, and future proofing. In addition, external dynamics such as raw material market prices, supply chain competitiveness, and technological advancements can significantly influence the recommended options and their design.

In transmission planning, CMP identified that under winter conditions, a specific line section was overloaded in 39 different N-1 contingency scenarios. In these cases, the line exceeded its long-term emergency rating by 104% to 267%. The contingencies causing these overloads include loss of a transformer, transmission line, breaker (including breaker failure), capacitor bank, or generator.

Because these events occur across multiple locations and involve varying overload levels, the issue cannot be resolved by addressing a single contingency or by upgrading the line alone. Instead, a combined approach is required: mitigating the most severe contingencies—either by eliminating them or adding a new or parallel line in the area—along with upgrading the existing line.

Upgrading the line to industry-standard sizing would reduce overloads to about 155%. However, further topology optimization is necessary, which includes constructing a new 115 kV substation and adding a parallel 115 kV line near the upgraded section. This type of multi-step solution is typical for CMP when addressing thermal issues on the transmission system.

5.3.3. Solutions Evaluation Results – Key Takeaways

The scorecard evaluation was a valuable exercise in considering how additional impacts may be considered in the project planning and solution evaluation process. As a qualitative tool, the scorecard is designed to complement and enhance, not replace, the existing planning, project prioritization, and NWA evaluation processes. CMP found value in exploring how non-monetary impacts that have historically not been directly captured in quantitative project prioritization analyses, such as EEEJ metrics and policy alignment, should be weighed relative to traditional considerations like solution cost and efficacy.

Key takeaways from the solutions evaluation include:

- The scorecard exercise provided valuable insights into how different solutions align with network needs. NWAs can be most effective when appropriate underlying people, processes, and technology enable a non-wires solution for addressing minor network violations (around 110%) subject to detailed BCA analysis and supply-chain engagement.
- Barriers to alternative solutions may limit the role they can play in the near-term, including regulatory, cost and operational technology barriers:
  - Regulatory barriers: Technology ownership; roles and responsibilities among third parties, utilities, EMT; cost recovery and cost allocation; incentive schemes to align technology adoption with customer and system benefits.
  - Cost barriers: The unit cost of alternative technologies such as battery storage is often higher than traditional circuit upgrades
  - Operational barriers: Technologies and systems are not in place to manage harmonic injection into the grid, active and reactive power control software interface and cyber security
- While various NWAs hold significant potential—particularly in enabling demand flexibility and DER integration using existing infrastructure—their successful deployment depends on more than just technical feasibility. These solutions require detailed asset condition assessment, additional monitoring, communication and control infrastructure with proper cyber security consideration, and proper planning well in advance to ensure effective implementation and operation.
- Certain NWA technologies may require a supporting mechanism and/or innovation incentive to kick start. These include the need for additional technical support, longer lead times, and uncertain cost recovery mechanisms.
- Along with the barriers we identified in this IGP, mixed industry experience and feedback from various publicly available trial projects have resulted in inconclusive comparisons in scorecard. This is largely because such evaluations often require detailed, project-specific data and real-time cost assessments to draw meaningful conclusions- a task for CMP's internal BCA and Investment Planning processes.

Given these constraints, and the urgency of addressing immediate network needs, established network mitigation methods—such as traditional line and/or transformer upgrades—are often among the most cost-effective and reliable solutions in terms of both deployment timescale and operational efficacy.

In parallel with efforts to address the urgent system needs to improve resiliency, CMP has proactively pursued opportunities to advance grid modernization. Working collaboratively with stakeholders, CMP has identified specific circuits and geographic areas suitable for piloting grid-enhancing solutions such as dynamic line ratings and battery load shaving. These initiatives reflect CMP's ongoing commitment to innovation and readiness to implement practical, scalable technologies that support a smarter, more resilient grid.

An overview of cost-effective near-term and longer-term grid investments and operations needed to achieve the IGP priorities is provided below.

Exhibit 5.8: Overview of Near-term and Long-term Solutions to Achieve IGP Priorities

IGP Priorities	Near-term (2026-2030)	Long-term (2031-2035)
Reliability and Resilience	• **Alleviate 166 network capacity constraints identified in the IGP evaluation and prepare for an additional ~500 MW of electricity demand** • **Harden substations and circuits to address asset condition** • **Increase backup circuit-ties to reduce the impact of outages** • Continue deploying **Distribution Automation (SCADA devices) to improve visibility and remote-control capabilities** • Complete rollout of **Distribution Automation to achieve visibility and remote-control capabilities across 100% of circuits by 2031** • **Pilot battery storage for reliability and contingency backup use cases**	• **Alleviate 72 network capacity constraints and prepare for an additional ~600 MW of electricity demand** • **Create sufficient network hosting capacity to enable the connection of up to 1.6 GW of low-carbon generation by 2035** • **Continue to harden substations and circuits to address asset condition** • **Continue to increase backup circuit-ties to reduce the impact of outages** • Explore opportunities for **battery storage deployments in cost effective use cases**
Improve Data Quality, Integrity	• **Integrate AMI and SCADA data** into forecasting and system planning • Implement advanced forecasting and system planning tools to **enable time series analysis** • **Improve mapping of the distribution system** (Grid Model Enhancement Project) • **Enhance hosting capacity** maps	• **Enhanced system modeling** capabilities using **time series analysis** enables more automated and efficient evaluation of solutions • Enable real-time data, improved interoperability and enhanced capabilities in analytics, DER management and control
Promote flexible management of consumers' resources	• Deploy ADMS features to **lay the foundation for integration and utilization of DERs**, enabling load flexibility • Coordinate with EMT on impacts of **customer flexibility programs**	• **Flexible load management and DER optimization** play a role in proactively mitigating peak demand, enabled by DERMS • **Enhanced DERMS** features enable new solutions and use cases • Scale deployment of smart grid technologies, such as GETs

5.4. Connection Between Scorecard and Key Planning Processes

The scorecard required in the IGP serves as an early-stage tool to evaluate potential solutions for identified system needs. This scorecard provides a conceptual framework for comparing both traditional infrastructure upgrades and NWAs, offering insight into their relative viability and alignment with broader policy objectives. Its connection with the internal utility capital planning process, the NWA process, and the impact of EMT programs is discussed further below.

Internal Utility Capital Planning

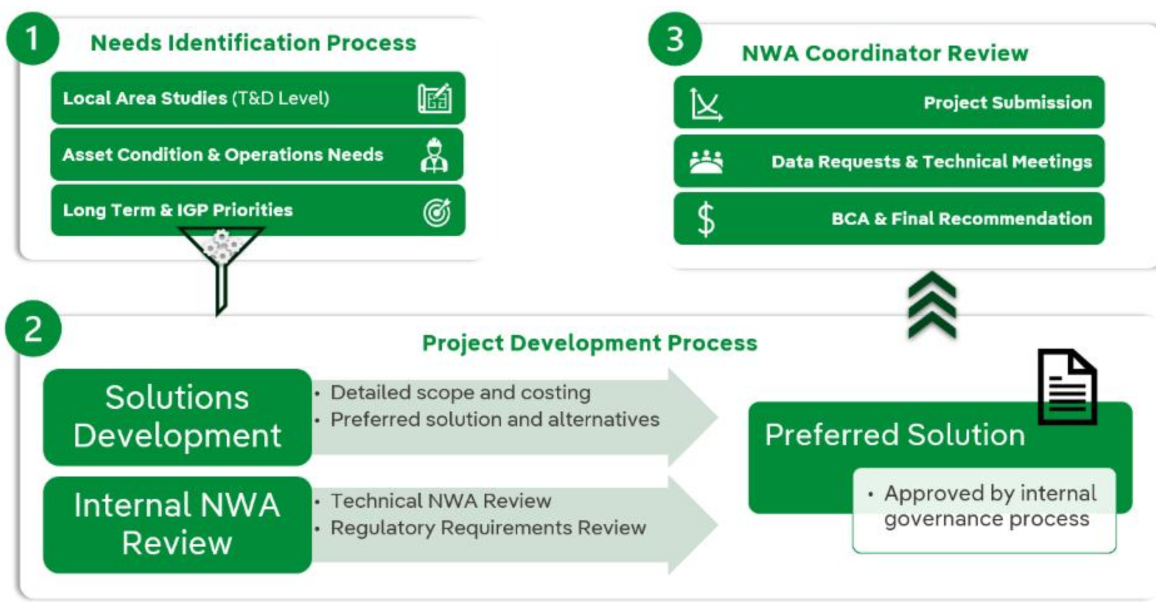
CMP's internal capital planning process incorporates both conventional grid investments and NWAs as potential solutions to address system needs. The scorecard complements this process by providing a structured, qualitative assessment of solution options before projects reach maturity. Internal planning relies on the ISO-NE CELT forecast, which reflects state policy goals and anticipated load growth, like the scorecard. Both processes consider efficacy and feasibility, ensuring that solutions align with reliability requirements and long-term objectives.

NWA and Coordination with Efficiency Maine Trust

The NWA process, including coordination with EMT, is grounded in formal benefit-cost analysis (BCA). While the scorecard does not replace the BCA, it informs early-stage discussions by highlighting conceptual opportunities for NWAs that may warrant further evaluation by the Non-Wires Alternatives Coordinator (NWAC) and EMT. Because the scorecard operates at a higher level than the BCA, it is inherently less specific and applied before projects are fully developed. This approach allows CMP to identify needs that may be suitable for NWAs, particularly those of lower severity or with medium- to long-term timelines, prior to formal review.

Impact of Trust Programs and Other Initiatives

Programs administered by EMT, as well as federal initiatives aimed at reducing ratepayer impacts, could influence the scorecard results. For example, successful implementation of energy efficiency or demand reduction programs may lower projected system needs, shifting projects into categories where NWAs become more viable. The scorecard reflects these dynamics by signaling the appropriate prioritization of solutions.



5.5. NWA Barriers and Solutions

CMP recognizes that effective future grid planning requires identifying barriers within the current NWA process and advancing solutions that facilitate broader deployment of NWAs, alongside traditional wires investments.

A principal barrier to NWA adoption in Maine is the absence of a standardized benefit-cost analysis (BCA) framework for assessing the cost-effectiveness of NWA projects. A consistent and transparent BCA framework is essential to determine whether proposed NWA investments are prudent and deliver lifecycle value relative to traditional infrastructure solutions.

CMP also sees opportunities to improve internal processes to better identify, evaluate, and advance projects that are well-suited for NWAs. A streamlined review pathway, clearer terminology, and simplified project categorization would reduce complexity and promote more efficient decision-making. CMP intends to work collaboratively with regulators and stakeholders to refine these processes within existing regulatory and legislative parameters.

CMP envisions reducing barriers to successful NWA deployment through several strategies: (a) leveraging more granular data and advanced planning tools to improve forecasting and project targeting; (b) standardizing BCA methodologies to promote consistency and transparency in evaluating NWA solutions; and (c) piloting new technologies and approaches, including the transition to time-series analysis, to enhance planning accuracy and flexibility.

In addition, the legal and regulatory framework governing utility ownership and operation of energy storage assets warrants clarification. Clear rules for utility ownership would provide needed certainty to incorporate storage resources into standard planning processes, enabling these assets to function as cost-effective grid solutions.

Through these efforts, CMP aims to establish a more efficient and transparent process that promotes the adoption of NWAs where they offer the greatest value, while maintaining reliability and affordability for customers.

5.6. Milestone 3 Stakeholder Engagement

Milestone 3 focused on identifying and evaluating solutions for the needs revealed in CMP's earlier IGP phases. Stakeholders provided feedback on solution strategies, prioritization, and broader planning considerations.

Addressing Emerging Load and Generation Challenges

- Stakeholders emphasized growing concerns about mid-day solar surplus and winter peak loads. They urged CMP to explore solutions such as battery storage to absorb excess solar and manage winter demand, as well as further involvement with DOER and ISO-NE, which have influence over supply. (CMP acknowledges these challenges throughout the IGP, and provide potential systems, technology, and infrastructure solutions in Sections 6 and 7, but which do not address the supply concerns.)

Non-Wires Alternatives and Technology Enablement

- Efficiency Maine Trust supported inclusion of non-wires solutions and suggested CMP commit to working with EMT on geotargeted load reductions before circuits reach critical thresholds, and to make associated billing system improvements. (CMP incorporates non-wires solutions in Section 6, and has included a potential geotargeting program in Section 7.)

- Stakeholders requested clarity on terms like DERMS and encouraged CMP to define enabling technologies such as ADMS and flexible interconnections. (CMP has defined and provided information about these technologies in Sections 6 and 7.)

Practical Considerations for Solutions

- DOER sought clarification on whether electrification readiness scoring is numerical or subjective. (CMP has provided an explanation of scoring metrics in Section 6.1.3.)
- NGOs recommended tying alternatives directly to scorecards, linking solutions to enabling technologies, and clarifying how severity and term influence solution selection. They also requested inclusion of need counts per category in presentation materials. (CMP has incorporated all of these recommendations in the report at Sections 6 and 7.)

Reliability and Resiliency Integration

Stakeholders stressed that reliability and resiliency should be considered alongside capacity needs. (CMP has included a discussion of the incorporation of reliability and resiliency needs in Section 5, and discusses enabling technologies such as automation, centralized control, and advanced forecasting as foundational for deploying advanced solutions like DERMS and battery storage for reliability and resiliency, as well as for capacity needs.)

06. Technology, Integration, Systems Investments and Pilot Projects

This section describes the technologies, integration, and systems investments needed to support IGP priorities and the cost-effective achievement of the state's climate and clean energy goals. It includes a roadmap for planned improvements, systems investments, necessary integrations and pilot projects over the next ten years.

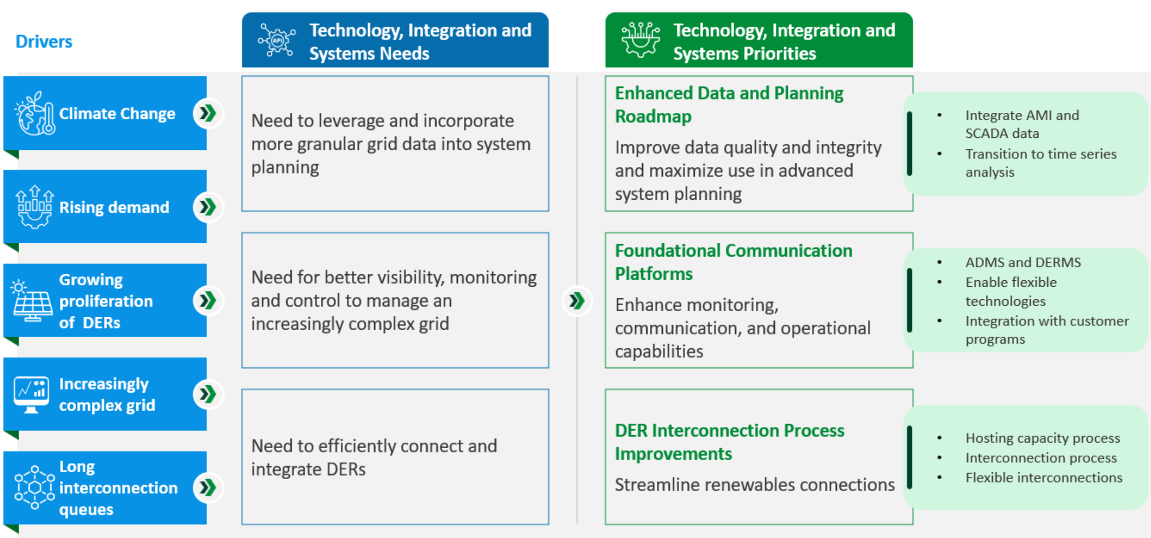
Key Take-Aways:

- Foundational infrastructure investments are needed to support more advanced technologies.
- Foundational platform investments in ADMS and DERMS are needed to help enable load and resource flexibility services that can more dynamically respond to grid constraints in specific locations.
- The CMP Energy Control Center could leverage the full benefits of SCADA Distribution Automation, DER Management and AMI infrastructure with enhanced control systems such as ADMS and DERMS

6. Technology, Integration, Systems Investments and Pilot Projects

As the distribution network continues to evolve with the proliferation of DERs and rising demand from transportation and building electrification, the increasing complexity of dynamic loads and two-way power flows are creating operational challenges and opportunities. These drivers are creating a need to leverage and incorporate more granular grid data into system planning, as well as a need for better visibility, monitoring and control to manage and optimize an increasingly complex grid. In addition, continued growth in DERs and long interconnection queues are creating a need for more efficient processes and tools to connect and integrate DERs. Addressing these needs requires systems investments, integration between systems, as well as pilots to test and scale new technologies and capabilities. CMP's plan to address technology and data needs is focused on the following priorities:

- Enhanced data and planning roadmap to improve data quality and integrity and maximize use in advanced system planning
- Foundational communication platforms to enhance monitoring, communication, and operational capabilities
- DER interconnection process improvements to streamline renewables connections



CMP has implemented some of the foundational technologies and capabilities to achieve a modern and flexible grid, including AMI, GIS, EMS, and the rollout of Distribution Automation technologies. See section 2.1.2 for a discussion of the Company's AMI system and technologies that enable distribution automation, monitoring and control.

The EPE Roadmap[31] filed in the Grid Modernization Case (2021-00039) identified gaps between the current state of the distribution system and the desired future state needed to address challenges presented by climate change, electrification and increasing integration of renewables and DERs. CMP has made progress adopting many of the short-term recommendations, and the following section includes plans for addressing medium- to long-term recommendations. Progress on recommendations from the EPE Roadmap include:

- Continuing reliability improvement: CMP began a distribution automation program in 2023, which included installing 452 three-phase devices and 27 single-phase devices between 2023-2025. CMP plans to complete the installation of distribution automation devices (~2,800 devices) across its entire service territory by 2031.
- Hosting Capacity: CMP completed EPE's recommendation to expand its hosting capacity maps from a pilot on two substations to the entire distribution network. CMP also developed and published a system-wide Solar PV Hosting Capacity map designed to indicate areas of the system where headroom likely exists today.
- Leveraging AMI data: CMP is actively working to integrate AMI data into CYME to support more accurate load allocation and power flow studies.

6.1. Enhanced Data and Planning Roadmap

The rate at which demand and DERs are growing is adding complexity to demand forecasting and system planning and has significant implications for the timing of when system capacity is needed in a given area. As the energy landscape evolves—with increasing electrification, distributed energy resources (DERs), and dynamic load profiles—traditional planning methods based on static snapshots are no longer sufficient on their own. While still in the relatively early stages of adoption, a shift to time series analysis will enable CMP to account for the granular effects of DER and load profiles on an increasingly complex grid and evaluate opportunities to improve grid utilization.

Improving data quality and integrity is foundational to leveraging more granular data in distribution system planning. CMP has a number of initiatives planned and underway to improve data quality and integrity, such as the Grid Model Enhancement Project (GMEP) to enhance distribution system mapping and an enterprise cloud solution to enable integrated data across systems. In alignment with the IGP priorities established by the MPUC and the recommendations in the EPE CMP Roadmap Report[1], CMP developed a roadmap to enhance data utilization, integrate time-series analysis, and modernize planning practices:

[31] EPE. "Roadmap for CMP's Distribution System." Mar 15, 2022. Docket No. 2021-00039 - Attachment B.

Exhibit 6.1: Enhanced Data and Planning Roadmap

	Short-term (<2 years) *Infrastructure, Coverage & Deployment*	Mid-term (2-5 years) *Improved Data Availability and Quality*	Long-term (>5 years) *Enhanced Modelling and Network Operation*
Improved Data Quality	• GMEP Survey Completion to improve physical-cyber representation • GIS survey complete to improve accuracy • Integrated data strategy (CYME Server)	• Complete rollout of SCADA devices on all circuits • AMI data collection improvements • Interfaces with multiple applications	• Continue with communications equipment upgrades, integration of data, and advanced planning and modeling
Advanced Forecasting	• Adopt new tool to support multiple simulation scenarios (ITRON's MetrixDx) • Integrate AMI and SCADA data into MetrixDx platform	• Update DER, EV and heat pump load profiles based on latest usage trends • Evaluate expanded scenario modeling	• Update DER, EV and heat pump load profiles based on latest usage trends • Iterate and enhance scenario modeling
Advanced System Planning	• Integrate AMI and SCADA data with distribution planning software (CYME) • Simulation Software enhancement	• Shift planning standards and simulation methods to time-series analysis • Enhance CYME software and forecast capability into control room	• Greater automation to streamline data extraction, validation and processing
Key Capabilities Enabled	• Advanced load forecasting produces hourly load forecasts for every circuit • Parallel processing for time-series load profile analysis	• Advanced planning time series analysis (8760-hour modeling and scenario simulation)	• Improved efficiency and scalability in time-series modeling • Enhanced system operation

CMP's strategy to improve data quality and integrity and enhance system planning includes:

AMI Integration and Modernization

CMP is actively working to integrate AMI and SCADA data into CYME to support more accurate load allocation and power flow studies. This integration will enable the development of detailed load profiles and unlock capabilities for time-series simulations. CMP is also establishing data governance protocols to ensure ongoing data integrity and consistency across systems.

Improve Mapping of the Distribution System

The Grid Model Enhancement Project (GMEP) includes a comprehensive field survey of CMP's distribution system, reconciling historical records with field collected data. This initiative will improve physical-cyber representation of assets, model accuracy, and support unbalanced power flow studies, thereby enhancing the fidelity of system simulations. Accurate data and model quality are also foundational to advanced system operations and utilization of ADMS. GMEP is expected to be completed by Q1 2026 and includes establishing a data governance process to help ensure that data quality is maintained.

Integrated Data Strategy

CYME Server (or an alternative cloud solution) is needed to act as a bridge between various enterprise systems, such as GIS, SCADA, AMI, and the CYME power engineering analysis software. A complete Service Oriented Architecture (SOA) solution offers real-time network analysis with powerful CYME simulation engines and can be seamlessly embedded into enterprise applications. A powerful integration solution to streamline and enhance the accuracy of electrical distribution network modeling, it will enable parallel processing for time-series load profile analysis.

6.1.1. Shift to Time-Series Planning and Advanced Forecasting

CMP's forecasting capabilities are undergoing a significant transformation to meet the evolving demands of grid planning. This evolution is driven by the need for greater granularity, flexibility, and responsiveness to emerging technologies and policy priorities. CMP developed a roadmap (see section 7.1) for transitioning from traditional static-point forecasting to dynamic, time-series modeling that supports hourly analysis across the distribution system over the next 5 years.

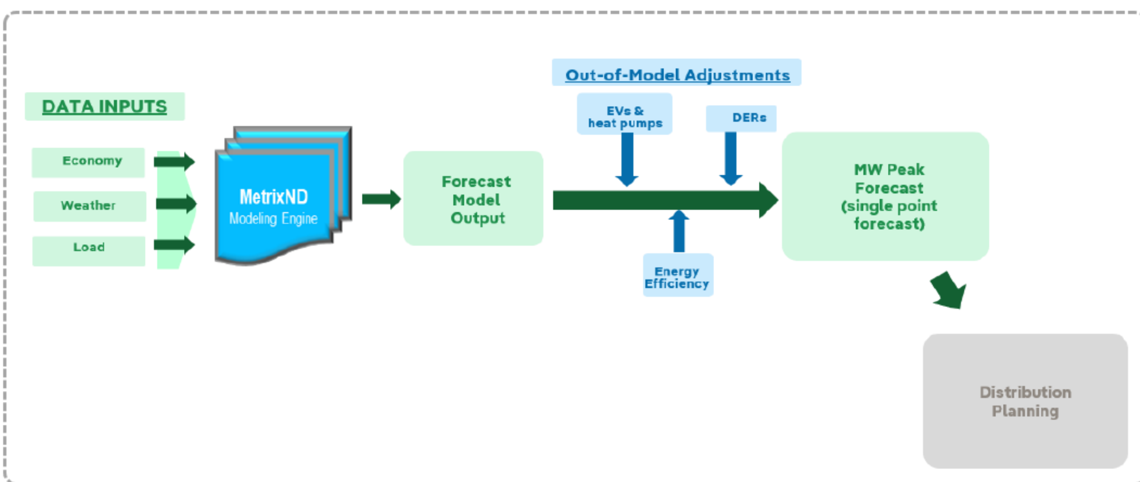
Current Forecasting Process

Currently, CMP's electric peak forecasting relies on econometric models that produce summer and winter single-point forecasts of system peaks. As shown in Exhibit 6.2 below, these forecasts are based on a set of underlying exogenous variables representing weather conditions, economic indicators, and seasonal trends. Once generated, these single-point peak forecasts are disaggregated across CMP's service centers and distribution substations using bottom-up assumptions for organic growth, EV adoption, and heat pump conversions.

While this approach provided system planners with sufficient information to prioritize infrastructure investments, it lacks the resolution needed to capture the dynamic impacts of DERs, EVs, heat pumps, and climate variability. Increasing adoption of DERs, EVs and heat pumps is prompting a need for more granular assessment of the effects of these technologies on specific circuits, such as the ability to simulate hourly load variations.

Exhibit 6.2: Current CMP Peak Forecast Process

This diagram outlines CMP's existing methodology for generating single point summer and winter peak forecasts, including the use of econometric models and substation-level disaggregation.



Future Forecasting Process – Enabling Advancing Forecasting Capabilities

To address these limitations, CMP plans to invest in a new generation of forecasting tools and infrastructure. The proposed Advanced Load Forecasting approach will enable time-series analysis at the distribution circuit level, supporting full 8760-hour modeling and scenario simulation.

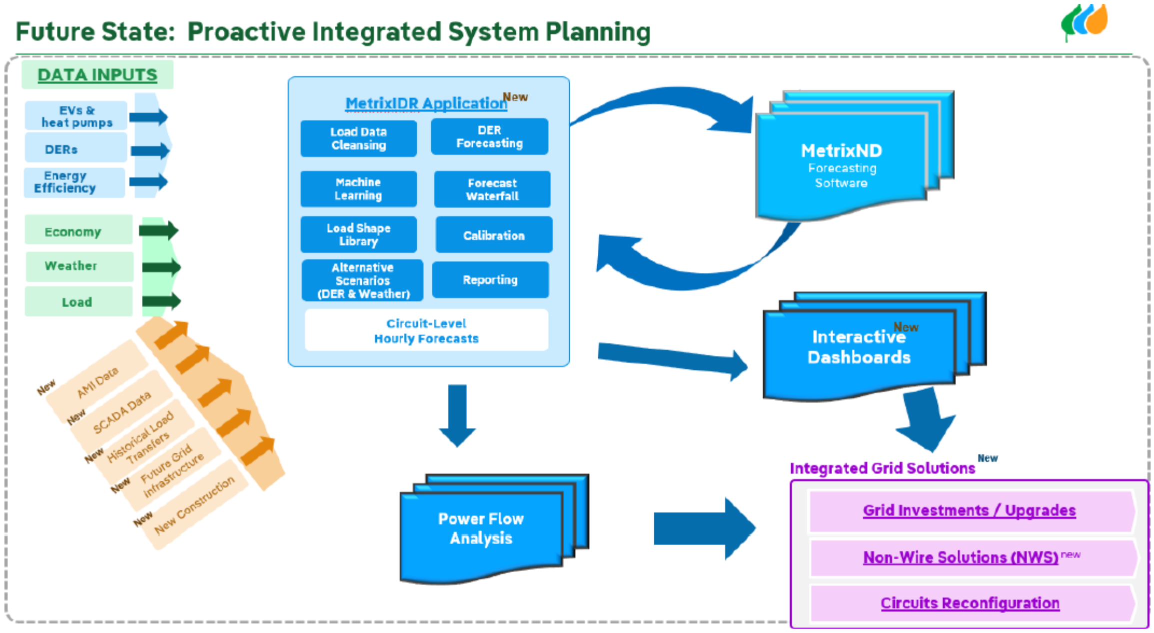
This future process will leverage high-resolution data from AMI and SCADA, as well as DER adoption metrics, electrification trends, and customer segmentation. These data streams will feed into a forecasting platform capable of producing hourly load forecasts for every distribution circuit, which can then be aggregated to the system level.

CMP's Advanced Load Forecasting initiative is designed to improve the granularity of forecasts in terms of time, location, and technology impact. It will allow planners to assess adoption and load impacts from EVs, electric heat pumps, and solar generation. The platform will also simulate the effects of rate design, managed charging programs, and flexible load technologies—providing insights into how these variables shape load profiles and infrastructure needs.

To implement this vision, CMP proposes integrating ITRON's MetrixDx software with the existing MetrixND platform that is currently used for load forecasting. MetrixDx ingests AMI and SCADA data and supports multiple simulation scenarios for each circuit, including varying levels of DER, EV, and heat pump adoption. The tool also includes interactive dashboards for visualizing forecast outputs and scenario comparisons.

Exhibit 6.3: Example Advanced Load Forecasting Framework

This graphic shows the architecture of a potential planned forecasting tool, highlighting the integration of AMI, SCADA, DER, and customer data to enable hourly, circuit-level scenario modeling.



This example advanced load forecasting approach could enable more robust time-series (i.e., hourly) analysis to better inform system planning efforts, including identifying opportunities for potential NWAs such as demand response or battery storage based on the timing and duration of projected overloads. It could also address several of the Commission's IGP priorities, including the advancement of time-series planning models and improved forecasting of EV load, DER adoption, and climate parameters.

The next IGP will cover the period from 2030 to 2040 and therefore will be critical to informing the investments needed to achieve Maine's goal of 100% clean electricity by 2040. Investments in advanced load forecasting over the next five years are critical to enabling time-series analysis and improved granularity for the next IGP. Future iterations will also evaluate expanded scenario modeling, such as those used in the Maine Pathways to 2040 study, to reflect evolving technologies and customer behaviors. CMP will continue to engage stakeholders and refine its forecasting tools to ensure that grid planning remains transparent, data-driven, and responsive to Maine's energy transition.

CMP is transitioning from traditional static-point forecasting (e.g. summer and winter peak) to dynamic, time-series forecasting and modeling that supports hourly analysis across the full year (8760 hours). This transition to more dynamic and complex analysis requires new tools and capabilities and is dependent on integrating hourly data from AMI and SCADA.

CMP is transitioning toward time-series analysis using CYME's "Steady State Analysis with Load Profiles" module. This approach allows for dynamic modeling of load and generation profiles over 8,760 hours annually, providing a more dynamic assessment of system behavior. CMP plans to pilot time-series studies on circuits with high DER penetration and evaluate flexible mitigation strategies such as energy storage and demand response. Additionally, CMP is moving toward time-series load forecasting by leveraging AMI, SCADA and customer segmentation data.

6.2. Enabling Load Flexibility

Section 5 provided an overview of the potential solutions to reliably serve rising demand and integrate growth in DERs, including grid upgrades to expand system capacity and alternative solutions like battery storage, grid enhancing technologies, load management and peak shaving. Realizing the potential of these solutions to optimize grid capacity utilization, such as load management, to defer or avoid grid constraints requires:

1. Deployment of grid and customer **technologies** necessary to enable load flexibility, such as batteries, smart thermostats, and smart EV chargers
2. Foundational **systems investments** in network management platforms such as ADMS and DERMS
3. **Integration** with customer programs and/or rate design to manage or incentivize optimal usage

6.2.1. Available and emerging technologies necessary to enable load flexibility

Available grid technologies that can provide and enhance flexibility include battery storage and grid enhancing technologies (GETs). Battery storage can provide short duration peak shaving capabilities, typically for 4-8 hours. Grid enhancing technologies are hardware and software solutions that improve the capacity, efficiency, and reliability of existing transmission lines. A key example is Dynamic Line Ratings (DLR), which optimize the current-carrying capacity of transmission lines by using sensors and software to adjust for factors like solar irradiance, wind speed and direction and ambient temperature. DLR has the potential to inform grid planning and operating processes through adjustment of thermal ratings to reduce the cost and time of capacity expansion, increase system utilization and enable faster interconnection of generation. Emerging long duration energy storage technologies, such as thermal energy storage, flow batteries or compressed air energy storage offer opportunities for 10 or more hours of storage and will become increasingly critical with higher penetrations of intermittent generation.

While customer technologies are outside of CMP's remit, visibility to available and emerging technologies to enable demand response, load management, and flexibility will help CMP plan for and enable flexibility. Available customer technologies with flexibility capabilities include smart thermostats, demand-response ready water heaters, electric vehicles/EV chargers, and battery storage. Emerging technologies such as smart electric panels and smart appliances are less prevalent but are also capable of load shifting or responding to time-of-use price signals. These technologies can participate in demand response or load management programs, such as managed EV charging, or respond to time-of-use price signals to shift energy usage away from peak periods, reducing strain on the grid and potentially deferring or mitigating the need for infrastructure upgrades.

Exhibit 6.4 Available and emerging technologies to enable load flexibility

	Available	Emerging
Grid Technologies	• Battery storage • Grid Enhancing Technologies (GETs) such as Dynamic Line Rating (DLR)	• Long duration energy storage • Dynamic Phase Balancing • Transformer Cooling Class Upgrade
Customer Technologies	• Battery storage • Smart thermostats • Smart water heaters • Smart EV charging	• Smart appliances • Smart electric panels
Foundational Technologies	• AMI • ADMS	• DERMS • Flexibility services platform

Improved load management can have the potential to help mitigate future peak load growth by shifting or optimizing when electricity is used, allowing CMP to reduce, defer, or avoid certain investments in network infrastructure. Flexible demand is becoming increasingly important with growing demand and more flexible devices, increasing opportunities to manage flexible loads to help optimize the grid. While electric vehicles and heat pumps are driving growth in demand, they also have the potential to be flexible, via managed EV charging and smart thermostats. Foundational platform technologies, such as ADMS and DERMs, can help CMP reliably meet demand when and where it is expected based on observed usage patterns, while also exploring opportunities to better manage and optimize demand.

To enable flexibility and load management capabilities, CMP envisions deploying ADMS and DERMS features in 2029 - 2030. In the near-term, CMP anticipates beginning evaluation and beginning the competitive solicitation process for a vendor.

6.2.2. Advanced Distribution Management System (ADMS)

ADMS is a software platform that enables near real-time visibility and control of the physical infrastructure making up the distribution system from the Energy Control Center. Traditionally vendors have offered a Distribution Management System (DMS) that can provide basic control features of Distribution assets via SCADA. However, in recent years with development of new control technology driven by growth in DERs and self-healing technologies, the DMS has 'Advanced' to the ADMS suite that includes the legacy DMS features with integration into Outage Management Systems (OMS), GIS, Fault Location, Isolation, and Service Restoration (FLISR) and DERMS features.

As the backbone of a modern distribution network management system, ADMS uses advanced algorithms, data analysis modeling features and in some cases artificial intelligence (AI) to perform near real-time optimization, configuration and operation of the electric distribution network and provide a level of real-time visibility that CMP's Distribution Operations Center (DOC) within the ECC has never had before. In particular, ADMS includes the ability to produce real-time load flow, which will be critical for the Company's distribution control centers to monitor and control a network with high DER penetration and ensure a more reliable and stable power supply for customers.

ADMS deployment will provide new and enhanced functionalities to operate the electric distribution system in Maine, which could improve asset management, optimize system performance, and reduce outage duration. Some examples of these functionalities include:

- Volt/VAR Optimization ("VVO") to monitor and adjust equipment settings (e.g., capacitor banks), resulting in improved voltage stability and reduced system losses;
- Fault Location, Isolation, and Service Restoration ("FLISR") to detect and isolate faulted section(s) and reconfigure the network to help reduce the duration of, and number of customers impacted by, sustained outages;
- Distribution power flow to perform distribution network analysis, resulting in improved short- and long-term system planning and decision-making;

Network wide deployment of ADMS is foundational to accomplishing the goals of the IGP in the long term. This fundamental grid modernization technology will improve reliability and resilience against extreme weather while enabling flexible management of load and DERs. ADMS supports Maine's policy goals via use cases that make it faster and easier to connect to the grid, enabling demand response and load shifting, and making it easier to identify the best location and configuration of energy storage.

The following is a summary of key benefits.

Customer benefits:

- Improved reliability, resulting from network operations ability to coordinate dispatch of ancillary grid services to improve power quality and reliability
- Enable the success of Demand Response, Load Shifting and Energy Storage programs
- Faster and more cost effective interconnections to the grid
- More efficient use of grid capacity, putting downward pressure on rates

System and planning benefits:

- Improves visibility into grid capacity and performance, enabling utility operations to see what is happening below the circuit transformer
- Improves load forecasting and better asset performance data to target the most prudent capital improvements
- Enables coordination of DER assets to optimize grid capacity
- Makes it easier to identify the best locations and configuration for energy storage
- Supports FERC 2222 compliance

ADMS Dependencies and Integrations

While the technology has the potential to be transformational, implementation is complex because many stakeholders are impacted, including customers, operations, planning and control center. The near-term dependency is to ensure data integrity of the digital grid model is accurate and integrations between systems are effective.

A successful ADMS deployment depends on EMS readiness, the completion of GMEP, and integration of AMI into CYME for distribution planning. In addition, CMP's deployment of ADMS is strategically dependent on the successful migration of GIS from the legacy Geometric Network (GN) to Esri's Utility Network (UN) model. To support this transition, CMP will conduct a Readiness Effort in 2026 focused on preparing GIS data, validating integrations, and confirming architecture for future systems. This effort will include data quality improvements, workflow mapping, and a Proof of Concept to ensure the Utility Network can serve as the foundation for advanced grid operations.

The Utility Network migration, expected to finish by 2029, will deliver significant benefits to CMP's grid modernization strategy. It will provide a more granular representation of assets and connectivity, improving asset management and enabling advanced analytics, and eliminate redundancies. It will also enhance workflows and optimize data consumption through better integration with mobility tools, real-time data sharing, and planning platforms such as ADMS and DERMS. These improvements will strengthen CMP's ability to manage topology efficiently, scale GIS performance, and enable smarter grid operations.

By completing the Utility Network migration before ADMS deployment, CMP ensures that its advanced control systems are built on a robust, accurate, and interoperable digital grid model, maximizing the value of ADMS and future technologies.

6.2.3. Distributed Energy Resource Management Systems (DERMS)

DERMS refers to a group of software products that operate together to actively track, plan, manage and operate DERs connected to the distribution network. CMP plans to develop and deploy DERMS features to monitor and control DERs, resulting in optimized resource management and system stability. The Company envisions DERMS as an ADMS application which will enable active coordination of demand response and load shifting customer programs. The DERMS investments will be used to enable:

- Flexible interconnection use cases: Reduce the time and cost of interconnecting new distributed generation projects, as well as connecting flexible new loads such as EV chargers and energy storage systems.
- Load management use cases: Pilot on circuits at ~95% capacity and use demand management to keep loading under threshold.

An ADMS platform with DERMS features would allow utility operations greater visibility to assess adverse impacts from DG to customers and equipment and capabilities to resolve them more efficiently. Assessing and resolving DG impacts is currently a manual process. With the proliferation of DG across the grid, the DOC Operators have had challenges in ensuring that segments of the grid do not overload as load and topology change. For example, if there is a loss of a large customer load on a circuit, or a reconfiguration such as a 'circuit tie' by switching the feed from one circuit to another, an Operator must manually assess the impacts of the DG site to the circuit, and resolve the impacts if the new configuration creates adverse conditions to either the quality of the power system or equipment itself. In some cases, reverse power flows from DG has exceeded nameplate substation transformer ratings. Even in areas where masked load or generation exists, DERMS features would allow operators to make more informed decisions and equip them with greater capabilities to maintain reliability and quality of the power grid.

6.2.4. Integration with customer programs to manage or incentivize optimal usage

With adoption of flexible customer technologies and foundational systems investments in network management platforms in place, realizing the potential for load management to optimize grid capacity utilization requires integration with customer programs and/or rate design to incentivize optimal usage. Flexible load management occurs when customers either change their behavior, for example turning down the thermostat or avoiding charging their EV during peak hours, or enroll in programs that automatically manage devices and shift load to off-peak hours, such as demand response or managed EV charging programs.

CMP recognizes the importance of collaborating closely with stakeholders including Efficiency Maine Trust (EMT) to maximize the value of demand response programs and load shifting technologies and explore opportunities for targeted flexibility. CMP currently has an opt-in time-of-use rate that provides price signals to shift energy usage to off-peak hours, giving customers the opportunity to save money by shifting energy usage and also encourage more efficient grid outcomes, putting downward pressure on rates for all customers.

6.3. DER Interconnection Process Improvements

Meeting Maine's climate targets requires continuing to interconnect and integrate renewables and clean energy resources to the electric grid. With a high penetration of DERs on the grid already and a large interconnection queue, there are several challenges to connecting and integrating DERs efficiently and cost effectively, including:

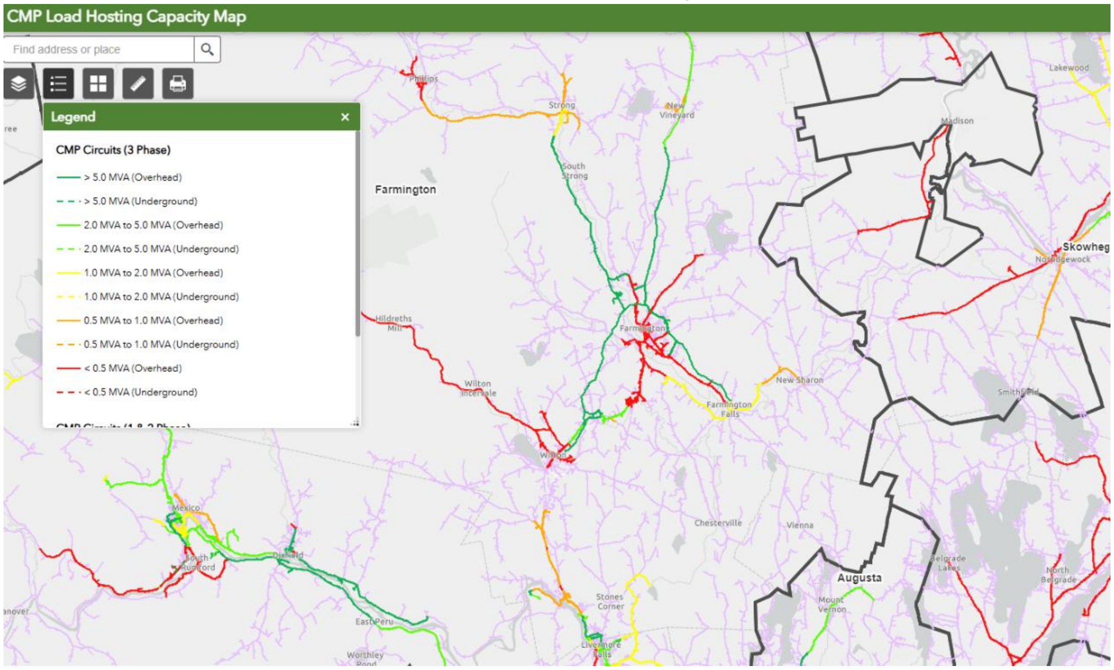
- The time it takes to process and evaluate DERs in the interconnection queue
- The cost of grid upgrades to accommodate proposed DER interconnections

To address these challenges, CMP will focus on improved hosting capacity maps, to provide developers with access to more relevant and granular information about the limitations and available capacity on the grid, and interconnection process improvements.

6.3.1. Hosting Capacity

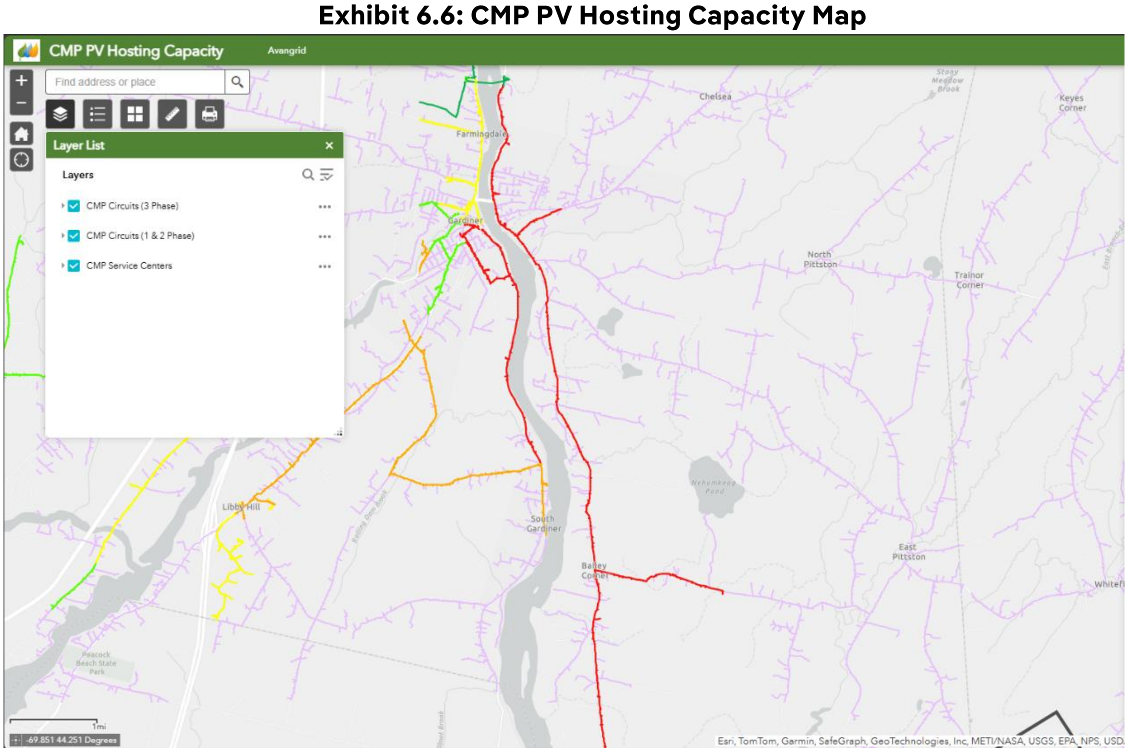
CMP has two hosting capacity maps, a Load Hosting Capacity Map and a PV Hosting Capacity Map, that show DER and load hosting capacity, including locational benefits of DER and areas of existing or potential system congestion. The Load Hosting Capacity map displays the estimated remaining load capacity on the distribution circuits and substation transformers to help identify where load may be able to connect with minimal needs for distribution system upgrades. For example, circuits in green have available capacity, as shown in Exhibit 6.5 below.

Exhibit 6.5: CMP Load Hosting Capacity Map



The PV Hosting Capacity map displays how much generation can be connected at a given location before thermal overloads are created. The PV Hosting Capacity was created for solar generation but can be used for other methods of generation. Exploring the PV hosting capacity map shows areas with available capacity and system congestion.

Exhibit 6.6: CMP PV Hosting Capacity Map



CMP is currently updating both maps on a yearly basis with updates to individual circuits and substations when major changes occur (e.g., a substation transformer is upgraded, a new circuit is built, a large load transfer is performed from one circuit to another). Updating these maps is currently a manual process, which entails creating a CYME model for each substation being updated and running CYME's Integration Capacity Analysis (ICA) module to determine the available load or generation capacity at all three phase locations on a circuit. CMP is working towards streamlining the process with an aim to reduce the time it takes to update the hosting capacity maps, allowing the maps to be updated more frequently.

CMP needs updated software and systems to improve hosting capacity maps by enhancing system data and visibility. Utilities require consistent, high-quality data on DER performance and grid conditions to manage dynamic operations safely. Improved data management, advanced forecasting tools, and situational awareness systems are essential for this information exchange, enabling CMP to provide transparent, detailed hosting capacity information for informed siting and design decisions. To achieve this, as discussed above in Section 6.1, CMP is modernizing its distribution planning and modeling platforms, migrating to a centralized CYME server environment for faster scenario analysis and better integration of AMI and SCADA data. These updates are crucial for evaluating DER impacts under variable conditions and updating hosting capacity assessments as the grid evolves. Modernizing software platforms ensures seamless data exchange with critical systems like CYME, SCADA, and GIS, helping CMP manage the large volume of real-time data associated with flexible interconnections, as many current platforms are not suited for modeling variable DER behavior or dynamic system responses.

CMP recognizes that standardized hosting capacity maps across utilities benefits stakeholder decision making and commits to working with Versant on establishing standards as the maps continue to be updated.[32]

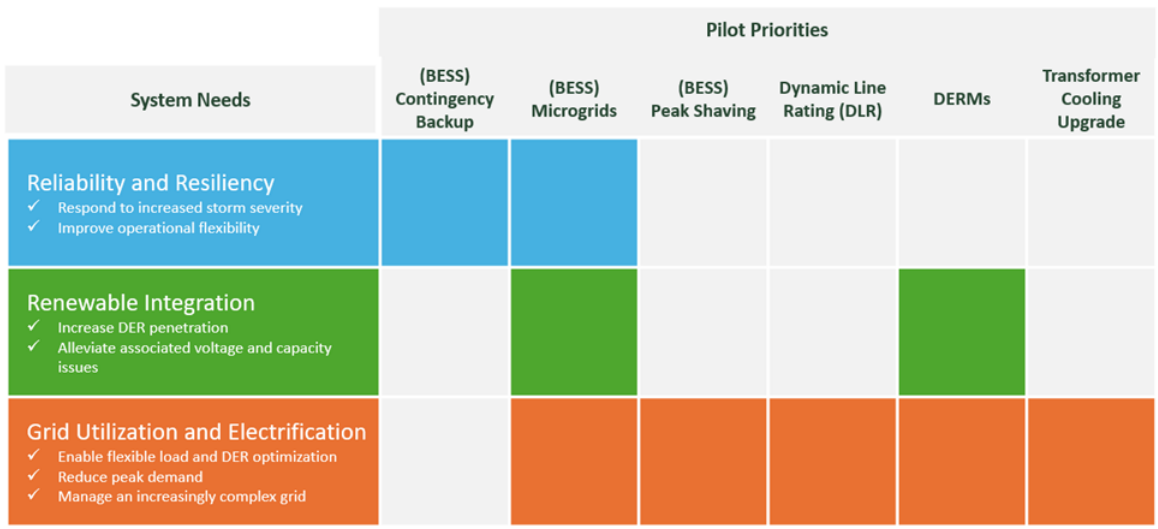
CMP is taking significant steps to enhance its interconnection application process and improve queue transparency, ensuring timely and efficient project delivery. Key initiatives include the introduction of regularly updated public dashboards, such as hosting capacity maps, accessible through the CMP Interconnection Portal to provide greater visibility into application status. CMP is also strengthening coordination with ISO-NE to align studies and timelines, while maintaining consistency in queue processing in accordance with MPUC Rule Chapter 324 and CMP's terms and conditions. Continuous monitoring of regulatory requirements and potential rule changes allows CMP to implement process adjustments promptly, preventing delays and safeguarding queue integrity. To further support developers, CMP prioritizes proactive communication by sharing cost estimates and project schedules during regular meetings, enabling informed decision-making. In addition, CMP is exploring flexible interconnection models, such as ADMS and DERMS, which allow for managed or curtailed load to accelerate solar and storage integration. While previous ANM proposals raised funding mechanism concerns that require resolution, CMP remains committed to working

[32] "The consensus among stakeholders with regards to hosting capacity maps is that they are not viewed as a top priority at this time and that the efforts required to significantly enhance them or standardize them would be better served elsewhere (e.g., improving the interconnection process)." IGP Order, p. 31.

collaboratively with stakeholders and regulators to advance these technologies and modernize interconnection practices.

6.4. Pilot projects

CMP aims to address key challenges through targeted pilot projects. While the implementation of new technologies comes with reasonable concerns about scalability and sustainability, CMP will leverage learnings from peer utilities, industry consortia, and academia to evaluate the Technology Readiness Level (TRL) of promising solutions. CMP considered available and emerging technologies to meet key system needs and challenges, which informed the development and prioritization of potential pilot projects.



6.4.1. Available Technologies Explored for Pilots

As CMP evaluated pilot opportunities to address grid needs, CMP explored how it can utilize existing technologies to improve reliability and resiliency, renewable integration and grid utilization and electrification. This assessment focused on Battery Energy Storage Systems, Demand Response / Flexible Demand Management, and Dynamic Line Ratings (DLR).

Battery Energy Storage Systems (BESS)

As highlighted in the DOER's Maine Energy Plan, Maine Pathways to 2040, and Assessment of Storage Procurement Mechanisms and Cost-Effectiveness in Maine reports, energy storage is becoming and will continue to be a critical part of maintaining reliable electric power across the state. Different configurations of BESS can address capacity, voltage, and reliability needs in addition to assisting in the adoption and efficacy of DERs. As costs decline, BESS systems that can address both traditional as well as emerging system needs can be a cost-effective alternative to traditional poles and wires solutions in some cases. CMP has considered various BESS applications, including:

Peak Shaving BESS: BESS can be used as a solution to address overloading situations as they can be sized to address peaks on heavily loaded and/or constrained circuits. In addition, these systems can provide additional services such voltage support, frequency regulation, and contingency support when appropriately sized and configured. In some cases, a peak shaving BESS, named for its ability to “shave the peaks” that would otherwise stress the system, can defer or avoid more expensive traditional distribution infrastructure upgrades, covering the potential thermal overload on a substation transformer. This is aligned with CMP’s commitment to appropriately sizing systems to reliably meet demand, focusing on minimizing cost impacts on customer rates while also protecting assets across the service territory.

Battery Storage Backup for Reliability: With an increase in both the frequency and severity of storms, CMP must constantly assess the reliability and performance of its system to determine how best to provide safe, reliable service to all customers in its service territory. Long, radial transmission lines into less densely populated areas, many of which are identified by the Climate & Economic Justice Screening Tool (CEJST) as a Disadvantaged Communities (DAC), are at particular risk for outage during storms and modern solutions must be implemented to mitigate or avoid outages for these customers. BESS in tandem with appropriate sectionalizing devices could potentially be configured to create electrically independent “islands” that can either be backed up for the duration of an anticipated outage or in tandem with DERs as self-sustaining microgrids, however the success of such a project depends upon continuous connection of a generation source or the battery, and sufficient battery capacity to meet demand over a given period.

Collocating BESS with a DER: The colocation of DERs with battery storage can mitigate the intermittency of solar and wind resources and provide voltage support.

Mobile Battery Energy Storage Solution (MBESS): A MBESS could provide a flexible solution for immediate load relief in areas facing capacity constraints while enabling operational flexibility by deploying during peak demand and removing during off-peak periods to provide planned outage or storm restoration support. An MBESS could also allow utilities to defer costly infrastructure upgrades or implement phased strategies through Bridge-to-Wire solutions.

Demand Response / Flexible Demand Management

Flexible demand management includes measures such as DR programs and time-varying rates that can incentivize flexible loads like controllable thermostats, EV charging and energy storage to shift load away from peak to non-peak times of day.

Dynamic Line Ratings (DLR)

Dynamic Line Ratings (DLR), was also explored as an available technology, as it can optimize the current-carrying capacity of transmission lines by using sensors and software to adjust for factors like wind speed and temperature. DLR has the potential to inform grid planning and operating processes through adjustment of thermal ratings to reduce the cost and time of capacity expansion and enable faster interconnection of generation. A DOE study indicates that DLR allows for 5-25% more capacity than static line ratings (SLRs).

While several different types of DLR technology are commercially available, the key mechanisms in any DLR system are (a) the installation of sensing or monitoring hardware on or near targeted transmission lines to measure the line’s temperature, sag, or tension; and (b) a software interface that can process any collected data into actionable insights into the line’s condition. Implementation typically starts by deploying a model for planning followed by installation of sensors to validate the model to scale the technology across the transmission network.

6.4.2. Emerging technologies being explored

In addition to existing technologies, CMP evaluated the potential use of emerging technologies to support future pilots. This includes dynamic phase- balancing, transformer cooling, and long duration energy storage.

Dynamic Phase-Balancing (Phase-EQ)
Driven by the rapid growth of DERs, including solar, storage, electric vehicles, and other evolving grid demands, the power industry is increasingly seeking flexible and intelligent solutions to improve power quality and expand distribution system capacity. Phase-EQ is an advanced distribution automation device designed to dynamically balance power flow across the three phases of an electrical distribution circuit. It enables precise control of real and reactive power exchange between phases, enhancing circuit performance, stability, and overall power quality.

Installed as a shunt device on the distribution network, Phase-EQ actively corrects phase imbalances, enhancing efficiency and reliability without requiring major infrastructure upgrades. Given its ability to defer traditional infrastructure investments while offering a more favorable cost-benefit balance for both ratepayers and utilities, this device is a strong candidate for evaluation in NWA applications.

Transformer Cooling Class Upgrade
As transformers convert between two voltage levels, heat is generated as loss. This heat is generally the primary limitation for the power capacity of a transformer, and the rise in temperature during operation is used in determining the rating. Substation transformers come in 3 primary cooling classes, each providing an improvement in the thermal capacity of a given transformer. Oil Natural Air Natural (ONAN) which has no active cooling component, instead relying on natural convection. The next step up is Oil Natural Air Forced (ONAF) where air is forced over the protruding radiator fins using fans, but the oil is still not circulated. Finally, Oil Forced Air Forced (OFAF) is when air is forced over a radiator that the oil is pumped through, using the dielectric fluid as the working fluid in a heat exchanger to push cooler oil over the coils and core of the transformer.

Each improvement in cooling class is expected to yield between a 25-33% improvement in thermal performance. As the vast majority of transformers on CMP's system are of the commonplace ONAF configuration, investigation is underway into utilizing an external oil cooler, effectively upgrading to an OFAF configuration, to extend the capacity of existing transformers. This would allow for the expansion of distribution capacity at a fraction of the cost of a new substation transformer, deferring a costly upgrade.

Long Duration Energy Storage
As the grid continues to move to a higher penetration of intermittent resources and shifts toward a winter peaking system, there will be a need for long-duration energy storage to help manage the grid, particularly in locations with significant renewable penetration during

extended periods of low renewable generation. While some types of long duration storage technologies (i.e. pumped hydro) are established and available, emerging long duration technologies such as iron air BESS and thermal storage have lower round trip efficiencies than typical electro-chemical BESS, are generally lower cost at scale and have longer lifetimes. There is an opportunity to leverage these technologies in DERMs programs as they can be charged during times of excess DER generation and dispatched when the DER is not producing. CMP will monitor the deployment and results of Maine's first long duration iron air storage project and assess learnings.

6.4.3. Pilot Project Concepts

CMP developed pilot candidates for several of the available technologies explored, including identifying candidate locations and use cases. All of the pilots discussed below are in early stages of development, except for the DER optimization pilot, which is anticipated to begin in early 2026.

Peak Shaving BESS Pilot

Through the IGP modeling and solutions evaluation, CMP identified a potential candidate for a peak shaving battery energy storage pilot to meet a projected transformer overload, as described in Case Study 4 in Section 5.2. The circuit selected serves just over 1,000 customers and falls in part within a CEJST identified DAC. According to load growth projections, this transformer will be overloaded by the winter 2033, necessitating urgent mitigation measures. In addition, this circuit is already suffering from elevated levels of reverse power flow due to DERs on the circuit which could lead to premature asset degradation.

Exhibit 6.7: Transformer Overload Mitigated by Peak Shaving Action

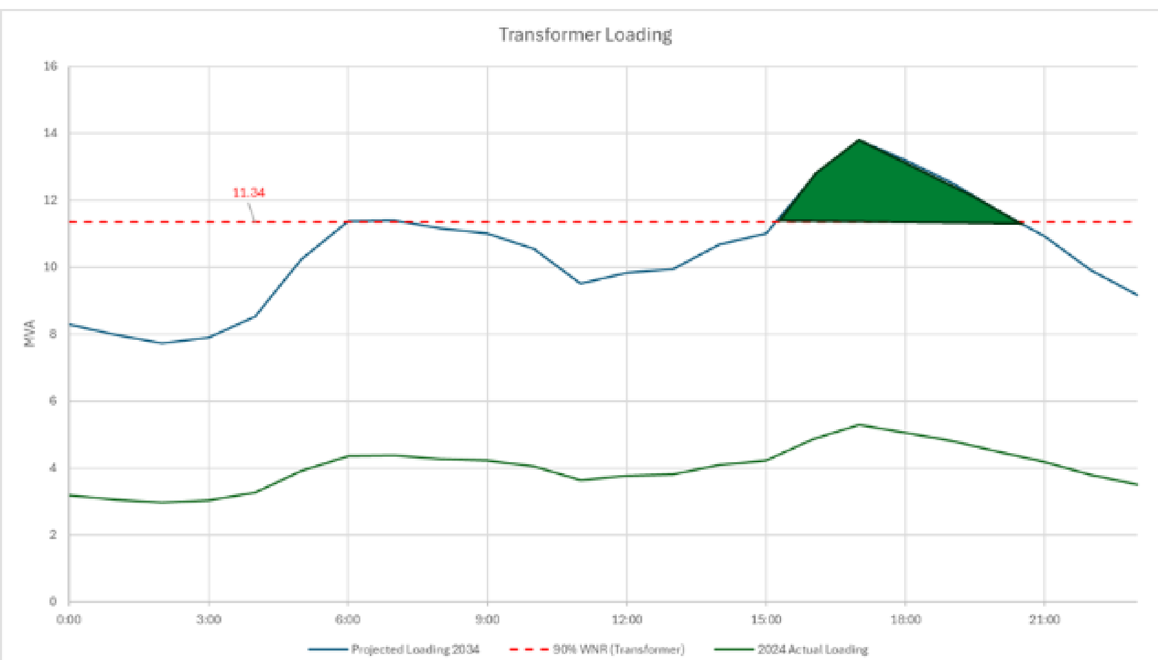
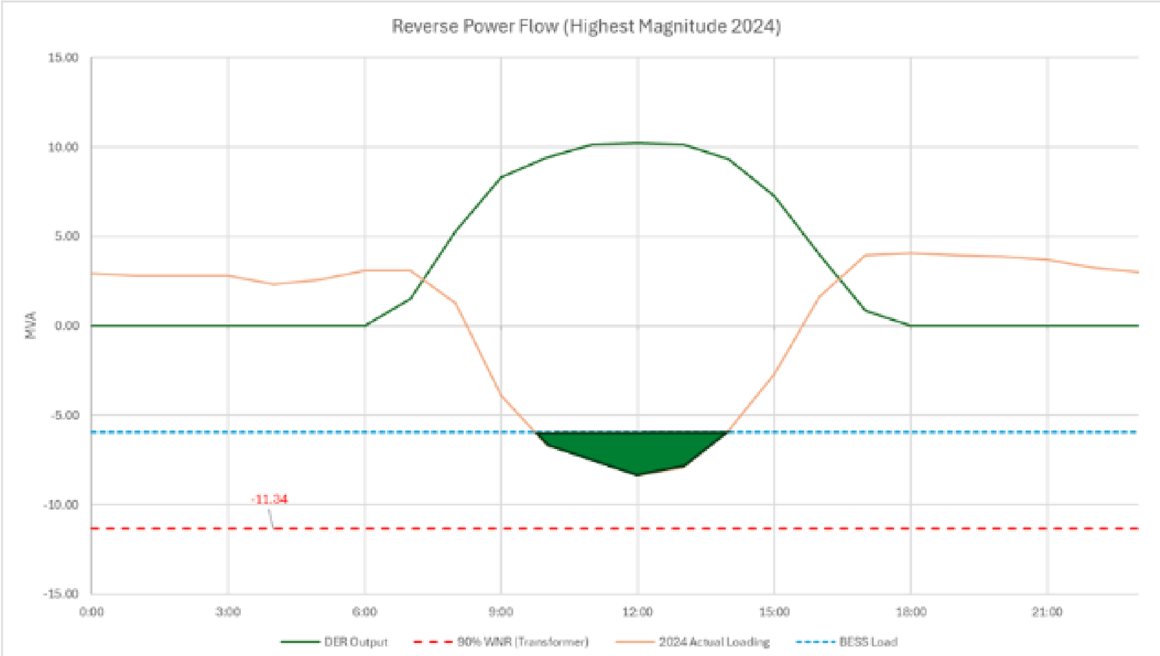


Exhibit 6.8: Reverse Power Flow Reduced by Charging BESS



The traditional solution would be to upgrade the existing 10MVA transformer to a 14MVA. A 2.4 MW 10.8 MWh peak shaving BESS downstream from the substation transformer for peak shaving operation alleviates the overload on the existing transformer by dispatching when the transformer would be loaded over its rating, addressing the same need as the traditional solution while providing the additional DER hosting support. The proposed BESS solution would be novel for CMP's service territory in using a utility owned and controlled BESS to mitigate risk of failure due to thermal overload. This solution would meet the distribution capacity needs at the substation and allow for more operational flexibility. In addition, it would provide a large flexible load to avoid having to curtail DER generators in case of excessive reverse power flow and protecting the transformer. CMP has numerous rural and remote circuits throughout its service territory facing similar infrastructure limitations amidst uncertain load growth projections, and this project would be considered a proof of concept for this BESS use case. If piloted successfully, CMP could seek to use BESS as solutions alternatives to address reliability and resilience concerns, as well as defer load driven distribution upgrades across its system when existing infrastructure asset condition allows, and particularly in cases where upgrades are driven by uncertain forecast peak load levels or by short periods of overloading.

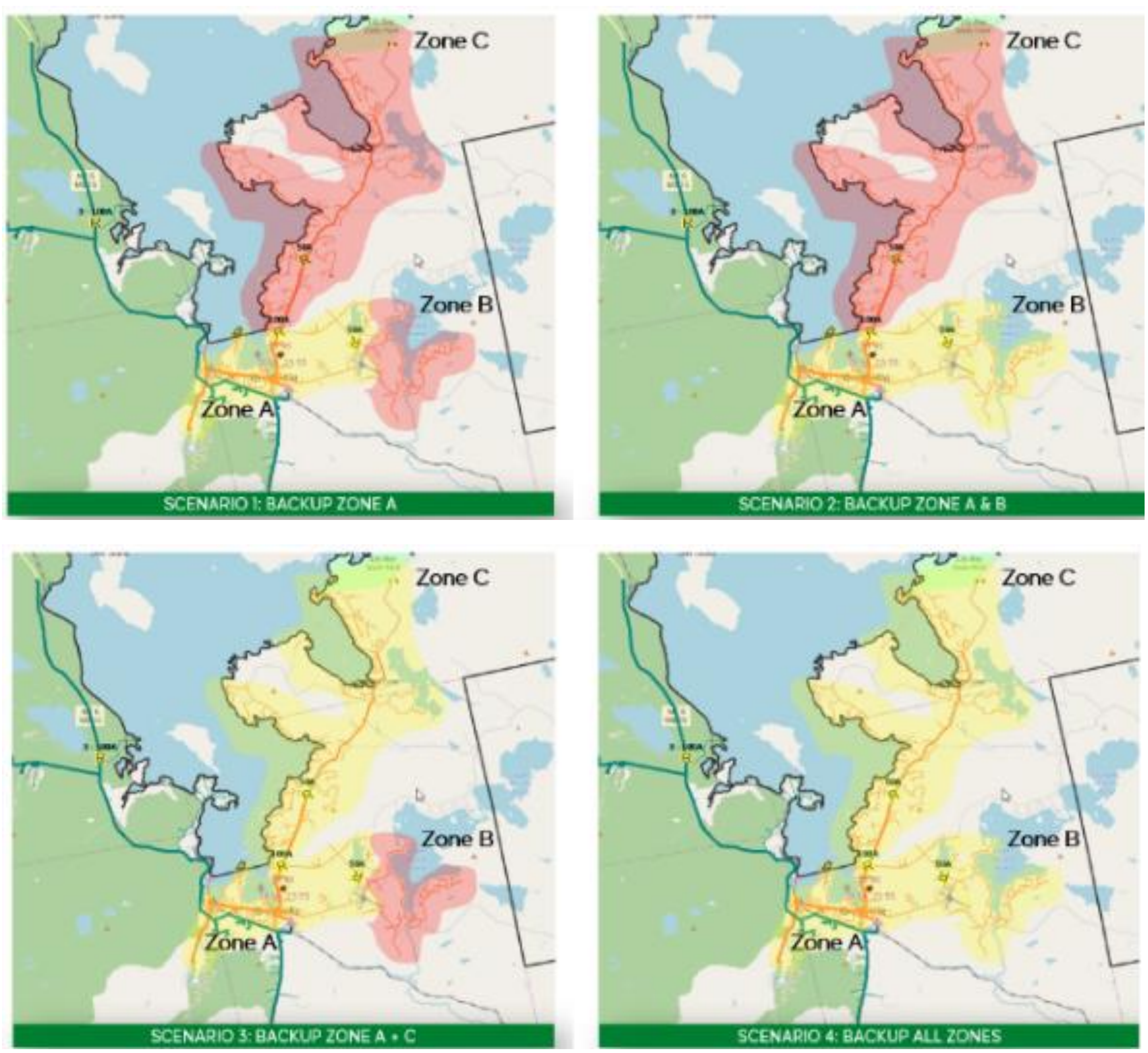
Battery Energy Storage Backup for Reliability Pilot

CMP identified a potential candidate and performed analysis for a backup BESS as part of a DOE grant (DE-FOA-0003428[33]) concept paper. The selected circuit is unique because even though it is remote and radial, over 50% of its customers are in the downtown area, including several critical community facilities and the only hospital within a thirty-mile radius. CMP investigated two traditional solutions in addition to the BESS. First, building a redundant tie

[33] Funding opportunity canceled May 31, 2025.

would require a new right-of-way through a densely forested public reserve (a common occurrence in the state) which in addition to anticipated permitting challenges and unfavorable conservation land impacts, would be prohibitively expensive at an estimated $39.02M. The other alternative would be a combination of line hardening actions include steel poles, tree-wire, spacer cable, undergrounding, and/or enhanced vegetation management on the radial transmission line which would cost an estimated $22.4M. The BESS backup was sized to supply the downtown for six hours, or a larger portion of the circuit for a shorter period if there are no outages downstream of the reclosers as is represented in Exhibit 6.9.

Exhibit 6.9: Zones of Operation for the BESS Backup



The 2.6MW, 22MWh BESS at the substation downtown, along with one new three phase SCADA recloser and two new single-phase SCADA reclosers on distribution lines leaving downtown would provide backup power for the customers within the area for 6 hours at an estimated cost of $14.88M. This system could also provide voltage support and/or frequency regulation when appropriately sized and configured. This project would greatly improve reliability and resiliency of electrical service for all customers in the islanded area, with an estimated circuit SAIFI improvement of 49%. As one of the most remote and radial circuits in CMP's service territory, the community experiences frequent outages and are often forced to rely on expensive and dirty diesel generators. The backup source could ensure that residents have reliable access to power, even during severe storms that regularly cause outages.

Exhibit 6.10: Western Maine Lakes Region

Dynamic Line Rating (DLR) Pilot

CMP has been actively collaborating with partners such as DOER and various suppliers on Dynamic Line Rating (DLR). Through this work, CMP identified transmission circuits in the Western Maine Lakes Region as promising candidates for piloting this technology. The series of line sections in this area connect upper and lower Lakes Region, and network flows can ebb and flow bidirectionally. Depending on the network flows and system conditions, the western lakes region lines can become heavily loaded with little to no generation online in that area. The addition of DER in that area can exacerbate the load flow conditions and, in many cases, has caused both thermal and voltage system issues.

In the past, this area posed challenges to advance DER interconnections. Significant system upgrades, such as line re-rates were required for these interconnections. This added complexity to the timeline to meet the State NEB deadlines and financial commitments required for DER interconnections. As a result, a significant number of DG projects in this area withdrew from the queue. Currently there are approximately thirteen DER projects with a total of approximately 32 MW which is in addition to the approximate 22 MW of existing hydroelectric generation in the area. The proposed DER increase would produce thermal overloads and therefore corrective actions should be implemented.

The most significant and costliest upgrades needed in this region would require upgrading the line ratings of line section 143, 170 and 91 for a length of 32.2 miles of reconductoring for an approximate cost of $97 million and 10 years to build. Given the high cost and long time to implement, CMP assessed additional options.

One of these options would be to utilize DLR, a technology that calculates a transmission line's real-time current capacity based on actual environmental conditions, such as temperature, wind, and solar radiation, rather than relying on static, conservative estimates. By using sensors and software, DLR optimizes the use of existing infrastructure, allowing utilities to increase power flow, defer costly upgrades, and better manage the grid's performance.

The implementation and management costs of DLR are much smaller than the infrastructure upgrades to the Western Lakes Region 34.5 kV backbone, while the full implementation for DLR would be in months instead of years. This would provide CMP with additional line capacity while the long-term upgrades to the local system hardware continues through its construction processes. In turn, the return on the DLR investment would allow more DER to interconnect in the Western Maine Lakes Region.

DER Optimization Pilot

CMP is evaluating the functionality of a manual integration of SCADA and Energy Management System data and controls with CMP's Energy Control Center (ECC), which could be utilized to protect grid assets from exceeding thermal limits and low voltage conditions caused by the reverse power flow from DERs. This program would entail a binary on/off fail safe that could be programmed to trip the SCADA when defined limits are exceeded. It could be a targeted component to a flexible interconnection capability when used to operationalize the dynamic operating parameters modeled by other software tools including ADMS.

An initial pilot on a feeder circuit identified by CMP as having high distributed generation penetration and existing SCADA is underway, and is anticipated to be in production in early 2026.

Piclo Pilot for Flexibility

United Illuminating (UI), CMP's sister utility in Connecticut, is currently piloting a flexibility marketplace with Piclo, and CMP could adopt lessons from that experience. CMP could partner with Piclo, a flexibility services platform, to test a marketplace for non-wires alternatives and DER flexibility. The pilot would allow CMP to post locational grid needs, such as peak load reduction or voltage support, on Piclo's platform, enabling aggregators and DER providers to bid their services competitively to potentially provide load management for peak reduction.

Targeted Collaboration with EMT for Behind-the-Meter Batteries on Certain Circuits

CMP and Efficiency Maine could collaborate on a pilot geotargeted behind-the-meter battery initiative to manage load growth and defer costly distribution upgrades. Under this approach, Efficiency Maine would leverage the DER Initiative in its current Triennial Plan to deploy small residential or commercial batteries on circuits forecasted to become lightly constrained in the mid-future. CMP would provide circuit-level forecasts and identify priority areas, while Efficiency Maine would offer performance-based incentives to aggregators or customers for installing batteries capable of shifting load away from peak periods. These batteries could be paired with solar PV or installed as standalone backup systems, integrated into CMP's DERMS platform for real-time dispatch and verification. By strategically locating storage resources, this partnership could enhance grid flexibility, reduce peak demand, and potentially avoid or defer traditional wires investments.

07. Environmental, Equity, and Environmental Justice

7. Environmental, Equity, and Environmental Justice

CMP is committed to meeting high standards of environmental stewardship in the communities it serves and to conducting business in a manner that minimizes adverse environmental impacts on present and future generations. These commitments are demonstrated in CMP's normal course of business through Biodiversity, Climate Change, Environmental and Sustainability policies[34], which provide principles and governance to guide CMP’s strategy and business operations.

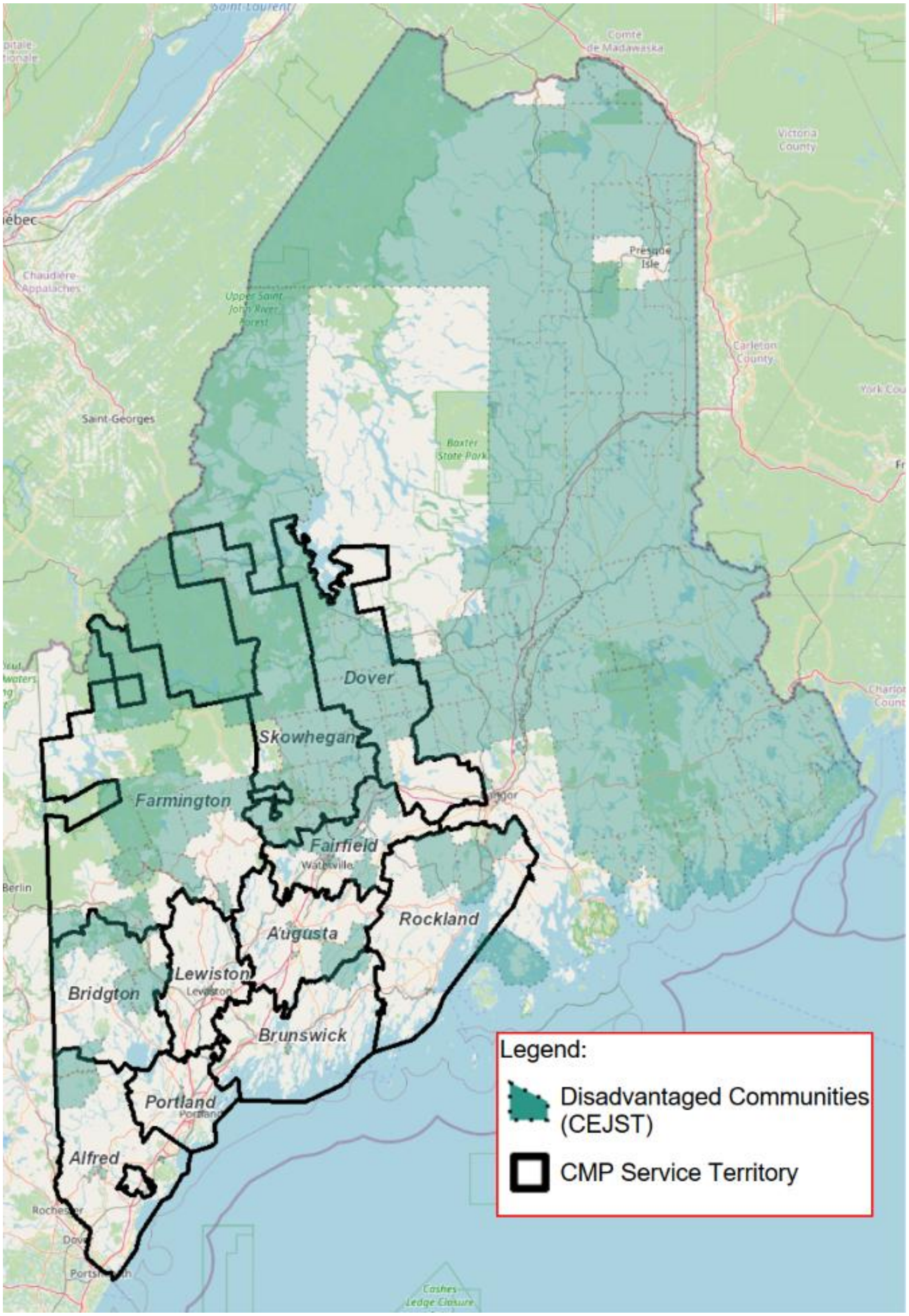
As the shift to new electric products, such as heat pumps and electric vehicles, continues to shape the future of the electric grid, CMP understands that these shifts impact different types of customers in different ways. The Company considers the potential impacts that more extreme weather or new energy technologies could have on communities and customers in its service area, particularly low- and middle-income customers in both urban and rural areas. Many customers rely on CMP’s low-income assistance program, known as the Electricity Lifeline Program, and tools such as Energy Manager and Usage Alerts, for assistance and ways to save.

The IGP statute requires “an assessment of the environmental, equity and environmental justice impacts of grid plans”. “Environmental Justice” is defined in the statute as “the fair treatment and meaningful involvement of all persons regardless of race, color, national origin or income with respect to the development, implementation and enforcement of environmental laws, rules, regulations and policies”. Maine Public Utilities Commission rules[35] further define “Environmental Justice Populations” as “geographically or demographically defined groups of people with median household income and employment below the statewide median household income and unemployment rate who have environmental justice concerns.”

CMP used the 2024 Climate and Equity Justice Screening Tool (CEJST), which was suggested by several stakeholders including the DOER, to identify disadvantaged communities and evaluate potential impacts in investment planning. For instance, CMP used the CEJST in its distribution planning process to identify target circuits for resiliency upgrades as part of a distribution automation program. As part of the circuit selection process for this program, CMP set a target for 85% of customers that will see reliability and resiliency benefits from new automation devices to be located in disadvantaged communities. The CEJST map below shows where disadvantaged communities are located within CMP’s service territory.

[34] https://www.cmpco.com/ourcompany/givingback/caring-for-the-environment
[35] https://www.maine.gov/mpuc/about/intervenor-funding

Exhibit 7.1: Map of Disadvantaged Communities



7.1. Overview of EEEJ impact areas and considerations in the planning process

As required in the IGP Order[36], the scorecard used to evaluate potential solutions to grid needs identified in the IGP planning process includes three EEEJ criteria: equity, emissions impact, and local environmental impact. CMP aligned with Versant on the following definitions for EEEJ criteria:

- Equity: Does the affected grid infrastructure serve disadvantaged customers? Equity impacts were evaluated by location. A locational analysis of the grid needs identified determined whether each grid asset served a disadvantaged community using the CEJST 2.0 data set.
- Emissions: Does the solution increase or decrease emissions? Emissions impacts were evaluated by solution based on their ability to directly or indirectly reduce emissions. Examples of direct emissions reductions include reducing peak load, reducing losses, or decreasing maintenance requirements. Emissions may be indirectly reduced by increasing grid capacity for renewables and beneficial electrification, for example with an infrastructure capacity upgrade or GETs.
- Local Environment Impact: Does the solution require development of new land? Local environmental impacts were evaluated by solution based on whether the solution will require development of new land. New land development can have negative impacts on the environment such as disturbing wetlands, wildlife and habitat loss, displacing farmland or affecting water runoff and flooding.

The following table provides an overview of the assessment criteria used to evaluate each of the EEEJ metrics:

EEEJ Metric	Metric Measurement	Comparative Assessment Scorecard		
Equity	Does affected grid infrastructure serve disadvantaged customers?	High Over 67% in a DAC	Medium Between 33% - 67% in a DAC	Low Less than 33% in a DAC
Emissions	Does the solution increase or decrease emissions?	High Direct emissions reduction	Medium Indirect emissions reduction	Low Emissions increase
Local Environmental Impact	Does the solution require development of new land?	Low No new land use or reduces land use	Medium Moderate increase in land use	High Increases land use

The EEEJ criteria were considered and evaluated holistically with the other scorecard criteria, as described in Section 6.1.3 of the Solutions Identification and Evaluation chapter. While the

[36] Attachment D to the IGP Order identifies the three EEEJ evaluation categories as "Equity", "Emissions impact" and "Local Environment impact".

emissions and local environmental impact criteria have clear positive to negative assessment rankings for each solution, the equity assessment is largely focused on providing visibility into where grid needs and proposed solutions fall within disadvantaged communities. CMP expects that the weighting of environmental, equity, and environmental justice impacts against other scorecard categories will be project-specific. CMP anticipates that the interpretation and application of the scorecard criteria, in particular the equity metric, to evolve and be refined in future grid plans.

7.2. Stakeholder outreach

CMP's stakeholder outreach has been extensive, including stakeholder meetings at each of the three formal milestones as required by the IGP Order, as well as meetings with technical stakeholders, disadvantaged communities, emergency response personnel, municipal representatives, business stakeholders, legislators, the general public, and tribal representatives.

As discussed in Section 1.2, CMP conducted a series of stakeholder engagements throughout the Integrated Grid Plan (IGP) and Climate Change Protection Plan process:

- April 16, 2024 – Initial stakeholder meeting introduced CMP's role, regulatory obligations, grid challenges, and climate vulnerability. Outlined resilience strategies, federal funding opportunities, and the 10-year roadmap for reliability and climate goals.
- August 13, 2024 – Provided updates on the Climate Change Vulnerability Study, explained mitigation vs. adaptation measures, reviewed LD 1959 requirements, and discussed load forecasting and planning priorities.
- January 27, 2025 (Milestone 1) – Focused on technical inputs for system modeling, planning scenarios for electrification and DER adoption, and stakeholder engagement plans.
- August 25, 2025 (Milestone 2) – Identified system needs using scenario-based forecasts, highlighting urban growth, winter peak dominance, and overload/voltage risks across substations and circuits.
- November 25, 2025 (Milestone 3) – Presented solution development framework using a scorecard approach, covering upgrades, storage, automation, and enabling technologies. Shared near-term actions and long-term strategies for DER integration and hosting capacity.

Additional Engagements:

- Technical Stakeholder Meetings – 20 sessions with organizations such as DOER, OPA, EMT, NRCM, CLF, Acadia Center, and others for feedback on technical content and accessibility.
- Other Technical Engagements – Included two "Municipality Day" events, emergency management sessions, nonprofit outreach, and numerous key account meetings to address specific priorities.

Importantly, earlier stakeholder feedback emphasized the importance of EEEJ-focused engagement and cautioned that standalone grid planning meetings might not attract broad participation. Stakeholders recommended embedding grid planning topics within existing partnerships and outreach efforts to build on established trust and familiarity. They also suggested that community organizations could help share information rather than relying solely on CMP. Acting on this guidance, CMP integrated grid planning outreach into customer and local-level interactions, primarily through existing relationships and processes, as detailed in this section.

In 2025 alone, CMP participated in more than 70 events across its service area, assisting over 300 individual customers. These events were held at accessible locations such as town halls, food pantries, YMCA facilities, and community action agencies. CMP staff provided support on billing and energy usage, storm readiness, and enrollment in assistance programs like the Arrearage Management Program and Electricity Lifeline Program. By meeting customers where they already engage and starting with topics most relevant to their needs, CMP gathered valuable insights into customer priorities that informed this grid plan.

To further promote transparency and accessibility, CMP launched a dedicated webpage featuring an overview of the Integrated Grid Planning process and Climate Change Protection Plan, along with resources for stakeholders to stay informed. The site offers email sign-up and a feedback channel, and hosts PUC docket materials in a user-friendly format for those unfamiliar with regulatory systems. CMP posted all milestone meeting materials in advance and uploaded recordings afterward, ensuring that stakeholders—including those unable to attend live sessions—could access the same information and participate meaningfully. This approach was designed to reduce barriers and advance equity in outreach.

Additionally, CMP committed to working with the town of Belfast, a CEJST-designated disadvantaged community, through the federal Energy Transitions Initiative Partnership Project (ETIPP), which supports clean energy and resilience planning for remote and island communities. CMP is also collaborating with the Island Institute to provide educational resources on grid planning and operations for rural and coastal communities.

As part of CMP's project outreach, CMP also engaged in 53 disadvantaged communities since the beginning of the grid planning process to educate and understand concerns and impacts related to project development, construction, and commissioning. This is an important part of CMP's outreach to communities affected by development of the electric grid, and aligns well going forward with the scorecard approach discussed at Section 5.3.3. As example, changes in project design were made to a significant Portland project based on feedback received through this process from residents and the City.

CMP also maintains representation on the Electric Ratepayer Advisory Council, which is charged with evaluating the affordability of electricity in Maine and advising the Public Advocate on potential savings measures; on the board of the Area Agencies on Aging, which are local nonprofits serving older adults, people with disabilities, and their caregivers; on the Energy Working Group of the Maine Climate Council; and on various temporary stakeholder groups focused on energy planning, equity, and climate, such as the DOER's Transmission Infrastructure Study Stakeholder Group.

This Integrated Grid Plan and associated stakeholder process is an important step in increasing the transparency of forecasting, needs identification and solutions evaluation, as CMP, the MPUC, the DOER and stakeholders collectively develop an understanding of what is needed to meet Maine's climate targets. The IGP stakeholder process provided multiple opportunities for stakeholders to ask questions or provide feedback, including the pre-milestone and milestone meetings. CMP provided an overview of the scorecard criteria, including the EEEJ metrics and assessment criteria, at the Milestone 3 meeting November 25, 2025.

Feedback centered on planning for reliability and resiliency, ensuring sufficient capacity for access to distributed generation opportunities, reducing impacts related to project construction, and planning for community safety during hazardous weather events. This feedback is reflected in the grid plan's identification of cost-effective capacity solutions to enable DER integration and load growth, hardening to reduce storm impacts, and in the data and planning roadmap to ensure that foundational systems enable technologies that assist with storm response as well as non-traditional reliability and resiliency upgrades like battery storage or demand response.

CMP believes that the evaluation of EEEJ impacts on the grid plan will be a collaborative effort that will evolve over the course of future filings. Additional outreach is planned in the evaluation and scoping of specific projects in disadvantaged communities where CMP plans to provide information and invite input from stakeholders. CMP plans to continue meeting with community leaders and incorporating feedback into the grid planning and solution development process.

CMP will continue prioritizing equity, environmental, and energy justice in future outreach by hosting community connection events at familiar locations, maintaining representation in organizations and working groups focused on affordability, equity, and climate, and conducting project-level engagement in disadvantaged communities to incorporate feedback into design. CMP will also sustain partnerships with ETIPP communities and the Island Institute to support clean energy and resilience planning, while working closely with municipalities and emergency management personnel to ensure hazard impacts are understood and addressed to protect vulnerable populations. As this grid planning process is iterative, we also anticipate robust stakeholder participation in the next grid planning docket and during the next grid planning cycle, which is scheduled to begin in 2027.

7.3. Evaluation

CMP recognizes that the solutions required to address the needs identified in the IGP, as well as advance the IGP priorities, have both costs and benefits. While grid investments are prioritized to meet critical needs based on engineering assessments, CMP will prioritize fair and equitable distribution of costs and benefits to the extent possible, and that starts with visibility and transparency. The benefits of the grid plan include:

- Increased system capacity
- Increased DER hosting capacity

- Reliability and resiliency improvements, through investments in substation and circuit hardening, distribution automation and proactive asset management
- Direct emissions reductions through solutions such as reconductoring, which reduces losses, and battery storage, which decreases peak load
- Indirect emissions reductions, through investments to increase grid capacity for renewables and beneficial electrification, as well as through investments such as ADMS and DERMS which enable flexibility

CMP acknowledges that customers with lower incomes tend to have higher energy burdens and feel a disproportionate impact of rising costs. Historically, customers in Disadvantaged Communities have borne the highest energy burdens. CMP's Electricity Lifeline Program provides assistance to low-income customers to help lower their cost of electricity. CMP will monitor and evaluate the effectiveness of this program over the term of the first IGP in providing equitable assistance, looking for opportunities to increase awareness and improve equity.

To track these impacts, CMP will incorporate tracking the three EEEJ scorecard metrics into existing processes for visibility and transparency.

EEEJ Metric	Metric Measurement			
Equity	Number of needs identified Number of solutions implemented in DACs	Over 67% in a DAC	Between 33% - 67% in a DAC	Less than 33% in a DAC
Emissions	Number of solutions implemented that directly or indirectly reduce emissions	# Direct emissions reduction	# Indirect emissions reduction	# Emissions increase
Local Environmental Impact	Number of solutions implemented that require development of new land	# No new land use or reduces land use	# Moderate increase in land use	# Increases land use

08. Assessment

8. Assessment

This section describes CMP's approach to assessing the effectiveness of the grid plan and progress towards the IGP priorities and enabling the cost-effective achievement of Maine's GHG emission reduction and climate policies. CMP also reflects on lessons learned throughout the first integrated grid planning process and identifies ways to improve and refine future grid plans based on practical experience and feedback.

8.1. Measuring the Effectiveness of the Grid Plan

A smarter, stronger, cleaner and more reliable grid depends on the solutions implemented over the next decade to address the needs identified in this grid plan. Improving reliability and enabling rising demand and DER growth requires rapid and significant upgrades to the grid to add capacity, as well as foundational systems investments to improve grid utilization and manage an increasingly complex grid. New technologies, pilots and innovation will also play a key role in testing and scaling new solutions.

The IGP Order requires utilities to propose metrics or other means to measure the effectiveness of the grid plan and progress towards enabling the cost-effective achievement of the State's GHG emission reduction policies and progress on the three IGP priorities:

1. Reliability and resilience improvements
2. Improve data quality and integrity to maximize its use in distribution system planning
3. Promote flexible management of consumer's resources and energy consumption

Improving reliability and resilience

The utilities already report on standard reliability metrics, including frequency of outages (SAIFI), duration of outages (CAIDI) and time without power (SAIDI), as part of utility report cards established in MPUC Docket 2022-00052. These metrics represent the best way to monitor reliability and measure the effectiveness of investments to improve reliability, which are proposed through the rate case process.

In addition to existing reporting on reliability metrics, CMP proposes to assess progress on improving reliability and resilience by reporting on the following metrics and implementation status of key programs and initiatives in the next IGP:

- Distribution Automation: Status update on implementation, including the percentage of distribution circuits with SCADA devices (currently 85%), across CMP's service territory and in disadvantaged communities (DACs)
- Increase in load serving and DER hosting capacity: Increase load serving and DER hosting capacity demonstrated by an increase in transformer rated capacity, across CMP's service territory and in DACs

- Back-up circuit ties: Percentage of customers connected to a circuit with a viable backup circuit tie (currently less than 40%) across CMP's service territory and in DACs
- Climate Change Resiliency Plan: Progress implementing measures identified in the CCRP, including physical asset resilience measures and operational improvements

Improve data quality and integrity to maximize its use in distribution system planning

CMP is committed to improving data quality and integrity, and proposes to assess progress in leveraging more granular data in distribution planning by reporting on the following metrics and implementation status of key programs and initiatives in the next IGP:

- Leveraging AMI and SCADA data: Integration of AMI and SCADA data into forecasting and system planning
- Improve mapping of the distribution system: Percentage of assets surveyed via field collected data through the Grid Model Enhancement Project (GMEP)
- Time series analysis: Status update on the transition to time series analysis, including new capabilities and benefits
- Hosting capacity maps: Status update on standardization of hosting capacity maps and improvements to support stakeholder decision making

Promote flexible management of consumer's resources and energy consumption

Assessing the potential for flexible management of consumer's resources and energy consumption starts with visibility, and CMP recognizes the importance of working with EMT to gain visibility and identify opportunities for flexible load management. CMP is working towards improving flexible interconnections and advancing a pilot to improve grid utilization. CMP proposes to assess progress by reporting on the following metrics and implementation status of key programs and initiatives in the next IGP:

- DER Interconnections: MW solar and storage interconnected to CMP's distribution grid each year
- Flexible Interconnections: Status update on flexible interconnections for DERs, such as solar and storage, and flexible service connections, such as EV charging stations
- Improve customer engagement: Status update on functionalities available through Energy Manager to help customers understand and manage energy usage
- Advance a pilot to improve grid utilization: Report on the status of a pilot to improve grid utilization, such as peak shaving battery energy storage or Dynamic Line Rating

Below is a summary of the metrics and key initiatives that CMP proposes to report on in the next IGP to provide an update on progress towards the IGP priorities and visibility to EEEJ impacts, as discussed in Section 8. This approach will provide visibility and accountability on the progress of key initiatives such as the transition to time series analysis, flexible interconnections, and advancing pilots such as DLR.

IGP Priority	Metric OR Initiative	Assessment Measure
Improve Reliability and Resiliency	Distribution Automation	% of circuits with Distribution Automation % of customers covered by Distribution Automation
	Increase in load serving and DER hosting capacity	Increase in transformer rated capacity (MW)
	Back-up circuit ties	% of customers connected to a circuit with viable backup circuit ties
	Climate Change Protection Plan	Status update on resiliency measures implemented
Improve Data Quality and Integrity	Integrate AMI and SCADA data into forecasting and system planning analysis	Status update on AMI and SCADA data integration
	Improving mapping of the distribution system	% of distribution grid assets surveyed via field collected data
	Time series analysis	Status update on the transition to time series analysis
	Hosting capacity maps	Status update on standardization and improvements
Promote Flexible Management of Consumer's Resources and Energy Consumption	DER Interconnections	MW solar and storage interconnected to CMP's distribution grid in each year
	Flexible Interconnections	Status update on flexible interconnections for DERs, such as solar and storage, or service connections, such as EV charging stations
	Improve customer engagement	Status update on functionalities available through Energy Manager to help customers understand and manage energy usage
	Pilot to improve grid utilization	Status update on progress, benefits and learnings
EEEJ	Equity	Number of needs identified Number of solutions implemented in DACs
	Emissions	Number of solutions implemented that directly or indirectly reduce emissions
	Local Environmental Impact	Number of solutions implemented that require development of new land

CMP's progress towards addressing the needs identified in this grid plan and meeting many of the IGP priorities is based on its ability to implement key investments and programs via the rate-making process with the appropriate long-term ratemaking constructs that are conducive to multi-year investment planning, as well as through pilot filings.

8.2. Lessons Learned and Next Steps

This inaugural IGP represents an important step toward defining the scope and scale of what it will take over the next ten years to enable and support Maine's climate goals. While the solutions and strategies identified for the next five years are no regrets, there are opportunities to incorporate learnings from the first IGP to improve and enhance the next IGP filing.

Forecasting scenarios: While the CELT 50/50 and 90/10 weather years served as good proxies for a baseline and high electrification scenario in this inaugural IGP, transitioning to scenarios based on differing underlying assumptions for penetration of EVs, heat pumps and DERs would enhance the robustness of the modeling and insights. In addition, there are opportunities to improve the development and reconciliation of bottom-up forecasts with the system total. In this first IGP, CMP developed bottom-up non-coincident substation level forecasts and reconciled those to the CELT total to be compliant with the IGP Order's requirement to use the CELT forecast. In the next IGP, applying percentages of the substation forecasts to CELT forecast would streamline the process and avoid the need to reconcile.

Modeling methodology: One key learning was the limitation of the static modeling snapshot methodology. Without an understanding of the duration and timing of the projected grid overload over the course of the day and year, it is very difficult to assess the potential for alternative solutions such as battery storage or load management to address needs. As discussed in section 6.1, CMP plans to transition to time series analysis. CMP anticipates that using time series analysis to model loading over the 8760 hours in a year will enhance the robustness of the analysis and enable better insights for solutions evaluation.

Scorecard evaluation: While the scorecard analysis yielded insights into a variety of non-cost variables, it could be considered subjective. As stated in the IGP Order, the scorecard was not intended to replace the existing NWA BCA process on a project by project basis, given that detailed analysis of every need was not feasible or practical. In the next IGP, a high-level portfolio BCA approach could be a good option to streamline evaluation based on agreed assumptions. There may be opportunities for enhanced modeling and automation capabilities to streamline portions of the analysis.

09. Conclusion

9. Conclusion

This inaugural Integrated Grid Plan provides a comprehensive roadmap for strengthening Maine's electric grid to meet rising demand, integrate clean energy resources, and improve resilience against increasingly severe storms. CMP's analysis shows that significant capacity constraints and reliability challenges will emerge over the next decade without proactive investment. CMP's plan prioritizes foundational upgrades to substations, circuits, and automation, while advancing data-driven planning and enabling technologies such as ADMS and DERMS to support flexibility and distributed energy resource integration. These strategies will help ensure that Maine's grid evolves to accommodate electrification of heating and transportation, maintain affordability, and align with state climate and energy goals. CMP is committed to delivering a safe, reliable, and sustainable energy future for all customers.

Appendix A: Acronyms

Acronyms	
ADMS	Advanced Distribution Management System
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage Systems
CAIDI	Customer Average Interruption Duration Index
CEJST	Climate And Equity Justice Screening Tool
CCPP	Climate Change Protection Plan
CCRP	Climate Change Resilience Plan
CCVS	Climate Change Vulnerability Study
CMP	Central Maine Power
CO2	Carbon Dioxide
CYME	CYME refers to a simulation tool used to analyze distribution feeders, including basic load allocation, load flow and fault current analysis
DAC	Disadvantaged Community
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DLR	Dynamic Line Ratings
DOE	U.S. Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EMT	Efficiency Maine Trust
EV	Electric Vehicle
GETs	Grid Enhancing Technologies
GHG	Greenhouse Gas
GIS	Geographic Information System
GMEP	Grid Model Enhancement Project
GW	Gigawatt
ISO-NE	Independent System Operator - New England
ISO-NE CELT	ISO-NE's Capacity, Energy, Loads, and Transmission Report
kW	Kilowatt
MPUC	Maine Public Utilities Commission
MW	Megawatt
NWA	Non-Wires Alternative
SAIDI	System Average Interruption Duration Index

Acronyms	
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition

Appendix B: IGP Order Content Outline Attachment (C)

Attachment C

MAINE PUBLIC UTILITIES COMMISSION PROCEEDING TO IDENTIFY PRIORITIES FOR GRID PLAN FILINGS

Docket No. 2022-00322

GRID CONTENT OUTLINE

Expected Content of Grid Plans

The following outline summarizes content that the Maine Public Utilities Commission (MPUC) would expect to see included in the utilities' grid plans. This outline draws on stakeholder feedback from this docket, research by the Commission's consultant, Electric Power Engineers (EPE), as well as best practices from other jurisdictions that have begun implementing integrated grid planning (IGP) processes. The expected content, as shown below, is currently outlined at a high level.

1. **Vision for the Evolving Grid**
   a. Discussion of the utilities' vision for the next 10 years and a discussion of how their proposed investments and operations will achieve the priorities identified in this proceeding, improve reliability and resiliency and enable the cost-effective achievement of the State's greenhouse gas (GHG) reduction obligations and climate policies. The grid plans must include a roadmap of the utility's near-term and long-term planned investments and operations.
   b. Roles of third-party stakeholders in Grid Needs Assessment and Grid Plan
   c. Technology deployment strategies necessary to meet objectives outlined above during the planning horizon
   d. Efforts planned or currently underway regarding regulatory and policy changes such as:
      a. Utility role in distributed energy resource (DER) aggregation mechanisms (Federal Energy Regulatory Commission (FERC) Order 2222)
      b. Generator interconnection reforms (FERC Order 2023)
      c. Regional Transmission Planning and Cost Allocation Reforms (FERC Order 1920)
      d. Other recent FERC or MPUC orders
      e. Recent federal or State laws (*e.g.*, Inflation Reduction Act)
2. **System Overview**
   a. Transmission and Distribution System Data
      a. Total distribution substation capacity in kilovolt-amperes (kVA)
      b. Total distribution transformer capacity in kVA
      c. Total miles of overhead distribution wire
      d. Total miles of underground distribution wire
      e. Transmission and Distribution Asset Health Reports
      f. Total number of distribution premises
      g. Number of customer meters with advanced meter infrastructure (AMI), number of those without AMI, planned AMI investments, and an overview of the functionalities available

h. Existing and planned modeling software
i. Percentage of substations and feeders with monitoring and control capabilities (e.g., supervisory control and data acquisition (SCADA)) and planned additions. Include any appropriate differences in functionality or data availability where appropriate
j. A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (e.g. maximum/minimum, daytime/nighttime, monthly/daily reads, automated/manual)
k. System Level System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) data for the past 5 years

b. Financial Data
    a. Historical distribution and transmission system spending for the past 5 years, broken down by category. For each category, provide a description of what items and investments are included
    b. Projected distribution and transmission system spending for the next 5 years for the same categories
    c. Planned distribution and transmission capital projects, including drivers and timelines for each project, and a summary of anticipated changes in historic spending
    d. Description of preliminary cost recovery plans and how regulatory approval will be sought.

c. DER Deployment
    a. Current DER deployment by type, size, and geographic dispersion
    b. Total number of projects and nameplate rating (kilowatt (kW), include kilowatt-hour (kWh) for storage) of DER interconnected to the system in each of the last 5 years, broken down by DER technology type (e.g., solar, combined solar/storage, storage, etc.)
    c. Total number of queued DERs and nameplate rating (kW, include kWh for storage), broken down by DER technology type (e.g., solar, combined solar/storage, storage, etc.)
    d. Total number of electric vehicles (EVs) in service territory (known or estimated)
    e. Total number and capacity of public EV charging stations (known or estimated)
    f. Total number of battery storage units and nameplate rating (megawatt (MW) and megawatt-hour (MWh))

3. Forecasting and Scenario Development

a. Two forecasts
    a. Baseline forecast
        1. Load forecast: most recent vintage Capacity, Energy, Loads, and Transmission (CELT) (2024) 50-50 weather year; including

distributed generation (DG), transport, and heating electrification; disaggregated to the distribution system circuit level
        2. Supply assumptions: most recent vintage CELT (2024)
    b. High DER Penetration & Electrification forecast
        1. Load forecast: most recent vintage CELT (2024) 90-10 weather year; including DG, transport, and heating electrification; disaggregated to the distribution system circuit level
        2. Supply assumptions: most recent vintage CELT (2024)
  b. Six Snapshots of each forecast
    a. Summer Daytime Peak Load
    b. Summer Evening Peak Load
    c. Winter Evening Peak Load
    d. Daytime Minimum Load
    e. Evening Minimum Load
    f. Spring Minimum Load

4. **System Modeling and Needs Identification**
    a. Distribution planning criteria and current practices for needs identification (e.g. reliability/cost analysis, equipment ratings methodology, contingency planning requirements)
        a. Alignment with minimum service quality standards set under MPUC Chapter 320 rules and 35-A M.R.S. §301
        b. Alignment with any other service quality targets (e.g. rate case mechanisms, internal goals, benchmarking levels)
    b. Summary of distribution and transmission system needs
    c. Climate Change Protection Plan results
    d. Time-series modeling progress and utilization
    e. Data availability to public/third parties
    f. Discussion of alignment with the State's GHG emission reduction and climate policies (e.g., Pathway to 2040)
5. **Solutions Identification and Evaluation**
    a. Capital project evaluation and alternative comparison framework, including benefits and risks considered, quantification of value (reliability, environmental, efficiency, equity, etc.), resource cost and capabilities assumptions, reconciliation of future needs across multiple potential scenarios and investment prioritization methods and tools
        a. Scorecard as attached to the Order in Attachment D
        b. Narrative explanation of scoring process and scorecard results
    b. Connection between scorecard and:
        a. Internal utility capital planning process,
        b. Nonwires Alternatives (NWA) and NWA coordination process with Efficiency Maine Trust (Trust), and
        c. Impact of Trust programs or other programs (e.g., Federal, including efforts to obtain Federal funding to reduce ratepayer impacts) on capital

investment needs, including collaborative efforts with Trust to identify possible impacts beyond Trust triennial plan period.

6. **Technology, Integration, Systems Investments and Pilot Projects**
   a. Systems
      a. Analysis of available and emerging technologies necessary to enable demand response, load management, and flexibility (e.g., Grid Edge/Enhancing Technology)
      b. Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management Systems (DERMS) vision, plans, evaluation, and compatibility or synergies with third-party entities (e.g., Trust)
      c. Near-term and long-term technology investments related to distribution planning and operations
      d. Progress adopting roadmap report recommendations established in Grid Modernization Case (2021-00039)
      e. Hosting capacity process and results: Analysis of DER and load hosting capacity, including locational benefits of DER and areas of existing or potential system congestion
      f. Application processing and queue management for load and generation
      g. System integration and data management

   b. Pilot Projects
      h. Existing pilot projects status and findings
      i. Emerging rate design and/or demand response concepts being considered for pilot development
      j. Emerging technologies or applications being explored
      k. Emerging needs likely to require new tools or solutions
      l. Timeline and staging/dependencies for implementing new technologies
7. **Environmental, Equity, and Environmental Justice**
      a. Describe how the environmental, equity, and environmental justice (EEEJ) impacts were determined and weighted against other considerations in the planning process and investment prioritization
      b. Include a list of all outreach or events where the EEEJ impacts were addressed, along with specific examples of how this impacted the grid plan
      c. Include a list of any required follow up, or additional planned outreach that addresses the EEEJ impacts of the grid plan
      d. Propose metrics or other means to measure or evaluate and track these impacts in the near and longer term.
8. **Assessment**
   a. Proposed metrics or other means to measure the effectiveness of the grid plan and progress towards the priorities and improving reliability, resiliency and enabling the cost-effective achievement of the State’s GHG emission reduction and climate policies. Within the evaluation framework, the utilities should include

lessons learned and proposed changes to future planning assumptions and methodologies.

Appendix C: Planned Transmission and Distribution Project List

Project Name	Project Type	Voltage (kV)	Estimated In-Service Date	Driver(s)
Asset Condition Structure Replacement Program	Transmission	345/115	2028	Asset Condition
Baldwin to Shaw Mills Tie	Distribution	34.5/12.47	2026	Reliability, Capacity
Bolt Hill Rebuild	Substation (Transmission)	115	2028	Reliability, Capacity, Asset Condition
Brighton Ave S/S Upgrades	Substation (Distribution)	34.5/12.47	2027	Asset Condition, Reliability
Butlers Corner S/S Mods	Substation (Distribution)	34.5/12.47	2026	Asset Condition
Deer Rips S/S Mods	Substation (Distribution)	34.5/12.47	2029	Asset Condition, Reliability
Detroit-Guilford-Carmel Upgrades	Transmission/Substation/ Distribution	115	2028	Reliability, Capacity
Distribution Automation Program	Distribution	34.5/12.47	2026	Automation, Reliability
DOE DA Grant Program 2025-2029	Distribution	34.5/12.47	2029	Reliability
Factory Island S/S Mods	Substation (Distribution)	34.5/12.47	2026	Reliability
Greater Portland Transmission Upgrades Phase 1	Substation/Transmission	115/34.5	2031	Capacity, Reliability, Asset Condition
Highland Rebuild	Substation (Transmission)	115	2029	Capacity, Reliability, Automation
Hinckley Pond S/S Upgrade	Substation (Distribution)	115/12.47	2027	Capacity, Reliability
Kent Hill Reconductor	Distribution	34.5	2026	Asset Condition, Reliability
Larrabee Road Breaker Replacement	Substation (Transmission)	115	2028	Reliability
MEPCO 396/3001 Structures Replacement	Transmission	345	2030	Asset Condition
New Circuit Construction - Goosefare 630D5	Distribution	34.5/12.47	2026	Capacity
Portland Rd Reconductor	Distribution	12.47	2026	Asset Condition, Reliability
Readfield Rd Reconductor	Distribution	12.47	2027	Asset Condition
Resiliency Project Circuit 258D1 (Woolwich)	Substation (Distribution)	12.47	2026	Resiliency
Reverse Power Relaying Program	Substation (Transmission)	115	2026	Reliability
RTU Replacement Program	Substation (Transmission)	115	2026	Relaibility, Automation
Section 31 Rebuild	Transmission	34.5	2026	Asset Condition
South Berwick S/S Mods	Substation (Distribution)	34.5/12.47	2026	Asset Condition, Reliability
Substation Automation Program	Substation (Transmission)	115/34.5	2026	Reliability, Automation
Town Farm Rd Reconductor	Distribution	34.5	2026	Reliability, Asset Condition
Transmission Automation Program	Transmission	115/34.5	2026	Reliability

Transmission SCADA Switch Program	Transmission	115/34.5	2028	Automation, Reliability
Turner Center Rd Reconductor	Distribution	12.47	2027	Capacity
URD Program	Distribution	12.47	2026	Asset Condition
Wilton High Line Express Feed	Distribution	12.47	2026	Asset Condition, Reliability
Wyman Hydro S/S	Substation (Transmission)	115	2028	Reliability, Asset Condition

Appendix D: Regional System Plan Projects (ISO-NE) Included in CMP IGP Cases

All projects listed below form part of the infrastructure background for the modelled transmission networks by 2034. Those projects have received PPA approval (proposed plan of action). This means these projects were approved by the New England Power Pool (NEPOOL) Reliability Committee (RC) pursuant to section I.3.9 of the ISO-NE tariff.

Regional System Projects (RSP)	Details
RSP 1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland – Coopers Mills 115 kV line (UME 2029 Solution)
RSP 1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer (UME 2029 Solution)
RSP 1884	Install a 15 MVAR capacitor at Belfast 115 kV substation (UME 2029 Solution)
RSP 1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation (UME 2029 Solution)
RSP 1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker and a 13.8 kV breaker (NH 2029 Solution)
RSP1881	Install two 50 MVAR capacitors on Line 363 near Seabrook station with three 345 kV breakers (NH 2029 Solution)
RSP1886	Install a +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements (UME 2029 Solution)
RSP1887	Install a 25 MVAR reactor at Boggy Brook 115 kV substation (UME 2029 Solution)
RSP1888	Install a 10 MVAR reactor at Keene Road 115 kV substation (UME 2029 Solution)
RSP1893	Install two +300/-300 MVAR STATCOMs at the Buxton 345 kV Substation with one new 345 kV breaker (QP889)
RSP1894	Reconductor the Section 62 115 kV line (QP889)
RSP1895	Reconductor the Section 64 115kV (QP889)
RSP1896	Add a series breaker at the Scobie Pond 345 kV Substation (QP889)
RSP1897	Add a series breaker at the Deerfield 345 kV Substation (QP889)
RSP1914	Install a new 80 MVAR reactor, configure the existing two reactors at the 345 kV Orrington substation

Appendix E: Scorecard framework for 16 categories identified

System Needs, Categories and Corresponding Scorecard Templates

Needs					Category	# of Needs
Needs	Distribution	Near term Thermal Violations	Circuit	Low severity	1	10
Needs	Distribution	Near term Thermal Violations	Circuit	Medium severity	2	43
Needs	Distribution	Near term Thermal Violations	Circuit	High severity	3	28
Needs	Distribution	Near term Thermal Violations	Transformer	Low severity	4	10
Needs	Distribution	Near term Thermal Violations	Transformer	High severity	5	75
Needs	Distribution	Long term Thermal Violations	Circuit	Low severity	6	41
Needs	Distribution	Long term Thermal Violations	Circuit	High severity	7	1
Needs	Distribution	Long term Thermal Violations	Transformer	Low severity	8	27
Needs	Distribution	Long term Thermal Violations	Transformer	High severity	9	3
Needs	Distribution	DER-driven Violations[1]			10	39
Needs	Transmission	Thermal Violations	Transmission line	Low severity	11	29
Needs	Transmission	Thermal Violations	Transmission line	Medium severity	12	43
Needs	Transmission	Thermal Violations	Transmission line	High severity	13	35
Needs	Transmission	Thermal Violations	Transformer[2]		14	34
Needs	Transmission	Voltage Violations[2]			15	76
Needs	Transmission	DER-driven Violations[1]			16	221

Not further categorized because: 1) DER-driven violations are customer-specific; 2) transmission voltage violations are inherently specific; or need is attenuated.

Scorecard template 1: Feeder circuit minor overload, near term

Description of System Need:		***Category 1: Distribution Feeder Circuits Overload, Load driven, <110% (minor overloading), Near term***			
	Evaluation Category	**Comparative Assessment Scorecard**			
		Alternative A: Load Shift	**Alternative B:** Recondutoring	**Alternative C:** New Circuit	**Alternative D:** BESS
Cost	**Capital costs**				
	Operations & maintenance costs				
	Avoided costs				
Technical Performance	**Efficacy**				
	Execution and schedule risk				
	Existing infrastructure optimization				
	Reliability & resiliency impact				
	Flexible management of customers' load and generation				
EEEJ	**Equity**				
	Emissions impact				
	Local environmental impact				
Policy Alignment	**Peak load reduction**				
	Electrification readiness				
	DER and renewables integration				
	Advances state energy and climate goals				
	Overall prioritization ranking	1	2	4	3
Scorecard Narrative:	**Costs**	*In cases of minor/moderate circuit overload—such as operating at 110% capacity—non-wires alternatives (NWAs) can be particularly effective in addressing system needs without resorting to traditional infrastructure upgrades. However, current limitations in supply chain maturity and technology readiness may result in higher total expenditures (TOTEX) for these solutions. In contrast, certain conventional mitigation strategies, such as load shifting—if technically and economically viable—can represent the most cost-effective option.*			
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS.*			
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*			
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*			

Scorecard template 2: Feeder circuit medium overload, near term

Description of System Need:		***Category 2: Distribution Feeder Circuits Overload, Load driven, 110% - 150% (medium overloading), Near term***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Reconductoring	**Alternative B:** New Circuit	**Alternative C:** Smart Grid Technologies BESS
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	3	2
Scorecard Narrative:	**Costs**	*In cases of moderate circuit overload—such as operating at 110% -150%capacity— it would normally require detailed studies. While non-wires alternatives (NWAs) can be effective in addressing system needs without resorting to traditional infrastructure upgrades, current limitations in supply chain maturity and technology readiness may result in higher total expenditures (TOTEX) for these solutions. In contrast, certain conventional mitigation strategies, such as reconductoring, can represent the most cost-effective option.*		
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*		

Scorecard template 3: Feeder circuit severe overload, near term

Description of System Need:		*Category 3: Distribution Feeder Circuits Overload, Load driven, >150% (severe overloading), Near term*		
	Evaluation Category	Comparative Assessment Scorecard		
		Alternative A: Reconductoring	**Alternative B:** New Circuit	**Alternative C:** New Configuration with network enhancement
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	3	2	1
Scorecard Narrative:	**Costs**	*In cases of severe constraints—such as operating over 150% capacity— established mitigations will come with advantages as coordinated and cost effective solutions. Due to the current TRL, the additional system capacity required at this level and corresponding incremental costs will often price out NWA.*		
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*		

Scorecard template 4: Transformer minor overload, near term

Description of System Need:		*Category 4: Distribution Transformer Overload, Load driven, <110% (minor overloading), Near term*		
	Evaluation Category	Comparative Assessment Scorecard		
		Alternative A: Transformer Upgrade	**Alternative B:** Additional Transformer	**Alternative C:** BESS
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	3	2
Scorecard Narrative:	**Costs**	*In cases of minor/moderate transformer overload—such as operating below 110% capacity—non-wires alternatives (NWAs) can be particularly effective in addressing system needs without resorting to traditional infrastructure upgrades. However, the size of battery requires detailed desigen. Current limitations in supply chain maturity and technology readiness may result in higher total expenditures (TOTEX) for these solutions.*		
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*		

Scorecard template 5: Transformer severe overload, near term

Description of System Need:		*Category 5: Distribution Transformer Overload, Load driven, >110% (medium/severe overloading), Near term*		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Transformer Upgrade	**Alternative B:** Additional Transformer	**Alternative C:** BESS
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	3	2
Scorecard Narrative:	**Costs**	*In cases of moderate/severe constraints—such as operating over 110% capacity— established mitigations will come with advantages as coordinated and cost effective solutions. Due to the current TRL, the additional system capacity required at this level and corresponding incremental costs will ofgen price out NWA.*		
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*		

Scorecard template 6: Feeder circuit minor overload, long term

Description of System Need:		*Category 6: Distribution Feeder Circuits Overload, Load driven, <110% (minor overloading), Long term*		
	Evaluation Category	Comparative Assessment Scorecard		
		Alternative A: Reconductoring	**Alternative B:** New Circuit	**Alternative C:** BESS
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	2	3	1
Scorecard Narrative:	**Costs**	*In cases of minor/moderate circuit overload—such as operating at 110% capacity—non-wires alternatives (NWAs) can be particularly effective in addressing system needs without resorting to traditional infrastructure upgrades. It would be expected that both TRL and CRL can be improved over the coming years - with a reduced total expenditures (TOTEX), solutions such as BESS can be more competitive.*		
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS. If piloted and tested properly over the coming years, project executive risks can also be reduced for NWA.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*		

Scorecard template 7: Feeder circuit medium- severe overload, long term

Description of System Need:		***Category 7: Distribution Feeder Circuits Overload, Load driven, 110%-150% (minor overloading), Long term***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Reconductor	**Alternative B:** New Circuit	**Alternative C:** BESS
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	3	2
Scorecard Narrative:	**Costs**	*It would be expected that both TRL and CRL can be improved over the coming years for NWA solutions such as BESS - with a reduced total expenditures (TOTEX), solutions such as BESS can be more competitive. However, there are many factors impacting on the costs of NWA, from raw material to the competition level of supplier chains.*		
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS. If piloted and tested properly over the coming years, project executive risks can also be reduced for NWA.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*		

Scorecard template 8: Transformer minor overload, long term

Description of System Need:		***Category 8: Distribution Transformer Overload, Load driven, < 110% (minor overloading), Long term***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Transformer Upgrade	**Alternative B:** New Transformer	**Alternative C:** BESS
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	2	3	1
Scorecard Narrative:	**Costs**	*In cases of minor/moderate circuit overload—such as operating below 110% capacity—non-wires alternatives (NWAs) can be particularly effective in addressing system needs without resorting to traditional infrastructure upgrades. It would be expected that both TRL and CRL can be improved over the coming years - with a reduced total expenditures (TOTEX), solutions such as BESS can be more competitive.*		
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS. If piloted and tested properly over the coming years, project executive risks can also be reduced for NWA.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*		

Scorecard template 9: Transformer medium/severe overload, long term

Description of System Need:		*Category 9: Distribution Transformer Overload, Load driven, >110% (medium/severe overloading), Long term*		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Transformer Upgrade	**Alternative B:** Additional Transformer	**Alternative C:** BESS
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	3	2

Scorecard Narrative:	**Costs**	*In cases of severe transformer constraints—such as operating around150% capacity— established mitigations will come with advantages as coordinated and cost effective solutions. Even with the envisaged improvements of TRL/CRL, the additional system capacity required at this level and corresponding incremental costs can still price out NWA.*
	Technical Performance	*Established reinforcements will come with mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience. However, customer load/generation would be flexibly managed with BESS.*
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*

Scorecard template 10: system needs due to DER driven

Description of System Need:		***Category 10: Distribution Feeder Circuits Overloading, Driven by DER Interconnections***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: New Circuit	**Alternative B:** BESS, potentially with Microgrid	**Alternative C:** DER Mangement (DERM)
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	3	2	1

Scorecard Narrative:	**Costs**	*While the majority of the mitigation costs triggered by DER interconnection will be undertaken by individual developers, it is important to have the overall cost-effective solutions without having adverse impact on the system capacity or on the rate payers. The comparison is based on the TOTEX available at the moment.*
	Technical Performance	*DER developers would have the commercial model and associated control algorithm when it comes to the flexible control of the resources. Such control can also be linked with demand flexibility. If coordinated and planned properly with the right portfolio os resources/demand, the smart grid technology could defer/avoid conventional reinforcement.*
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage and DERM are shown to align well due to the peak load shaving and management flexibility qualities.*

Transmission Scorecard Template 11

Description of System Need:		***Category 11: Transmission Circuits Overloading <110% (Minor overloading), Load Driven***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Reconductor	**Alternative B:** New Circuit	**Alternative C:** Grid Enhancement Technologies such as Energy Storage (BESS)
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	3	2

Scorecard Narrative:	**Costs**	*The voltage and power flow levels in a transmission network require much higher mitigation capacity compared to distribution, even in cases of minor or moderate circuit overload—such as operating at 110% capacity. This could result in a substantial footprint and higher total expenditures (TOTEX) for batteries compared to established options. Advanced conductors (commonly refer to HTLS) may introduce higher losses along the circuit and require partial enhancement of existing infrastructure. Dynamic Line Rating is subject to detailed surveys along the route and climate forecasts, necessitating proper planning and design in advance to identify and tailor solutions for specific circuits.*
	Technical Performance	*Established reinforcements will come with tested process in delivery; mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience (such as Intact and N-1 scenario). However, customer load/generation will be flexibly managed with BESS.*
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template energy storage is shown to align well due to the peak load shaving and management flexibility qualities.*

Transmission Scorecard Template 12

Description of System Need:		***Category 12: Transmission Circuits Overloading, 110%-150% (Medium overloading), Load Driven***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Reconductoring	**Alternative B:** New Circuit	**Alternative C:** Grid Enhancement Technologies such as Dynamic Line Rating
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	3	2
Scorecard Narrative:	**Costs**	*The voltage and power flow level at transmission network require much higher mitigating capacity compared with distribution. The moderate circuit overload—such as operating at 130% capacity could normally price out some Grid Enhancement Technologies (such as BESS). Dynamic Line Rating is subject to detailed survey along the overall route and climate forecast, requiring proper planning and design in advance to identify and tailor the solutions for certain circuits. It has also annual operational costs.*		
	Technical Performance	*Established reinforcements will come with tested process in delivery; mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience (such as Intact and N-1 scenario). However, customer load/generation will be flexibly managed by Dynamic Line Rating, if properly studied and coordinated.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template a GET is shown to align well.*		

Transmission Scorecard Template 13

Description of System Need:		***Category 13:Transmission Circuit Overloading >150% (Severe overloading), Load Driven***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: New Circuit	**Alternative B:** Reconductoring	**Alternative C:** Grid Enhancement Technologies such as High Temp Low Sag conductor
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	3	2
Scorecard Narrative:	**Costs**	*The severe overloading (such as >=150%) at any transmission circuit would require a sysmatic review due to its interconnecting nature with other parts of the network. Bespoke solutions such as reconductor or individual GET could play a supplement role if the foundamental configeration of transmission network is fit for purpose. Advanced conductors will come with higher losses over the circuit and require partial enhancement of existing infrastructure. Dynamic Line Rating is subject to detailed survey along the route and climate forecast, requiring proper planning and design in advance to identify and tailor the solutions for certain circuits.*		
	Technical Performance	*Established reinforcements will come with tested process in delivery; mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience (such as Intact and N-1 scenario). However, customer load/generation will be flexibly managed with technologies such as BESS.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template a GET is shown to align well.*		

Transmission Scorecard Template 14

Description of System Need:		***Category 14:Transmission Transformer Overload, Load Driven***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Transformer Upgrade	**Alternative B:** Parallel Transformer (by adding one new)	**Alternative C:** Grid Enhancement Tech such as BESS
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	1	2	3

Scorecard Narrative:	**Costs**	*Across the spectrum of transformer overloading scenarios, certain cases can be mitigated through operational measures such as load shifting (i.e., transferring demand to other transformers) or, in more extreme situations, through fundamental changes such as building a new substation. This scorecard is designed to represent the majority of overloading cases under the existing network topology. Most of these cases will require significantly greater mitigation capacity compared to distribution-level issue: even for moderate transformer overloads, such as operating at 130% of rated capacity. Addressing these challenges could require substantial physical footprint requirements and higher total expenditures (TOTEX) for Grid Enhancement Technologies (e.g., BESS-Battery Energy Storage Systems), compared to conventional solutions, compounded by the spatial constraints typical of substations.*
	Technical Performance	*Established reinforcements will come with tested process in delivery; mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience (such as Intact and N-1 scenario). However, customer load/generation will be flexibly managed with BESS.*
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template a GET is shown to align well.*

Transmission Scorecard Template 15

Description of System Need:		***Category 15: Voltage Violation, Load Driven***		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: Capacitor Bank	**Alternative B:** Statcom (Static Compensation)	**Alternative C:** Synchronous Condenser
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	2	1	3
Scorecard Narrative:	**Costs**	*To address voltage issues on the transmission network, established solutions vary in cost and complexity. Capacitor banks are generally the most cost-effective option, while synchronous generators represent the most expensive when it comes to CAPEX. In addition, synchronous generators require energy to operate and maintain, resulting in higher ongoing operational costs compared to passive solutions (OPEX). Static Compensation (Statcom) is widely deployed over transmission networks.*		
	Technical Performance	*From a technical performance perspective, capacitor banks offer a cost-effective solution but cannot provide dynamic voltage support. In contrast, synchronous generators deliver both voltage regulation and inertia support, which strengthens a weak transmission network and improves system reliability. STATCOMs, on the other hand, can provide fast dynamic voltage response but do not contribute to system inertia. For the time being, the requirement of inertia support is not urgent at CMP system.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template a Statcom is shown to align well.*		

Transmission Scorecard Template 16

Description of System Need:		*Category 16: DER Driven System Needs*		
	Evaluation Category	**Comparative Assessment Scorecard**		
		Alternative A: New Circuit	**Alternative B:** Energy Storage (BESS)	**Alternative C:** Dynamic Line Rating
Cost	**Capital costs**			
	Operations & maintenance costs			
	Avoided costs			
Technical Performance	**Efficacy**			
	Execution and schedule risk			
	Existing infrastructure optimization			
	Reliability & resiliency impact			
	Flexible management of customers' load and generation			
EEEJ	**Equity**			
	Emissions impact			
	Local environmental impact			
Policy Alignment	**Peak load reduction**			
	Electrification readiness			
	DER and renewables integration			
	Advances state energy and climate goals			
	Overall prioritization ranking	3	2	1
Scorecard Narrative:	**Costs**	*While the majority of costs of enabling reinforcements for DER interconnections will be borne by individual developers, CMP maintains its responsibility for a coordinated approach to ensure system capacity, affordability, and reliability are not compromised. This scorecard demonstrates CMP's commitment to its role as a facilitator of DER integration. CMP is actively collaborating with partners to identify opportunities for piloting grid enhancement technologies—such as dynamic line rating—to enable earlier access to the grid. If feasibility studies confirm viability, installing dynamic line rating would involve ongoing costs for both hardware and software to support continuous operation and monitoring.*		
	Technical Performance	*Established reinforcements will come with tested process in delivery; mature industry standards in delivery and commissioning. The enduring and firm capacity provided will offer great advantage when it comes to resilience (such as Intact and N-1 scenario). However, customer generation can be flexibly managed with BESS.*		
	EEEJ	*EEEJ scores are highly project-dependent because of local population and land variables, and actual scores would be updated accordingly when applied to a specific project.*		
	Policy Alignment	*The relative benefit of any proposed solutions may be fairly subjective, and may be project-specific, since creating capacity achieves policy alignment as well as integration of renewables. For this scorecard template a GET is shown to align well.*		